In the Matter of the Application of San Diego Gas & Electric Company (U 902 E) for Approval of its Proposals for Dynamic Pricing and Recovery of Incremental Expenditures Required for Implementation.	Application 10-07-009 (Filed July 6, 2010)
Application of San Diego Gas & Electric Company (U 902 E) for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design	Application 19-03-002 (Filed March 4, 2019)

Application: 10-07-009/A.19-03-002
Exhibit No.: ________

CHAPTER 5

PREPARED REBUTTAL TESTIMONY OF

WILLIAM G. SAXE

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MAY 4, 2020

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PREPARED REBUTTAL TESTIMONY OF

WILLIAM G. SAXE

(CHAPTER 5)

I. OVERVIEW AND PURPOSE

The purpose of this prepared rebuttal testimony is to address the following direct testimony submitted on marginal distribution customer and demand cost, and revenue allocation issues by:

- The Public Advocates Office ("Cal Advocates"), submitted as amended prepared testimony of Nathan Chau (Chapter 1), Jake McDermott and Ryan Saraie (Chapter 2), Christopher Hogan (Chapter 4), and Christopher Danforth (Chapter 7), dated April 6, 2020;
- California City County Street Light Association ("CALSLA"), submitted as prepared direct testimony of Alison Lechowicz, dated April 6, 2020;
- The Federal Executive Agencies ("FEA"), submitted as direct testimony of Maurice Brubaker, dated April 6, 2020;
- Small Business Advocates ("SBUA"), submitted as direct testimony of Paul L. Chernick, dated April 6, 2020;
- San Diego Airport Parking Company ("SDAP"), submitted as opening testimony of Robert Levin and Lisa McGhee, dated April 6, 2020;
- Solar Energy Industries Association ("SEIA"), submitted as prepared direct testimony of R. Thomas Beach, dated April 6, 2020;
- The City of San Diego ("The City"), submitted as direct testimony of William A. Monsen, dated April 6, 2020;

- The Utility Reform Network ("TURN"), submitted as revised prepared testimony of Jaime McGovern, dated April 23, 2020; and
- The Utility Consumers' Action Network ("UCAN"), submitted as direct testimony of Mary Neal, dated April 6, 2020.

Specifically, my prepared rebuttal testimony provides the following conclusions regarding recommendations raised by the above witnesses:

- The California Public Utilities Commission ("CPUC" or "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,[1] as presented in Section II.E, because it is the better methodology to use to calculate marginal distribution customer costs when compared to the New Customer Only method ("NCO Method"), proposed by Cal Advocates, CALSLA, SBUA, and TURN, as described in Section II.A.
- If the CPUC ultimately adopts the marginal distribution customer costs based on the NCO Method, it should include final line transformer, service drop, and meter ("TSM") replacement costs in the calculation as proposed by SDG&E, that Cal Advocates opposes, because the replacement of TSM equipment results in a real cost that should be included in the calculation of marginal distribution customer costs, as described in Section II.D.
- The CPUC should reject TURN's proposal to exclude final line transformer costs in the calculation of marginal distribution customer costs because the

[1] FEA Direct Testimony, p. 6.

cost of final line transformers has been adopted as marginal distribution customer costs by the CPUC since final line transformers reflect distribution facilities required to provide electric service to individual customers taking service at secondary service levels, as described in Section II.B.

- UCAN's proposal to evaluate the difference in service drop costs of a relatively small number of SDG&E's customers that share service drops has merit; however, because the full set of data needed to evaluate shared service drop costs is currently not available, the CPUC should adopt the service drop costs proposed by SDG&E for use in developing marginal distribution customer costs in this proceeding and encourage SDG&E to work with UCAN prior to its next GRC Phase 2 proceeding to figure out the best way to address UCAN's concern, as discussed in Section II.C.
- The CPUC should adopt marginal distribution demand costs based on the National Economic Research Associates ("NERA") regression analysis, proposed by SDG&E, as presented in Section III.I, with the methodology supported by Cal Advocates and opposed by UCAN, as discussed in Section III.F.
- Cal Advocates' proposed reassignment of distribution capital costs agreed to by SDG&E, as presented in Attachment D, should be adopted by the CPUC for use in the calculation of marginal distribution demand costs, as discussed in Section III.A.
- Cal Advocates' proposal to require SDG&E to develop its marginal distribution demand costs based on actual distribution capital expenditures is

not needed because SDG&E is already required to report actual distribution capital expenditures for 2017-2019 that SDG&E proposes be included in the calculation of marginal distribution demand costs in this proceeding, as describe in Section III.B.

- CPUC should reject Cal Advocates' proposed modification to the formulas used to allocate easement and overhead pool costs to capacity-related costs because the formulas SDG&E proposes to allocate easement and overhead pool costs are correct, as described in Section III.C.
- CPUC should approve Cal Advocates' proposed modifications to the General Plant ("GP"), Working Capital ("WC"), and Administrative & General ("A&G") load factors used in the calculation of marginal distribution customer and demand costs, as described in Section III.D.
- CPUC should approve Cal Advocates' proposed modification to the Fixed Operation & Maintenance ("O&M") costs used in the calculation of marginal distribution demand costs with one modification to correctly assign these costs based on customer and demand allocation factors, as described in Section III.E.
- CPUC should reject Cal Advocates' proposal that SDG&E be required to analyze the impact of behind-the-meter ("BTM") photovoltaics ("PV") and energy efficiency load and how the BTM load should be reflected in the load data used in future GRC Phase 2 proceedings because SDG&E's distribution planning engineers already correctly analyze the load required to provide

reliable service to its customers with PV and energy efficiency in place, as described in Section III.G.

- SDAP's proposal for SDG&E to be required to calculate the distribution costs that are time-variant for use in the Contribution to Marginal ("CTM") analyses should be disregarded because SDG&E already calculates the portion of its distribution costs that is time-variant, as described in Section III.H.
- Cal Advocates' proposal to correct the marginal distribution demand cost ("MDDC") scaling in the distribution revenue allocation should be disregarded because SDG&E scaled the MDDC correctly and actually consistently with how Cal Advocates scaled the MDDC, as described in Section IV.A.

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;
- **Attachment D –** Proposed Reassignment of Electric Distribution Capital Budget Items; and
- **Attachment E -** Forecasted Distribution Capacity Costs Compared to Actual Distribution Capacity Costs.

In this prepared rebuttal testimony, failure to address any individual issue does not imply any agreement by SDG&E with the proposal made by these or other parties.

II. MARGINAL DISTRIBUTION CUSTOMER COSTS

A. Rental Method versus NCO Method

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

Cal Advocates, CALSLA and SBUA assert that the CPUC has decided in prior decisions that the NCO Method is the better method to calculate marginal distribution customer costs. These parties imply that the CPUC 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.[2]

SDG&E disagrees with Cal Advocates, CALSLA and SBUA that prior CPUC decisions adopting the use of NCO Method in proceedings more than two decades ago in non-SDG&E electric proceedings should set the precedent for the marginal distribution customer cost methodology adopted in this proceeding.[3] Which methodology to use in developing marginal distribution customer costs has always been a complicated and contentious issue in rate design proceedings. SDG&E recommends that the CPUC determine its preferred marginal distribution customer cost methodology in this proceeding based on evidence presented in this proceeding and not evidence presented in non-SDG&E proceedings. As discussed in Section II.A 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 more accurate price signals regarding distribution customer costs, and provides more accurate and

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[2] Cal Advocates Amended Prepared Testimony, pp. 1-7 – 1-8; CALSLA Prepared Direct Testimony, p. 3; and SBUA Direct Testimony, p. 4.
[3] *See, e.g.,* Cal Advocates Amended Prepared Testimony, p. 1-3, n.20 (*citing* D.92-12-057, D.97-03-017, D.96-04-050, and D.00-04-060).

less volatile allocations of authorized distribution revenue requirements based on distribution customer costs.

Although not a decision in an electric utility proceeding, the CPUC's recent Decision ("D.") 20-02-045 is instructive in adopting the Rental Method to develop marginal distribution customer costs for SDG&E Gas and Southern California Gas Company ("SoCalGas"). In D.20-02-045, the CPUC stated:

> As discussed below, we find that neither the Rental Method nor the New Customer Only Method are optimal approaches to determining marginal costs. However, the results of the Rental Method provide the Commission marginal costs with less dramatic increases across all customer classes, thus avoiding disproportionate rate impacts to customer classes with few new customers. The use of the Rental Method in this proceeding will result in the most reasonable revenue allocation and near cost-based rates for SoCalGas and SDG&E customers.[4]

> In the past, the Commission has supported both methods for varying reasons. Parties discuss the Commission support of the Rental Method in D.92-12-058, while parties opposing the Rental Method discuss Commission support of the New Customer Only Method in D.95-12-053. Most recently, in D.19-10-036, the Commission adopted a marginal cost study based on the Rental Method, stating that it "will result in the most reasonable revenue allocation and the most reasonable cost-based rates" for customers. The Commission found that the use of the Rental Method would "produce results that are fair across customer classes" and would "avoid disproportionate rate impacts to customer classes that have few new entrants."[5]

> In this review of the two methods, we are faced with the same arguments that these parties have presented in prior proceedings. Supporters of each approach contend their preferred approach most accurately captures marginal capital related customer cost. We find that neither side fully validates the use of its preferred model but rather focuses on invalidating the opposing model. Hence, we are left with two imperfect models. However, in looking at the results of the models, we find the Rental Method results in costs that are fair across the customer classes, as seen in Tables 11 and 12 below.[6]

[4] D.20-02-045, p. 49.

[5] *Id.*, p. 50 (citations omitted).

[6] *Id.*, pp. 50-51.

As stated above, SDG&E recommends that the appropriate marginal distribution customer cost methodology to adopt in this proceeding should be based on the evidence presented in this proceeding, which supports the use of the Rental Method. Recent CPUC precedent also supports adoption of the Rental Method, in D.20-02-045, which adopted the Rental Method over the NCO Method to calculate marginal distribution customer costs.

2. Rental Method is a Better Proxy for Marginal Cost than the NCO Method

Both Cal Advocates and TURN argue that the NCO Method is a better proxy for marginal costs than the Rental Method. Cal Advocates tries to argue that the NCO Method is a better proxy for marginal cost because the NCO Method only considers the costs of TSM hookups for forecasted new customers while the Rental Method overstates the cost at which customers, if given the option, could purchase the TSM equipment themselves because it assigns a hypothetical rental value based on the cost of TSM hookups to all customers.[7] TURN argues that the Rental Method focuses more on embedded investments and thus captures more average costs rather than marginal costs.[8]

Cal Advocates is mistaken in stating that the Rental Method assigned a hypothetical rental value to TSM equipment. Actually, the Rental Method calculated a rental price based on the incremental TSM costs (not hypothetical or 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 two marginal distribution customer cost methodologies is the conversion of the incremental TSM costs into a cost per customer

[7] Cal Advocates Amended Prepared Testimony, pp. 1-6 – 1-7.
[8] TURN Prepared Testimony, pp. 5-8.

amount. The Rental Method, using the Real Economic Carrying Charge ("RECC") factors to annualize the cost of TSM assets, correctly reflects the marginal distribution customer cost of providing service to the next customer and correctly applies these marginal costs to all customers taking electric service from SDG&E. Conversely, the NCO Method does not calculate the marginal distribution 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. The NCO Method applies the Present Value Revenue Requirement ("PVRR") factors to the TSM costs to determine the present value of the revenue requirements for the life of the TSM assets, multiplies that value by the forecasted growth rate in the customer class to calculate the TSM marginal costs for new customers in that class, and then divides that amount by all customers in that customer class. Given the NCO Method's dependency on the customer growth rate by customer class, a growth rate that has no relationship to the cost of TSM assets, the NCO Method does not accurately reflect marginal costs. Contrary to what Cal Advocates claims, the Rental Method does not overstate the TSM costs but actually properly calculates TSM marginal costs and the resulting TSM rental price needed to decide whether to connect to the SDG&E electric grid; whereas the NCO Method does not properly calculate the TSM marginal cost and thus does not provide customers with an accurate opportunity cost to connect to the SDG&E electric grid.

The following example demonstrates how the NCO Method dependency on customer class growth rates result in a flawed TSM price signal. Assume you have two customers taking service using the same TSM assets, but the customers are in different customers classes, with one class having a higher forecasted customer growth rate than the other class. The customer class having the higher customer growth rate would have a higher marginal TSM cost under the NCO Method. This demonstrates one of the flaws in the NCO Method, since the TSM marginal costs for both customers would be different because of differences in the customer class growth rates of the two customers and not because of any differences in the TSM costs needed to serve the customers. If we instead use the Rental Method, the TSM marginal costs for both customers would be identical, as they should be, since the TSM costs to serve the two customers are exactly the same.

TURN appears to misunderstand the difference between marginal and embedded costs.[9] Marginal customer costs reflect the incremental costs to serve the next customer whereas embedded customer costs reflect the historical costs incurred to serve customers. 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. As mentioned above, the NCO and Rental methods use the same incremental TSM costs in the development of marginal distribution customer costs. The difference in these two methodologies is how these incremental costs are converted to a marginal distribution customer cost. SDG&E believes that the Rental Method properly calculates the marginal distribution customer cost by customer class to provide service to the next customer; whereas the NCO Method fails to do this because it calculates the incremental change in total forecasted customer costs due to the expected customer growth rate of each customer class.

For these reasons, contrary to Cal Advocates' and TURN's claims, the Rental Method properly calculates marginal distribution customer costs, and the NCO Method is

[9] *Id.*, p. 5.

the marginal distribution customer cost methodology that does not properly calculate the marginal costs of the TSM assets for the next customer requiring service.

3. Use of Customer Class Growth Rate in NCO Method Demonstrates a Clear Flaw in the Methodology

Cal Advocates' argument against SDG&E's criticism of using the customer growth rate in the NCO Method is that the growth rate is not intended to have a relationship to the cost of serving an individual customer but is only intended to properly allocate the TSM costs for new customers to the correct customer classes.[10]

This argument is confusing, however, because the purpose of a marginal cost methodology is to properly calculate the cost to serve an individual customer. Cal Advocates states that "[m]arginal customer access costs (MCAC) represent the incremental costs of providing a new customer access to the electric grid,"[11] which clearly implies that the marginal customer cost methodology adopted needs to correctly calculate the cost of serving an individual customer. The marginal distribution customer costs developed in GRC Phase 2 proceedings serve two purposes. First, these marginal distribution customer costs are used to allocate distribution revenues to customer classes. Second, these marginal distribution customer costs are used to develop the distribution customer charges (also called basic service fees) billed to some customers to recover marginal distribution customers costs. Cal Advocates seems to justify the use of the NCO Method based solely to allocate distribution revenues and not for setting distribution customer charges. However, as SDG&E explains in Section II.A.4 below, the NCO Method also fails to properly allocate

[10] Cal Advocates Amended Prepared Testimony, pp. 1-9 and 1-10.
[11] *Id.*, p. 1-1 (citation omitted).

distribution revenues to customer classes and thus, the NCO Method fails to serve either purpose of developing marginal distribution customer costs in this proceeding.

4. Rental Method More Accurately Allocates Authorized Distribution Revenues

Cal Advocates, CALSLA, and TURN argue that the NCO Method appropriately allocates the cost of new TSM connections to customer classes. Cal Advocates argues that the NCO Method mimics the manner that TSM costs are incurred and recovered under the CPUC's line extension rules (Rule 15 and Rule 16) and ensures customer classes will pay the full cost of TSM hook-ups.[12] TURN states that under the NCO Method, the full cost for TSM costs for new connections due to new customers is correctly assigned to the appropriate customer classes and fully recovered in that year. It also states that customers are borrowing from each other, not SDG&E, to pay for TSM connection costs.[13] CALSLA argues that the NCO Method only charges customers for TSM hook-ups once, while the Rental Method overcharges customers over time for these hookups.[14]

SDG&E disagrees with Cal Advocates, CALSLA, and TURN. Contrary to what Cal Advocates states, unlike the Rental Method, the NCO Method is not designed to fully collect TSM hookup costs. The CPUC adopted the concept of TSM allowances under Rules 15 and 16 to collect the TSM costs over the life of the TSM assets from all customers through authorized distribution revenue requirements based on the recovery of TSM allowances. Basically, developers receive an allowance towards the cost of new customer hookups from SDG&E and these hookup costs are then recovered over the life of the TSM assets as part of the authorized distribution revenue requirement adopted for SDG&E in its GRC Phase 1

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[12] *Id.*, pp. 1-4 – 1-5, 1-10 and 1-11.
[13] TURN Prepared Testimony, pp. 8 and 10.
[14] CALSLA Prepared Direct Testimony, p. 4.

proceedings, which is proposed to be allocated 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 TSM allowance recovery methodology because it calculates the TSM marginal costs based on recovery of TSM costs from customers over the life of the TSM assets, which is consistent with how Rule 15 and Rule 16 allowances are recovered. Conversely, the NCO Method calculates marginal costs for TSM assets at a point in time not over the life of the TSM asset. For this reason, contrary to what Cal Advocates claims, the Rental Method (not the NCO Method) is consistent with the CPUC's line extension rules; and thus, the Rental Method (and not the NCO Method) ensures customer classes will pay the full cost of TSM hook-ups.

TURN incorrectly argues that the NCO Method properly recovers the full cost of the TSM costs in that one year and that customers are borrowing from each other to fund the cost of TSM assets. This is not correct. As stated above, the Rule 15 and Rule 16 allowances that SDG&E provides to fund TSM costs is paid for over the life of the TSM assets through the distribution rates SDG&E collects from its customers. Also, TSM costs do reflect costs paid for by SDG&E; and thus, contrary to TURN's argument, customers are borrowing the cost of TSM connections from SDG&E and not from other customers. For this reason, the Rental Method (not the NCO Method) more accurately represents how these costs are actually being recovered from customers because the Rental Method is based on a TSM rental approach reflecting the recovery of these costs over the life of the TSM assets. The fact that TSM costs are recovered over the life of the TSM asset shows the flaw in TURN's argument that the NCO Method accurately reflects the recovery of new TSM customer connections in one year.

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 Cal Advocates, CALSLA, and TURN; but rather the NCO Method understates customer connection costs.[15] 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 to be recovered from customer classes.

5. Fungibility of TSM Assets Not Relevant in Deciding the Appropriate Marginal Customer Cost Methodology

Cal Advocates and CALSLA argue that the Rental Method should not be adopted because they believe that it relies on an impractical deferral concept, claiming that because TSM hookups are not fungible assets, they do not have an opportunity cost value.[16]

SDG&E disagrees that the salvage value argument is important in deciding the appropriate marginal distribution customer cost methodology to use in this proceeding; and regardless, the argument that TSM assets have little or no value once installed is incorrect. Smart meters have undeniable value because meters can be moved if a customer discontinues service with SDG&E. But more importantly, final line transformers, that

[15] Cal Advocates Amended Prepared Testimony, p. 1-7; CALSLA Prepared Direct Testimony, p. 4; and TURN Prepared Testimony, pp. 5-10.
[16] Cal Advocates Amended Prepared Testimony, pp. 1-4, 1-8 and 1-9; and CALSLA Prepared Direct Testimony, p. 4.

reflect the majority of TSM costs, are generally installed to serve more than one customer (i.e., the smallest single-phase and three-phase final line transformers are assumed to serve 22 and 60 residential customers, respectively). A decrease in one customer would free up capacity on the final line transformer to serve other customers; and thus, final line transformers clearly have value after installation. 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 in Sections II.A.2 through II.A.4, marginal distribution customer costs based on the Rental Method rather than the NCO Method provide more accurate price signals regarding marginal distribution customer costs and more accurately allocate authorized distribution revenues to customers.

B. Exclusion of Final Line Transformers from Distribution Costs

TURN recommends that marginal distribution customers costs should reflect the costs under the "Basic Customer Method" and not costs under the "TSM Method." The difference in these two methods is that the "Basic Customer Method" does not include final line transformer costs, like in the "TSM Method." TURN argues that final line transformers should not be included in marginal distribution customer costs because in reality not all new residential connections require a new final line transformer to be installed.[17]

SDG&E disagrees with TURN that the cost of final line transformers should not be included in marginal distribution customer costs. The CPUC has adopted the inclusion of final line transformers, service drops, and meters in marginal distribution customer costs because these costs reflect facilities costs required to serve an individual customer. While a final line transformer may serve more than one customer, the cost of this transformer has

[17] TURN Prepared Testimony, pp. 10-13.

been determined to be customer-related and thus included in marginal distribution customer costs. TURN argues for the exclusion of final line transformer costs because these costs might be shared by other customer; and if shared, a new transformer might not be needed to serve a new residential connection, if the existing transformer has kW capacity availability. This a flawed argument because a customer's ability to receive service on an existing final line transformer does not change the fact that a transformer is required to serve the customer. This is the reason that the Rental Method is appropriate because it calculates the marginal distribution customer costs to serve all customers. There is thus no need or reason to consider capacity availability on final line transformers because the full cost of a shared transformer is properly allocated to customers. For this reason, SDG&E recommends that the CPUC reject TURN's proposal to replace the long-standing use of TSM costs in the calculation of marginal distribution customer costs.

C. Shared Service Drop Costs

UCAN states that service drops used to serve multi-family apartments and some small commercial customers located in strip malls might reflect one service drop to serve more than one customer. UCAN argues that, because SDG&E's service drop costs assume a service drop is needed for every customer and UCAN assumes that shared service drop costs will have a lower cost per customer, SDG&E should update its marginal distribution customer cost calculation to reflect shared service drops.[18]

UCAN is correct that a small number of SDG&E's residential and small commercial customers take service on shared service drops. SDG&E calculation of service drop costs has always assumed one service drop for each customer and thus, SDG&E currently does

[18] UCAN Direct Testimony, pp. 37-40.

not have the full set of data needed to calculate costs for shared service drops. UCAN assumes that service drop costs will be less for customers that share service drops, which may or may not be correct, because service drops that are shared would require higher cost wire types and more wire runs. In fact, based on a small sample of recent SDG&E multi-family projects the shared service drop cost per customer for these projects are significantly higher than the residential average service drop cost per customer that SDG&E calculated in this proceeding. For this reason, SDG&E recommends that the CPUC adopt the service drop costs proposed by SDG&E in this proceeding and recommend that SDG&E work with UCAN prior to its next GRC Phase 2 proceeding to figure out the best way to address UCAN's concern about shared service drop costs based on the data available.

D. Inclusion of TSM Replacement Costs in New Customer Only ("NCO") Method Calculations

Cal Advocates proposes the exclusion of TSM replacement costs in the calculation of marginal distribution customer costs using the NCO Method because it believes TSM replacement costs are not technically marginal costs. To account for replacement costs, Cal Advocates proposes to scale up the present value of the revenue requirements for new hookups to account for replacements.[19]

SDG&E disagrees with Cal Advocates' proposal. TSM replacement costs need to be included in the NCO Method because replacement of TSM equipment results in a real cost that should be included in the calculation of marginal customer costs based on the NCO Method. Cal Advocates states that "[r]eplacement costs are much more closely connected to the service lives of the equipment and to environmental factors than to customer

[19] Cal Advocates Amended Prepared Testimony, p. 1-12.

behavior."[20] Cal Advocates is correct that TSM replacement costs are tied to the life of the asset that needs to be replaced. This is the reason that replacement costs need to be included in the NCO Method calculation because, unlike the Rental Method, the NCO Method does not take into account the life of the asset. Cal Advocates implies that SDG&E is being inconsistent because it did not include replacement costs in its marginal distribution demand calculations.[21] What Cal Advocates fails to understand is that just like the Rental Method, SDG&E's marginal distribution demand costs are based on RECC factors that calculate costs based on the life of the demand asset; and thus, replacement costs are already factored into SDG&E's distribution demand cost calculation. For this reason, if the CPUC ultimately adopts the use of the NCO Method to calculate marginal distribution customer costs in this proceeding, SDG&E recommends that the CPUC reject Cal Advocates' proposal to exclude TSM replacement costs from the NCO Method calculation and adopt the TSM replacement rate proposed by SDG&E.

E. 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 prepared rebuttal testimony, as presented in Attachment A, reflect the adjustments to the GP, WC, and A&G load factors, as proposed by Cal Advocates and described in Section III.D below. SDG&E recommends that the CPUC adopt SDG&E's proposed marginal distribution customer costs based on the Rental Method, updated to reflect the adjustments to the load factors, as presented in Attachment A.

[20] *Id*.
[21] *Id*.

F. Revised Illustrative Marginal Distribution Customer Costs Based on the NCO Method

As stated above in Section II.A, SDG&E disagrees with the use of the NCO Method to calculate marginal distribution customer costs in this proceeding and recommends that the CPUC adopt SDG&E's proposed updated marginal distribution customer costs based on the Rental Method, as presented in Attachment A. However, if the CPUC decides to adopt the NCO Method for allocating marginal distribution customer costs in this proceeding, the CPUC should adopt the revised illustrative NCO results calculated by SDG&E, updated to reflect the adjustments to the load factors described in Section III.D, as presented in Attachment C.

III. MARGINAL DISTRIBUTION DEMAND COSTS

A. Reassigning Distribution Capital Costs

Cal Advocates has recategorized some of the distribution capital costs expenditures identified in SDG&E's GRC Phase 1 proceedings to different cost categories on the belief that SDG&E has understated the costs that are capacity-related.[22] SEIA agrees with Cal Advocates' reassignment of distribution capital costs based on its opinion that it is important to use a broader set of distribution investments in the marginal distribution demand regression analysis whose principal or stated purpose may not be distribution capacity-related to calculate marginal distribution demand costs.[23]

SDG&E disagrees with SEIA that the distribution demand costs used in the regression analysis to calculate marginal distribution demand costs should include more than distribution capacity-related costs. The purpose of calculating marginal distribution demand

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[22] *Id.*, pp. 2-3, 2-9 – 2-14.
[23] SEIA Prepared Direct Testimony, p. 10.

costs is to determine the costs per kW to expand facilities from the substation to the point of customer access to serve an additional kW of demand. For this reason, the distribution capital costs SDG&E used to calculate marginal distribution demand costs correctly reflects only capacity-related distribution demand costs required to serve an additional kW of customer demand. Thus, SEIA's reasoning for agreeing with Cal Advocates' distribution capital costs reassignment has no merit.

SDG&E's agrees with Cal Advocates' decision to reevaluate the assignment of SDG&E's distribution capital cost expenditures into the various cost categories to ensure the assignments are correct. While SDG&E's agrees with some of the reassignments that Cal Advocates proposed, the majority of these costs were correctly assigned by SDG&E. For instance, Cal Advocates states that budget item 01269.0 in SDG&E's 2019 GRC Phase 1 assigned as reliability-substation should be reassigned as capacity-substation because the business purpose of this cost item is to expand the capacity on the substation.[24] Cal Advocates is correct that the distribution capital additions will expand the capacity on the substation but the capacity is being expanded to meet the reliability needs of existing customer demand on the substation and not to meet an increase in customer demand on the substation. Therefore, Cal Advocates is incorrect when it states that the 01269.0 distribution capital costs should be reassigned to capacity-substation. However, Cal Advocates is correct when it pointed out that budget item 06129.0 was mislabeled as reliability-substation costs when it should have been labeled capacity-substation costs.[25] The 06129.0 distribution capital costs meet both reliability and capacity needs and thus, at least part of the cost driver for these costs is to meet increases in customer demand on the substation. For this reason,

[24] Cal Advocates Amended Prepared Testimony, pp. 2-9 – 2-10.
[25] *Id.*, p. 2-10.

SDG&E agrees with Cal Advocates' proposal to reassign the costs for budget item 06129.0 from reliability-substation to capacity-substation. One of the main cost categories that Cal Advocates incorrectly proposed to reassign to capacity-related costs is "New Business-Demand" costs. While "New Business-Demand" costs reflect demand-related costs, these costs are not associated with adding capacity to meet demand needs of new customers as Cal Advocates assumes. Any costs associated with adding capacity to meet demand needs of new customers has already been included in the capacity cost category. Therefore, "New Business-Demand" costs should not be reclassified as capacity-related costs, as Cal Advocates proposes.

Attachment D presents all the budget items that Cal Advocates proposed to be reassigned to different cost categories and SDG&E's position on these reassignments. The updated proposed marginal distribution demand costs presented in Attachment A, and the resulting distribution revenue allocations and rates based on those updated proposed marginal distribution demand costs presented in Attachment B, reflect the budget items that SDG&E agrees with Cal Advocates should be reassigned, as presented in Attachment D.

B. Requirement to Track Actual Distribution Capital Expenditures

Cal Advocates proposes that the CPUC require SDG&E to adopt an accounting method to track actual historic distribution capital spending, in order to identify the capacity costs associated with actual distribution capital spending for use in SDG&E GRC Phase 2 proceedings.[26]

SDG&E agrees with Cal Advocates that if actual cost data is available, the capacity costs used to develop marginal distribution demand costs should be based on actual

[26] *Id.*, pp. 2-2 and 2-15.

distribution capital spending costs. Pursuant to D.14-12-025 and as further amended by D.19-04-020, SDG&E is currently required to submit Risk Spending Accountability Reports annually that provide actual expenditures, which includes electric distribution capital expenditures. This reporting requirement has allowed SDG&E to determine the capacity-related portion of the total distribution capital expenditures since 2017. At the time of SDG&E's 2019 GRC Phase 2 filing on March 4, 2019, SDG&E only had the actual distribution capital expenditure data for 2017, which is why SDG&E proposed that marginal distribution demand costs continue to rely on forecasted rather than actual distribution capital cost data. However, SDG&E's 2019 Spending Accountability Report was submitted on March 31, 2020, and thus, SDG&E now has 2017-2019 actual total distribution capital cost data that can be used in the calculation of its proposed marginal distribution demand costs. Attachment E provides the feeder and local distribution ("FLD") and substation capacity-related costs and resulting capacity-related percentages for 2017-2019, based on the updated forecasted distribution capital cost assignments agreed to by SDG&E, as described in Section III.A above, compared with the costs and resulting percentages based on actual SDG&E distribution capital expenditures. SDG&E proposes that the CPUC adopt the use of the FLD and substation capacity-related costs and resulting capacity-related percentages for 2017-2019, based on actual SDG&E distribution capital expenditures. The updated proposed marginal distribution demand costs presented in Attachment A, and the resulting distribution revenue allocations and rates based on those updated proposed marginal distribution demand costs presented in Attachment B, reflect the updated FLD and substation capacity-related costs and percentages based on actual distribution capital expenditures for years 2017-2019.

C. Modifications of Capacity Cost Formulas to Reflect Capacity-Related Easement and Overhead Pools Costs

Cal Advocates proposed modifications to the formulas used to determine the portion of the distribution easement and overhead pools costs that are capacity-related. Cal Advocates states that its formulas more accurately track and allocate easement and overhead pools costs to the FLD and substation capacity-related costs.[27]

SDG&E disagrees with Cal Advocates' proposed modifications to the formulas SDG&E is using to calculate the capacity-related portion of its distribution easement and overhead pools costs. SDG&E's formulas correctly allocate easement and overhead pool costs to FLD and substation capacity-related costs by calculating the appropriate allocation factors by dividing the easement costs and overhead pool costs over the total applicable costs that these costs should be allocated to, and then multiplying these allocation factors by the FLD and substation capacity costs. Cal Advocates' formulas incorrectly calculate the easement and overhead pools costs to be allocated to easement and overhead pools costs and not allocated to FLD and substation capacity costs. However, SDG&E does agree with Cal Advocates that SDG&E's formulas do not clearly identify the easement and overhead pool costs that are being allocated to capacity-related costs because the formulas combine the allocated easement and overhead pool costs with the capacity-related costs. For this reason, the Chapter 5 marginal distribution demand cost rebuttal workpapers ("Ch_5_WP#4_Marg Dist Demand Cost_Rebuttal") break out the allocation of the easement and overhead pool costs separately to clearly identify the allocated easement and overhead pool costs to capacity-related costs in the formulas. Because SDG&E's formulas properly allocate easement and overhead pool costs to FLD and substation capacity-related costs, SDG&E

[27] *Id.*, pp. 2-10 – 2-11.

recommends that the CPUC reject Cal Advocates' proposal to modify the formulas to calculate the allocation of easement and overhead pools costs to FLD and substation capacity-related costs.

D. Modification to General Plant ("GP"), Working Capital ("WC"), and Administrative & General ("A&G") Load Factors

Cal Advocates proposes to modify the calculation of the GP, WC, and A&G load factors used to calculate marginal distribution demand costs in this proceeding. Cal Advocates proposes to change the calculation of GP and A&G load factors to reflect a 3-year average instead of a 5-year average of appropriate costs to better reflect recent trends in costs, and to include 2018 Federal Energy Regulatory Commission ("FERC") Form 1 costs in the average calculation (average of 2018-2016 costs). In addition, Cal Advocates proposes to change the WC load factor calculation to reflect data from SDG&E's two most recent GRC Phase 2 proceedings (SDG&E 2019 GRC Phase 2 and SDG&E 2016 GRC Phase 2) instead of the most recent three GRC Phase 2 proceedings, as SDG&E proposed, which also included the WC load factor calculation from the SDG&E 2012 GRC Phase 2.[28]

SDG&E accepts Cal Advocates' proposal to change the number of years used to develop the GP and A&G load factors from a 5-year average to a 3-year average approach. SDG&E based the calculation of these loaders on a 5-year average of costs because using five years of data insures that one year of data does not overly influence the results of the loaders. However, SDG&E agrees with Cal Advocates that recent trends in costs support using a 3-year average to develop these load factors in this GRC Phase 2 proceeding. SDG&E also agrees with Cal Advocates' proposal to include 2018 FERC Form 1 cost data in the GP and A&G load factor calculations. When SDG&E originally filed its 2019 GRC

[28] *Id.*, pp. 2-12 – 2-13.

Phase 2 testimony on March 4, 2020, SDG&E's 2018 FERC Form 1 cost data was not available, which is the reason that the 2018 cost data was not used in the calculation of the GP and WC load factors. But SDG&E agrees that since the 2018 cost data is now available, it should be used in the calculation of the GP and WC load factors.

SDG&E also agrees with Cal Advocates' proposal to base the WC load factor calculations on only the average of the 2019 GRC Phase 2 and 2016 GRC Phase 2 WC calculations, which would eliminate the 2012 GRC Phase 2 WC calculation from the WC load factor calculation. For the above reasons, SDG&E recommends that the CPUC adopt the GP, WC, and A&G load factors proposed by Cal Advocates that are used in the calculation of SDG&E's proposed marginal distribution demand costs and marginal distribution customer costs, as presented in Attachment A, and used to develop the distribution revenue allocations, as presented in Attachment B.

E. Modification to Calculation of Fixed Operation & Maintenance ("O&M") Overhead Cost

Cal Advocates proposes modifications to the calculation of the Fixed O&M Overhead Cost included in the calculation of the marginal distribution demand costs. Specifically, Cal Advocates proposes that the calculation of the Fixed O&M Overhead Cost should be based on a 3-year average of FERC Form 1 costs and include 2018 FERC Form 1 cost data (2016-2018 average), just like the calculation of the GP and A&G load factors. Cal Advocates also proposes to start the escalations from 2018 instead of 2016 and to base the calculations on the demand and customer cost allocation factors, as presented in SDG&E's prepared direct testimony.[29]

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[29] *Id.*, p. 2-9, Table 2-6, and Chapter 2 Workpapers, "O&M Cost-Calcs" tab.

Consistent with the GP and A&G load factors, SDG&E agrees with changing the approach for the calculation of the Fixed O&M Overhead Cost in this GRC Phase 2 proceeding from a 5-year to 3-year average and including 2018 FERC Form 1 cost data in the calculation of the Fixed O&M Overhead Cost (2016-2018 average). SDG&E also accepts Cal Advocates' proposal to base the escalation from a starting point of 2018 rather than 2016. This escalation change does not change the calculation because SDG&E and Cal Advocates are using the same escalation factors to escalate the costs.

However, Cal Advocates' Fixed O&M Overhead Cost calculation is mistakenly based on the distribution O&M customer and demand allocation factors from SDG&E's 2019 GRC Phase 2 Direct Testimony instead of the O&M customer and demand allocation factors from SDG&E's 2019 GRC Phase 2 Second Revised Direct Testimony. SDG&E's Second Revised Direct Testimony (submitted on January 15, 2020) describes a proposed change in how it allocates unassigned distribution O&M costs based on the location of the cost performed rather than the percentage of SDG&E's distribution plant that is demand-related versus customer-related, as proposed by Cal Advocates and agreed to by SDG&E in SDG&E's 2018 Rate Design Window ("RDW") proceeding.[30] This change in the allocation of unassigned distribution O&M costs also revises the calculation of the Fixed O&M Overhead Cost to no longer be based on distribution plant allocation factors. For this reason, the CPUC should approve Cal Advocates' proposed modification to the Fixed O&M costs used in the calculation of marginal distribution demand costs with one modification, to correctly assign these costs based on customer and demand allocation factors that SDG&E

[30] Chapter 5 Second Revised Prepared Direct Testimony of William G. Saxe on Behalf of San Diego Gas & Electric Company (January 15, 2020), pp. WGS-9 – WGS-10.

proposed. The updated marginal distribution demand costs, presented in Attachment A, reflect the revised Fixed O&M Overhead Cost.

F. NERA Regression Analysis Appropriate Methodology to Calculate Marginal Distribution Demand Costs

UCAN raises concerns regarding the use of the NERA regression analysis to calculate marginal distribution demand costs considering the fact that SDG&E has been experiencing sales declines recently. UCAN recommends that SDG&E review other marginal distribution demand cost methodologies or even embedded cost methods for use in future GRC Phase 2 proceedings.[31]

While the sales decline concern that UCAN raises is a valid concern, SDG&E still believes that the NERA regression analysis is the most appropriate methodology to use to calculate marginal distribution demand costs in this proceeding. The negative sales issue that UCAN raises was a concern that SDG&E raised in its 2016 GRC Phase 2 rebuttal testimony, when it decided to switch from using actual distribution loads to using distribution planning forecasted circuit and substation loads in its marginal distribution demand cost regression analysis, partially because using actual loads could result in annual negative incremental loads that could lead to negative marginal distribution demand costs.[32] As stated in that 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. 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

[31] UCAN Direct Testimony, pp. 12-14.

[32] A.15-04-012, 2016 GRC Phase 2, Prepared Rebuttal Testimony of William G. Saxe on Behalf of San Diego Gas & Electric Company in Support of Second Amended Application, Chapter 5 (August 30, 2016) (Exhibit No. SDG&E-15), pp. WGS-34 – WGS-35.

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.[33]

SDG&E believes that by switching from the use of actual distribution loads to forecasted distribution planning loads in the marginal distribution demand cost regression analysis, SDG&E has mitigated the sales decline concern that UCAN raises. However, SDG&E is always open to discussing and looking at the use of other methodologies that other parties believe could add value to the calculation of marginal distribution demand costs in future SDG&E GRC Phase 2 proceedings, as UCAN suggests.

G. Requirement that SDG&E Analyze How Distribution Investment and Resulting Distribution Load were Impacted by Installed Energy Efficiency and Behind-The-Meter ("BTM") Photovoltaics (PV") in Future GRC Proceeding.

Cal Advocates argues that SDG&E's use of forecasted historical distribution load instead of actual historical distribution load in the marginal distribution demand cost regression analysis results in marginal costs that are not real. Cal Advocates proposes that SDG&E be required to analyze the impact of BTM PV and energy efficiency load and how the BTM load should be reflected in the load data used in marginal distribution demand calculations in future GRC Phase 2 proceedings.[34]

SDG&E disagrees with Cal Advocates that the use of the distribution planning forecasted loads in the marginal distribution demand cost regression analysis results in inaccurate marginal costs. Actually, just the opposite is true. As explained above in Section III.F, SDG&E switched from using actual distribution historical loads to using distribution planning forecasted loads in the marginal distribution demand calculation because the

[33] *Id*., p. WGS-34 (citation omitted).
[34] Cal Advocates Amended Prepared Testimony, pp. 2-2 and 2-12.

distribution planning forecasted loads drive SDG&E's distribution capital expenditure needs. For this reason, contrary to Cal Advocates' argument, the use of SDG&E's distribution planning forecasted loads in the development of marginal distribution demand costs results in accurate marginal distribution demand cost calculations. In addition, SDG&E's distribution planning forecasted loads reflect the effects from installed Distribution Energy Resources ("DER") such as energy efficiency and BTM PV. Thus, contrary to Cal Advocates' assumption, SDG&E's distribution planning forecasted loads already reflect the impacts from energy efficiency and BTM PV. For this reason, Cal Advocates' proposal to require SDG&E to analyze the impact of installed energy efficiency and BTM load on SDG&E's distribution load in marginal distribution demand calculations in future GRC Phase 2 proceedings is not needed and should not be adopted by the CPUC.

H. Time-Varying Distribution Marginal Costs

SDAP recommends that SDG&E be required to develop time-varying distribution marginal costs for use in CTM analyses.[35]

SDG&E already develops time-varying distribution marginal costs that can be used in CTM analyses, as SDAP proposed. The majority of SDG&E's distribution costs are not time-variant because most distribution costs are either based on the number of customers and the cost of the facilities to serve those customers (marginal distribution customer costs), or marginal distribution demand costs based on the customer's maximum demand regardless of when the demand is used (non-coincident distribution demand costs). However, a small portion of SDG&E's marginal distribution demand costs reflect peak demand costs that are based on demand used during the hours of 4 p.m. to 9 p.m. and thus reflect marginal

[35] SDAP Opening Testimony, pp. 8-9, 11-12, and 43-44.

distribution demand costs that are time-variant. For this reason, the CPUC should disregard SDAP's request for SDG&E to be required to develop time-varying distribution marginal costs because SDG&E marginal distribution costs already reflect the portion of these costs that is time-varying.

I. SDG&E Proposed Updated Marginal Distribution Demand Costs

SDG&E's proposed updated marginal distribution demand costs based on the NERA regression analysis in this rebuttal testimony, as shown in Attachment A, reflect the following adjustments: (a) reassignment of distribution capital costs proposed by Cal Advocates and agreed to by SDG&E, as described in Section III.A above and presented in Attachment D; (b) update of distribution capacity costs to reflect actual SDG&E distribution capital expenditures, as described in Section III.B above and presented in Attachment E; and (c) adjustments to the GP, WC, and A&G load factors, as proposed by Cal Advocates, as described in Section III.D above. SDG&E recommends that the CPUC adopt SDG&E's proposed updated marginal distribution demand costs updated to reflect these adjustments, as presented in Attachment A.

IV. DISTRIBUTION REVENUE ALLOCATION

A. Marginal Distribution Demand Costs ("MDDC") are Scaled Correctly

Cal Advocates states that SDG&E did not scale the MDDC correctly in the distribution revenue allocation calculation.[36] This statement appears to be based on a misunderstanding of how SDG&E calculated the MDDC in its workpapers. SDG&E calculated the total amounts for substations and FLD by multiplying the proposed marginal demand costs by the applicable 2020 distribution planning forecasted load, just as Cal

[36] Cal Advocates Amended Prepared Testimony, pp. 4-5 and 4-6.

Advocates did. For this reason, there is not a MDDC scaling issue in SDG&E's distribution revenue allocation, as Cal Advocates claims, because SDG&E uses the same scaling method of the MDDC as Cal Advocates. The only reason Cal Advocates and SDG&E derive different scaling results is because of the differences between Cal Advocates and SDG&E proposed marginal distribution substation and FLD demand costs used in the scaling calculations.

B. Distribution Revenue Allocation

Cal Advocates proposed a distribution revenue allocation based on the marginal customer and demand costs it proposed.[37] SDG&E disagrees with the distribution revenue allocations proposed by Cal Advocates because of its disagreement with Cal Advocates' proposed adjustments to the marginal distribution customer and demand costs, as described in Sections II and III of this testimony above. The distribution revenue allocations that SDG&E calculates, as presented in Attachment B.2, are the correct distribution revenue allocations based on the SDG&E proposed updated marginal distribution customer and demand costs.

C. SDG&E's Updated Distribution Revenue Allocation

Attachment B presents the updated Equal Percent of Marginal Costs ("EPMC") distribution revenue allocation based on the current distribution revenues reflected in rates effective January 1, 2020. This updated EPMC distribution revenue allocation is based on the SDG&E proposed updated marginal distribution customer and marginal distribution demand costs in this prepared rebuttal testimony, as addressed above and presented in Attachment A. The SDG&E updated distribution revenue allocation is presented in

[37] *Id.*

Attachment B. Attachment B.1 presents the distribution marginal cost allocation factors by customer class. Attachment B.2 presents the allocation of distribution revenues to each customer class based on the proposed distribution marginal cost allocations factors. Attachment B.3 presents the resulting distribution EPMC rates and revenues by customer class. However, in the interest of promoting rate stability SDG&E did not propose updating its distribution revenue allocation based on the revenue allocations presented in Attachment B.2 but rather proposed to continue the current distribution revenue allocation adopted in D.17-08-030, as discussed in the prepared rebuttal testimony of SDG&E witnesses Jeff P. Stein (Chapter 1) and Neetu Malik (Chapter 2).

V. DISTRIBUTION DEMAND CHARGE STUDY

A. Effects of Capacity Factors Are Not Double Counted

Cal Advocates, TURN, and SEIA claim that SDG&E double counts the effects of capacity factors in the determination of the annual distribution capital investments in the distribution grid that are caused by load growth. Cal Advocates claims that SDG&E uses a two-step process to determine the percentage of distribution demand costs that should be recovered in on-peak demand charges, when actually the first step can be deleted because this step duplicates the second step and thus, understates the portion of the costs that are on-peak related.[38] TURN and SEIA concur with Cal Advocates' claim.[39]

SDG&E disagrees with Cal Advocates, TURN, and SEIA that it is double counting the effects of the capacity factors in determining the percentage of distribution demand costs that is on-peak related. Actually, the two steps that Cal Advocates describes are needed to

[38] *Id.*, pp. 7-2, 7-4 – 7-6.
[39] TURN Prepared Direct Testimony, pp. 16-17; and SEIA Prepared Direct Testimony, p. 22.

determine what portion of distribution costs is on-peak related. The first step determines the percentage of SDG&E's distribution demand costs that is capacity-related by developing distribution capacity factors. The second step determines the percentage of the distribution capacity-related costs that is on-peak related by multiplying these capacity factors by the percentage of the substation and FLD capacity costs associated with the 4 p.m. to 9 p.m. on-peak period. Cal Advocates, TURN, and SEIA appear to be confused over the need to use the capacity factors in the determination of the on-peak demand related costs, which is needed because only SDG&E capacity-related distribution demand costs are on-peak related. While SDG&E's distribution data shows that 66.3% of distribution circuits and 72.1% of substations peak during the 4 p.m. to 9 p.m. on-peak period, these percentages now need to be multiplied by the capacity factors to determine the percentage of SDG&E distribution costs that should be recovered through on-peak demand charges. For this reason, Cal Advocates, TURN, and SEIA are mistaken when they claim that SDG&E is understating the on-peak related distribution costs by double counting the distribution capacity factors.

B. Non-Coincident Distribution Demand Costs Vary with Customer Maximum Demand

SBUA states that the only costs that vary with a customer's maximum demand are costs associated with TSM facilities dedicated to that customer.[40] SBUA's statement is incorrect. A significant portion of SDG&E's costs vary with a customer's maximum demand. SDG&E non-coincident distribution and transmission costs reflect costs to meet the maximum demand of a customer regardless of when that demand is used in order to provide reliable electric service. Also, the TSM facilities initially installed to provide

[40] SBUA Direct Testimony, p. 8.

electric service to a customer are designed based on the assumed maximum demand of the customer. However, changes in a customer's maximum demand over time does not impact the TSM costs unless the customer's demand increases significantly, requiring an upgrade to the TSM facilities serving the customer.

VI. SUMMARY AND CONCLUSION

For the reasons stated above, the CPUC should adopt: (a) SDG&E's proposed updated marginal distribution customer costs based on the Rental Method, as described in Section II above and presented in Attachment A; (b) SDG&E's proposed updated marginal distribution demand costs based on the NERA regression analysis, as described in Section III above and presented in Attachment A; and (c) SDG&E's updated distribution revenue allocation calculation based on SDG&E's proposed updated marginal distribution customer and demand costs, as described in Section IV above and presented in Attachment B. However, as stated in Section IV.C above, SDG&E is not proposing to change its current distribution revenue allocation.

This concludes my prepared rebuttal testimony.

ATTACHMENT A

MARGINAL DISTRIBUTION COSTS

ATTACHMENT A - REBUTTAL

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2019 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-002
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)		$135.17			2
3						3
4	Small Commercial ($/Customer/Year)					4
5		0 - 5 kW	$183.77	$460.52		5
6		>5 - 20 kW	$368.07	$460.52		6
7		>20 - 50 kW	$895.19	$460.52		7
8		>50 kW	$1,349.36	$593.64		8
9						9
10	Medium/Large Commercial & Industrial ($/Customer/Year)					10
11		≤500 kW	$1,824.51	$901.44	$6,365.72	11
12		500 - 12 MW	$4,382.02	$998.52	$9,453.44	12
13		> 12 MW		$1,278.32	$13,590.24	13
14						14
15	Agricultural ($/Customer/Year)					15
16		≤20 kW	$376.07	$572.54		16
17		>20 kW	$1,281.75	$660.05		17
18						18
19	Lighting ($/Lamp/Year)		$7.69			19
20						20
21	School					21
22		Non-Lighting ($/Customer/Year)				22
23		≤20 kW	$432.97	$572.54		23
24		>20 kW	$2,092.99	$895.82		24
25						25
26		Lighting ($/Lamp/Year)	$7.69			26
27						27
28	Demand-Related Marginal Cost:					28
29	Feeders & Local Distribution Demand ($/kW/Year)		$57.63	$57.63		29
30						30
31	Substation Demand ($/kW/Year)		$25.06	$25.06		31
32						32
33	Total Demand-Related Marginal Cost ($/kW/Year)		$82.69	$82.69		33

Note: **Customer, Feeder & Local Distribution Demand and Substation Demand Unit Marginal Costs**: Customer, Feeder & Local Distribution Demand and Substation Demand Unit Marginal Costs are from the rebuttal testimony workpapers of SDG&E witness William G. Saxe (Chapter 5).

ATTACHMENT B

DISTRIBUTION REVENUE ALLOCATION

ATTACHMENT B.1 - REBUTTAL

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2019 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-002
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	$178,127	66.6%	$196,400	41.5%	$374,526	50.6%	1
2								2
3	Small Commercial	$44,911	16.8%	$60,124	12.7%	$105,035	14.2%	3
4								4
5	Medium/Large Commercial & Industrial	$38,406	14.4%	$200,066	42.3%	$238,472	32.2%	5
6								6
7	Agricultural	$2,395	0.9%	$6,481	1.4%	$8,876	1.2%	7
8								8
9	Lighting	$1,238	0.5%	$1,013	0.2%	$2,250	0.3%	9
10								10
11	School	$2,229	0.8%	$8,814	1.9%	$11,043	1.5%	11
12								12
13	System	$267,305	100.0%	$472,898	100.0%	$740,203	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 - REBUTTAL

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2019 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-002
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	50.60%		$796,311	$796,311	50.12%	$702,272	13.39%	$771,662	3.19%	1
2											2
3	Small Commercial	14.19%		$223,324	$223,324	14.06%	$250,683	-10.91%	$251,328	-11.14%	3
4											4
5	Medium/Large Commercial & Industrial	32.22%	$11,554	$507,034	$518,588	32.64%	$604,748	-14.25%	$533,843	-2.86%	5
6											6
7	Agricultural	1.20%		$18,871	$18,871	1.19%	$20,765	-9.12%	$19,578	-3.61%	7
8											8
9	Lighting	0.30%	$3,399	$4,785	$8,183	0.52%	$10,342	-20.88%	$12,399	-34.00%	9
10											10
11	School	1.49%	$54	$23,480	$23,534	1.48%	NA	NA	NA	NA	11
12											12
13	System	100.00%	$15,006	$1,573,804	$1,588,811	100.00%	$1,588,811	0.00%	$1,588,811	0.00%	13
14											14
15	Distribution Revenue Requirement ($000):	$1,588,811									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:	$8,048									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, 2020, pursuant to SDG&E Advice Letter 3487-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 $1,588,811,000 Distribution Revenue Requirement reflects the current distribution revenues being collected in rates effective January 1, 2020, pursuant to SDG&E Advice Letter 3487-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 the rebuttal testimony workpapers of SDG&E witness William G. Saxe (Chapter 7).
(6) Non-Marginal Standby Revenues: Standby Revenues of $8,048,000 are the standby revenues based on the forecasted standby determinants multiplied by the applicable current standby rates effective January 1, 2020, pursuant to SDG&E Advice Letter 3487-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, 2020, pursuant to SDG&E Advice Letter 3487-E.

ATTACHMENT B.3 - REBUTTAL

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2019 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-002
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)	$11.26	$23.95		2
3	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)	$1.32	$2.80		3
4	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)	$3.74	$7.94		4
5	Total - Residential			$796,311	5
6					6
7	Small Commercial				7
8	Customer Marginal Cost ($/Customer-Month)				8
9	Secondary				9
10	0 - 5 kW	$15.31	$32.56		10
11	>5 - 20 kW	$30.67	$65.21		11
12	>20 - 50 kW	$74.60	$158.61		12
13	>50 kW	$112.45	$239.08		13
14	Secondary Total	$28.05	$59.64		14
15					15
16	Primary				16
17	0 - 5 kW	$38.38	$81.60		17
18	>5 - 20 kW	$38.38	$81.60		18
19	>20 - 50 kW	$38.38	$81.60		19
20	>50 kW	$49.47	$105.18		20
21	Primary Total	$38.76	$82.41		21
22					22
23	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)				23
24	Secondary	$1.97	$4.19		24
25	Primary	$1.96	$4.17		25
26	Total	$1.97	$4.19		26
27					27
28	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)				28
29	Secondary	$5.06	$10.76		29
30	Primary	$5.03	$10.70		30
31	Total	$5.06	$10.76		31
32					32
33	Total - Small Commercial			$223,324	33
34					34

ATTACHMENT B.3 - REBUTTAL

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2019 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-002
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.
35	Medium/Large Commercial & Industrial				35
36					36
37	Secondary				37
38	≤500 kW	$152.04	$323.27		38
39	500 - 12 MW	$365.17	$776.41		39
40	Secondary Total	$158.19	$336.35		40
41					41
42	Primary				42
43	≤500 kW	$75.12	$159.72		43
44	500 - 12 MW	$83.21	$176.92		44
45	> 12 MW	$106.53	$226.50		45
46	Primary Total	$80.22	$170.56		46
47					47
48	Transmission				48
49	≤500 kW	$530.48	$1,127.89		49
50	500 - 12 MW	$787.79	$1,674.98		50
51	> 12 MW	$1,132.52	$2,407.94		51
52	Transmission Total	$743.34	$1,580.48		52
53					53
54	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)				54
55	Secondary	$2.80	$5.96		55
56	Primary	$2.79	$5.93		56
57	Transmission	$0.00	$0.00		57
58	Total	$2.80	$5.95		58
59					59
60	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)				60
61	Secondary	$7.88	$16.75		61
62	Primary	$7.84	$16.66		62
63	Transmission	$0.00	$0.00		63
64	Total	$7.87	$16.73		64
65					65
66	Total - Medium/Large Commercial & Industrial			$507,034	66
67					67

ATTACHMENT B.3 - REBUTTAL

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2019 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-002
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	$31.34	$66.63		71
72	>20 kW	$106.81	$227.10		72
73	Secondary Total	$50.70	$107.80		73
74					74
75	Primary				75
76	≤20 kW	$47.71	$101.44		76
77	>20 kW	$55.00	$116.95		77
78	Primary Total	$53.99	$114.80		78
79					79
80	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)				80
81	Secondary	$1.56	$3.31		81
82	Primary	$1.55	$3.29		82
83	Total	$1.55	$3.30		83
84					84
85	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)				85
86	Secondary	$3.64	$7.74		86
87	Primary	$3.62	$7.70		87
88	Total	$3.64	$7.74		88
89					89
90	Total - Agricultural			$18,871	90
91					91
92	Lighting				92
93	Customer Marginal Cost ($/Lamp-Month)	$0.64	$1.36		93
94	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)	$0.59	$1.25		94
95	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)	$3.69	$7.85		95
96	Total - Lighting			$4,785	96
97					97

ATTACHMENT B.3 - REBUTTAL

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2019 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-002
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	$36.08	$76.71		102
103	>20 kW	$174.42	$370.84		103
104	Secondary Total	$118.43	$251.81		104
105					105
106	Primary				106
107	≤20 kW	$47.71	$101.44		107
108	>20 kW	$74.65	$158.72		108
109	Primary Total	$71.81	$152.68		109
110					110
111	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)				111
112	Secondary	$2.41	$5.12		112
113	Primary	$2.39	$5.09		113
114	Total	$2.41	$5.11		114
115					115
116	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)				116
117	Secondary	$4.65	$9.88		117
118	Primary	$4.62	$9.83		118
119	Total	$4.65	$9.88		119
120					120
121	Lighting				121
122	Customer Marginal Cost ($/Lamp-Month)	$0.64	$1.36		122
123	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)	$0.67	$1.42		123
124	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)	$4.65	$9.88		124
125	Total - Lighting				125
126					126
127	Total - School			$23,480	127
128					128
129	Total-System				129
130	Customer Marginal Cost ($/Customer-Month)			$568,338	130
131	Summer On-Peak Demand-Related Marginal Cost ($/On-Peak kW)			$126,662	131
132	Non-Coincident Demand-Related Marginal Cost ($/Non-Coincident kW)			$878,804	132
133	Total - System			$1,573,804	133

ATTACHMENT B.3 - REBUTTAL

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2019 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-002
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.
	GRC Phase 1 Distribution Revenue Requirement:	1,588,811			
	Non-Marginal Revenue Requirement	15,006			
	Marginal Distribution Revenue Requirement Allocation	1,573,804			
	Marginal Customer Distribution Revenue Requirement	267,305			
	Marginal Demand-Related Distribution Revenue Requirement	472,898			
	Total Marginal Distribution Revenue Requirement	740,203			
	EPMC Allocation Factor	212.62%			

Notes:

(1) **Distribution EPMC Rates and Revenues by Customer Class**: the distribution EPMC rates and revenues by customer class presented are from the rebuttal testimony workpapers of SDG&E 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 - REBUTTAL

SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
TEST YEAR ("TY") 2019 GENERAL RATE CASE ("GRC") PHASE 2, APPLICATION ("A.") 19-03-002
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		$69.35			2
3						3
4	Small Commercial					4
5		0 - 5 kW	$109.49	$183.60		5
6		>5 - 20 kW	$168.28	$183.60		6
7		>20 - 50 kW	$321.30	$183.60		7
8		>50 kW	$471.45	$217.45		8
9						9
10	Medium/Large Commercial & Industrial					10
11		≤500 kW	$1,254.14	$724.06	$2,755.69	11
12		500 - 12 MW	$2,689.58	$767.12	$3,612.67	12
13		> 12 MW		$714.24	$4,775.15	13
14						14
15	Agricultural					15
16		≤20 kW	$238.32	$295.63		16
17		>20 kW	$473.85	$317.17		17
18						18
19	Lighting ($/Lamp/Year)		$2.83			19
20						20
21	School					21
22		Non-Lighting ($/Customer/Year)				22
23		≤20 kW	$195.61	$295.63		23
24		>20 kW	$1,890.67	$664.76		24
25						25
26		Lighting ($/Lamp/Year)	$2.83			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.

ATTACHMENT D

PROPOSED REASSIGNMENT OF ELECTRIC DISTRIBUTION CAPITAL BUDGET ITEMS

ATTACHMENT D - REBUTTAL
SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
CAL PA PROPOSED MODIFICATIONS TO BUDGET CODE COST CLASSIFICATIONS

Budget Item	SDG&E Assignment	Cal Advocates Proposed Assignment	SDG&E's Position on Cal Advocates Budget Code Cost Classification Modifications
203	**Substation**	**Reliability-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2012 GRC should be assigned to reliability-substation, consistent with the assignment of these costs in the 2019 and 2016 GRCs.**
209	**Capacity**	**Capacity-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2012 GRC should be assigned to reliability-substation, consistent with the assignment of these costs in the 2019 and 2016 GRCs.**
214	**New Business Customer**	**Capacity**	**Disagree. Capacity costs associated with new business customers has already been reflected in the capacity costs. However, the assignment in the 2019 and 2016 GRCs need to be changed to new business customer to be consistent with the 2012 GRC.**
215	New Business Demand	Capacity	Disagree. New business demand costs do not reflect capacity costs. The capacity costs associated with new business customers has already been reflected in the capacity costs.
216	New Business Demand	Capacity	Disagree. New business demand costs do not reflect capacity costs. The capacity costs associated with new business customers has already been reflected in the capacity costs.
217	New Business Demand	Capacity	Disagree. New business demand costs do not reflect capacity costs. The capacity costs associated with new business customers has already been reflected in the capacity costs.
218	New Business Demand	Capacity	Disagree. New business demand costs do not reflect capacity costs. The capacity costs associated with new business customers has already been reflected in the capacity costs.
219	New Business Demand	Capacity	Disagree. New business demand costs do not reflect capacity costs. The capacity costs associated with new business customers has already been reflected in the capacity costs.
901	**Missing**	**Overhead Pools**	**Agree. These pool costs were mistakenly left out of the 2012 GRC costs and should be included for proration to capacity costs.**
904	**Missing**	**Overhead Pools-Substation**	**Agree. These pool costs were mistakenly left out of the 2012 GRC costs and should be included for proration to substation-capacity costs.**
905	**Missing**	**Overhead Pools**	**Agree. These pool costs were mistakenly left out of the 2012 GRC costs and should be included for proration to capacity costs.**
906	**Missing**	**Overhead Pools**	**Agree. These pool costs were mistakenly left out of the 2012 GRC costs and should be included for proration to capacity costs.**
1269	Reliability-Substation	Capacity-Substation	Disagree. These costs in the 2019 and 2016 GRCs are associated with making changes to the substation to meet reliability needs not to meet an increase in capacity of SDG&E customers and thus, these costs were correctly assigned to reliability-substation.
1295	Mandated	Capacity	Disagree. These costs in the 2016 and 2012 GRCs are associated with collecting data to support load research metering and load collection requirements and thus, these costs were correctly assigned to mandated.
2252	Substation	Capacity-Substation	No issue since substation and capacity-substation labeling in the 2012 GRC are the same.
3183	**Capacity-Transmission**	**Capacity**	**Agree. Although these costs are related to transmission, these costs in the 2012 GRC should be assigned to capacity as proposed by Cal Advocates.**
5153	**Capacity-Transmission**	**Capacity**	**Agree. Although these costs are related to transmission, these costs in the 2012 GRC should be assigned to capacity as proposed by Cal Advocates.**
6129	**Reliability-Substation**	**Capacity-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2019 and 2012 GRCs should be assigned to capacity-substation.**
6132	**Reliability-Substation**	**Capacity-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2016 GRC should be assigned to capacity-substation.**
6245	Reliability	Capacity	Disagree. These costs in the 2012 GRC are associated with making changes to the circuits to meet reliability needs not to meet an increase in capacity of SDG&E customers and thus, these costs were correctly assigned to reliability.
6250	**Reliability**	**Reliability-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2012 GRC should be assigned to reliability-substation.**
6251	**Reliability-Substation**	**Capacity-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2012 GRC should be assigned to capacity-substation.**

ATTACHMENT D - REBUTTAL
SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
CAL PA PROPOSED MODIFICATIONS TO BUDGET CODE COST CLASSIFICATIONS

Budget Item	SDG&E Assignment	Cal Advocates Proposed Assignment	SDG&E's Position on Cal Advocates Budget Code Cost Classification Modifications
6254	**Reliability**	**Reliability-Substation**	**Agree. SDG&E agrees with Cal Advocates that these 2012 GRC costs should be assigned to reliability-substation, consistent with the assignment of these costs in the 2019 and 2016 GRCs.**
6260	Reliability-Substation	Reliability-Substation	No issue since both SDG&E and Cal Advocates assigned these costs in the 2012 GRC to reliability-substation.
7139	**Reliability-Substation**	**Capacity-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2016 GRC should be assigned to capacity-substation.**
7144	**Reliability**	**Reliability-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2012 GRC should be assigned to reliability-substation, consistent with the assignment of these costs in the 2019 and 2016 GRCs.**
7245	**Reliability**	**Capacity**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2019 GRC should be assigned to capacity.**
7257	Substation	Capacity-Substation	No issue since substation and capacity-substation labeling in the 2012 GRC are the same.
8253	**Capacity**	**Capacity-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs should be assigned to capacity-substation, consistent with the assignment of these costs in the 2019 and 2016 GRCs.**
8254	Reliability-Substation	Reliability-Substation	No issue since both SDG&E and Cal Advocates assigned these costs in the 2012 GRC to reliability-substation.
8261	Reliability-Substation	Reliability-Substation	No issue since both SDG&E and Cal Advocates assigned these costs in the 2016 and 2012 GRCs to reliability-substation.
8262	Reliability-Substation	Reliability-Substation	No issue since both SDG&E and Cal Advocates assigned these costs in the 2012 GRC to reliability-substation.
9148	**Capacity-Transmission**	**Capacity**	**Agree. Although these costs are related to transmission, these costs in the 2012 GRC should be assigned to capacity as proposed by Cal Advocates.**
9149	**Capacity-Transmission**	**Capacity**	**Agree. Although these costs are related to transmission, these costs in the 2012 GRC should be assigned to capacity as proposed by Cal Advocates.**
9153	Reliability	Capacity	Disagree. These costs in the 2019 and 2016 GRCs reflect costs to maintain system reliability by maintaining the NERC reliability criteria and thus, these costs were correctly assigned to reliability.
9166	Reliability	Capacity	Disagree. These costs in the 2016 GRC reflect costs to meet CAISO requirements and thus, these costs were correctly assigned to reliability.
9271	**Capacity**	**Capacity-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in 2019 and 2012 should be assigned to capacity-substation.**
9276	**Capacity**	**Capacity-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2012 GRC should be assigned to capacity-substation, consistent with the assignment of these costs in the 2016 GRC.**
9281	Reliability-Substation	Reliability-Substation	No issue since both SDG&E and Cal Advocates assigned these costs in the 2012 GRC to reliability-substation.
9283	Reliability-Substation	Reliability-Substation	No issue since both SDG&E and Cal Advocates assigned these costs in the 2012 GRC to reliability-substation.
9295	**Capacity-Transmission**	**Capacity**	**Agree. Although these costs are related to transmission, these costs in the 2012 GRC should be assigned to capacity as proposed by Cal Advocates.**
10125	**Reliability-Substation**	**Capacity-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2012 GRC should be assigned to capacity-substation.**
10135	Reliability-Substation	Capacity-Substation	Disagree. These costs in the 2019 and 2016 GRCs are associated with making changes to the substation to meet reliability needs not to meet an increase in capacity of SDG&E customers and thus, these costs were correctly assigned to reliability-substation.
10253	Substation	Capacity-Substation	No issue since substation and capacity-substation labeling in the 2012 GRC are the same.
10259	Reliability-Substation	Reliability-Substation	No issue since both SDG&E and Cal Advocates assigned these 2012 GRC costs to reliability-substation.
11126	Reliability	Capacity	Disagree. These costs in the 2019 and 2016 GRCs reflect costs to maintain system reliability by maintaining the NERC reliability criteria and thus, these costs were correctly assigned to reliability.
11127	Reliability	Capacity	Disagree. These costs in the 2016 GRC reflect costs to maintain system reliability by maintaining the NERC reliability criteria and thus, these costs were correctly assigned to reliability.

ATTACHMENT D - REBUTTAL
SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
CAL PA PROPOSED MODIFICATIONS TO BUDGET CODE COST CLASSIFICATIONS

Budget Item	SDG&E Assignment	Cal Advocates Proposed Assignment	SDG&E's Position on Cal Advocates Budget Code Cost Classification Modifications
11246	Reliability	Capacity	Disagree. These costs in the 2019 GRC reflect costs to monitor the impact of EV charging on transformers so these costs are needed for reliability purposes and thus, these costs were correctly assigned to reliability.
11247	Reliability	Capacity	Disagree. These costs in the 2019 GRC reflect costs to mitigate operational problems from renewable energy sources by installing energy storage and thus, these costs were correctly assigned to reliability.
12125	Reliability-Substation	Capacity-Substation	Disagree. These costs in the 2016 GRC are associated with upgrading the substation to meet reliability needs not to meet increased capacity needs and thus, these costs were correctly assigned to reliability-substation.
12243	Reliability	Reliability-Substation	Disagree. These costs in the 2019 GRC reflect circuit reliability costs not substation reliability.
12246	Reliability	Reliability-Substation	Disagree. These costs in the 2019 GRC reflect circuit reliability costs not substation reliability.
12266	Reliability	Reliability-Substation	Disagree. These costs in the 2019 and 2016 GRCs reflect circuit reliability costs not substation reliability.
13130	**Reliability**	**Reliability-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2019 and 2016 GRC should be assigned to reliability-substation.**
13143	Reliability	Capacity	Disagree. These costs in the 2016 GRC reflect costs to meet CAISO requirements and thus, these costs were correctly assigned to reliability.
13242	**Reliability-Substation**	**Capacity-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2019 and 2016 GRCs should be assigned to capacity-substation.**
13243	**Reliability-Substation**	**Capacity-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2019 GRC should be assigned to capacity-substation.**
13244	**Reliability-Substation**	**Capacity-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2019 GRC should be assigned to capacity-substation.**
15246	**Safety and Risk Management**	**Reliability-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2019 GRC should be assigned to reliability-substation.**
15259	**Safety and Risk Management**	**Reliability-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2019 GRC should be assigned to reliability-substation.**
16260	Reliability-Substation	Capacity-Substation	Disagree. These costs in the 2019 GRC are associated with making changes to the substation to meet reliability needs not to meet an increase in capacity of SDG&E customers and thus, these costs were correctly assigned to reliability-substation.
17247	**Reliability**	**Reliability-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2019 GRC should be assigned to reliability-substation.**
17249	**Safety and Risk Management**	**Reliability**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2019 GRC should be assigned to reliability.**
94241	**Reliability**	**Reliability-Substation**	**Agree. SDG&E agrees with Cal Advocates that these costs in the 2016 and 2012 GRCs should be assigned to reliability-substation.**
94245	Reliability	Reliability-Substation	Disagree. These costs in the 2012 GRC are associated with making changes to the circuits to meet reliability needs and thus, these costs were correctly assigned to reliability.
99282	Reliability-Substation	Reliability-Substation	No issue since both SDG&E and Cal Advocates assigned these 2012 GRC costs to reliability-substation.
2008 GRC Phase 2 Distribution Capital Costs	Assigned As Presented in 2008 GRC Phase 2	Adjustments Compared to Assignments of Distribution Capital Costs in other GRCs	SDG&E Disagrees with Cal Advocates proposal to make adjustments to the distribution capital costs presented in the 2008 GRC Phase 2 proceeding either by indexing these costs to the costs presented in the other GRC Phase 2 proceedings, or other adjustments it deems necessary based on no evidence.

ATTACHMENT E

FORECASTED DISTRIBUTION CAPACITY COSTS COMPARED TO ACTUAL DISTRIBUTION CAPACITY COSTS

ATTACHMENT E - REBUTTAL
SAN DIEGO GAS & ELECTRIC COMPANY ("SDG&E")
FORECASTED AND ACTUAL DISTRIBUTION CAPACITY COSTS AND PERCENTAGES

	Updated Forecasted Costs ($000)			Actual Costs ($000)		
	2017	2018	2019	2017	2018	2019
Feeder & Local Distribution ("FLD")						
FLD Capacity-Related Costs	$13,154	$8,632	$11,692	$12,909	$6,551	$11,844
Total FLD Costs	$313,166	$441,230	$519,056	$314,240	$304,835	$464,364
FLD Capacity-Related Costs as % of Total FLD Costs	4.2%	2.0%	2.3%	4.1%	2.1%	2.6%
Substation						
Substation Capacity-Related Costs	$29,806	$31,110	$37,902	$37,913	$34,035	$19,440
Total Substation Costs	$54,669	$73,187	$105,194	$75,847	$60,016	$30,425
Substation Capacity-Related Costs as % of Total Substation Costs	54.5%	42.5%	36.0%	50.0%	56.7%	63.9%

Sources:
(1) Updated Forecasted Costs identified in the "Dist Capital Forecast Data" tab of the "Ch_5_WP#4_Marg Demand Costs_Rebuttal" Chapter 5 workpaper file.
(2) Actual Costs identified in the "Dist Capital Actual Data" tab of the "Ch_5_WP#4_Marg Demand Costs_Rebuttal" Chapter 5 workpaper file.