

Exhibit No: \_\_\_\_\_  
Application: A.25-09-014  
Witness: F. Seres and M. Schmidt Pines  
Chapter: 19

**PREPARED REBUTTAL TESTIMONY OF  
FRANK SERES AND MARJORIE SCHMIDT-PINES  
ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY  
AND SAN DIEGO GAS & ELECTRIC COMPANY  
(COST ALLOCATION, EMBEDDED COSTS, AND LONG RUN MARGINAL COSTS)**

June 15, 2026

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**CHAPTER 8 & CHAPTER 9**  
**PREPARED REBUTTAL TESTIMONY OF FRANK SERES**  
**AND MARJORIE SCHMIDT-PINES**  
**(EMBEDDED COSTS AND LONG-RUN MARGINAL COSTS)**

**I. PURPOSE**

This joint rebuttal testimony addresses the direct testimonies of Public Advocates Office (Cal Advocates), The Utility Reform Network (TURN), and Indicated Shippers (IS) which were served on May 15, 2026. These intervenors addressed Applicants' proposals contained in Chapter 8 (Seres and Schmidt-Pines) and Chapter 9 (Schmidt-Pines) related to the cost allocation for SoCalGas's and SDG&E's (II) Cost Allocation methodology, (III) Asset Retirement Obligation (ARO), (IV) Backbone to Local Transmission reallocation treatment, (V) Marginal Demand Measures, and (VI) Administrative & General (A&G) and Plant functionalization.<sup>1</sup>

**II. COST ALLOCATION METHODOLOGY**

**A. The Commission Should Reject Cal Advocates' Proposal to Retain Long Run Marginal Cost (LRMC) for Distribution and Customer Service**

As a threshold matter, Applicants propose the LRMC study be discontinued in future cost allocation proceedings (CAPs).

Cal Advocates proposes to retain the LRMC as a binding benchmark for the customer-related and distribution functions, consistent with Decision (D.) 24-07-009 and to reject SoCalGas's and SDG&E's proposal to adopt embedded cost as the universal methodology for future cost allocation proceedings (CAPs).<sup>2</sup> In Applicants' direct testimony, Chapter 9, page MSP-4, Applicants explained that the reason is to use the embedded cost approach for ratemaking.<sup>3</sup>

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<sup>1</sup> Given the volume of the various arguments, positions, and proposals raised by intervenors, Applicants have prioritized which issues to address in rebuttal testimony. Silence on any issue should not be construed as agreement with, or non-opposition to, that issue, as Applicants reserve the right to address additional issues not specifically mentioned in this rebuttal testimony at a later opportunity, such as evidentiary hearings and briefs.

<sup>2</sup> Direct Testimony of Maricela Sierra on behalf of Public Advocates Office (Ex. CA-05) at 2, 6-7.

<sup>3</sup> Direct Testimony of Frank Seres and Marjorie Schmidt-Pines (SCG-SDGE, Chapter 8) at FS-MSP-4-5.

1 Here, Applicants’ proposal should be adopted notwithstanding Cal Advocates’ proposal.  
2 As background, Applicants’ reliance on an embedded cost approach, and their proposal not to  
3 retain LRMC cost studies in future CAPs, reflect current Commission policy and market  
4 conditions. Specifically, Commission policy is advancing decarbonization, and new residential  
5 construction no longer receives allowances for natural gas extensions. As a result, the residential  
6 capital marginal cost reflected in the LRMC studies is zero.<sup>4</sup> SoCalGas and SDG&E have  
7 existing capital-related revenue requirements associated with service to their residential customer  
8 classes<sup>5</sup>. These costs are reflected in the utilities’ embedded cost study and must be allocated  
9 appropriately in the cost allocation analysis<sup>6</sup>. The embedded cost study relies on historical  
10 investment and expense data<sup>7</sup>, capturing previously authorized capital expenditures and  
11 associated carrying costs. Accordingly, the study provides a backward-looking representation of  
12 cost causation and recovery<sup>8</sup>, forming the basis for allocating embedded costs to residential  
13 existing customers in a manner consistent with regulatory principles of cost responsibility<sup>9</sup>.

14 Furthermore, TURN, Clean Energy, and Indicated Shippers in their respective opening  
15 testimonies appear to be aligned with Applicants for the embedded cost approach.<sup>10</sup>

16 **B. The Commission Should Reject Cal Advocates’ Proposal to Recalibrate the**  
17 **Transition Adjustment**

18 The Commission should reject Cal Advocates’ proposal to recalibrate the transition  
19 adjustment using affordability-metrics.<sup>11</sup> (In Chapter 8, pages FS-MSP-36 and FS-MSP-37, the  
20 \$150 million proposed transition adjustment, reducing Residential allocated Base Margin and  
21 increasing Core C&I allocated Base Margin is discussed.) The proposed amount was calculated

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<sup>4</sup> *Id.*

<sup>5</sup> FS-MSP, Ch.8 Tables FS-MSP-26, FS-MSP-28

<sup>6</sup> *Id.* at FS-MSP-2, lines 22-24

<sup>7</sup> *Id.* at FS-MSP-5, lines 11-16

<sup>8</sup> *Id.* at FS-MSP, lines 2-3

<sup>9</sup> *Id.* at FS-MSP-4, lines 12-16; FS-MSP-31, lines 12-13

<sup>10</sup> Direct Testimony of Michael P. Florio on behalf The Utility Reform Network (Ex. TURN-01) at 5; Direct Testimony of Allison F. Smith on behalf of Clean Energy (Ex. CE-01) at 3; Direct Testimony of Brian C. Collins on behalf of Indicated Shippers (Ex. IS-01) at 24.

<sup>11</sup> Ex. CA-05 (Sierra) at 9-10.

1 so that the percentage rate changes for Residential and Core C&I are close. This promotes  
2 stable rates while we transition to fully cost based rates. Cal-Advocates recommend using the  
3 Affordability-metrics-based recalibration. However, this tool does not determine rates  
4 adjustments. TURN and Indicated Shippers along with SoCalGas and SDG&E support the  
5 proposed transition adjustment.<sup>12</sup>

6 **C. The Commission Should Reject TURN’s Non-Uniform, Function-Specific**  
7 **Scaling Proposal**

8 The Commission should reject TURN’s non-uniform, function-specific scaling  
9 proposal.<sup>13</sup> SoCalGas and SDG&E propose to use the scalar to adjust the proposed cost  
10 revenues to the base margin, excluding costs directly allocated to the Uncollectible, and NGV  
11 Public Access functions. As shown in Chapter 8, SoCalGas Table FS-MSP-26 and SDG&E  
12 Table FS-MSP-28, the scalar is applied at the same rate for the functions: Customer Cost,  
13 Medium Pressure Distribution, High Pressure Distribution, Transmission, and Storage. TURN  
14 states, “This is a vast improvement over the companies’ practice established in multiple previous  
15 CAPs of fixing the embedded costs of transmission and storage at the prior recorded historical  
16 level and then scaling on distribution costs (determined by LRMC) to match the revenue  
17 requirement.”<sup>14</sup> TURN then explains that the revenue requirements for each function are  
18 increasing at different rates.<sup>15</sup> TURN’s proposal substitutes hindsight for record evidence. At  
19 filing, Applicants had a complete recorded 2024 FERC basis; whereas, TURN did not have 2027  
20 recorded costs or adopted 2027 function-specific revenue requirements. A non-uniform scalar  
21 would require Applicants to predict which functions will increase faster during the 2027-2029  
22 CAP period, thereby inviting arbitrary inter-functional cost shifting. Equal-percentage scaling is  
23 not a claim that every function actually increases at the same rate. It is a neutral reconciliation  
24 method that preserves the 2024 recorded embedded functionalization, recovers authorized Base  
25 Margin, and avoids using retrospective trend as prospective revenue requirements. TURN may  
26 test actual 2027 functional changes after the 2027 recorded FERC data exists (approx. 2028

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<sup>12</sup> Ex. TURN-01 (Florio) at 4; Ex. IS-01 (Collins) at 25.

<sup>13</sup> Ex. TURN-01 (Florio) at 7-8.

<sup>14</sup> *Id.*

<sup>15</sup> Ex. TURN-01 (Florio) at 8.

1 April), but it has not provided the prospective data needed to replace uniform scaling in this  
2 record.

3 Absent known 2027 recorded FERC costs by function, uniform scaling is the only record-  
4 supported, administratively neutral method that applies the same adjustment to all functions and  
5 avoids unsupported redistribution among customer classes.

6 **D. Practical and Structural Limitations for TURN’s Proposed FERC Account**  
7 **Mapping Recruitment**

8 TURN recommends SoCalGas and SDG&E, in their 2026 GRC phase one filing for Test  
9 Year 2028, to provide a complete mapping of GRC dollars to FERC accounts in a separate  
10 exhibit, which could then be utilized for cost allocation.<sup>16</sup> SoCalGas and SDG&E use FERC  
11 accounts to properly reassign costs to capital, and segment costs on the SDGE side of the  
12 business. This is only related to O&M.

13 The Results of Operation (RO) model that SoCalGas and SDG&E use to turn the  
14 proposed forecasted direct O&M and capital costs into a revenue requirement does not have the  
15 functionality or detail to map those revenue requirements to FERC accounts. SoCalGas and  
16 SDG&E propose a total company test-year revenue requirement and does not functionalize it  
17 into separate groupings such as transmission and distribution. While the RO model does have  
18 FERC account data, the main purpose is to segment costs and reassign O&M costs to capital.  
19 SCG and SDG&E forecast their costs using non-shared O&M workgroups (bundled cost  
20 centers), shared-service O&M cost centers, and capital budget codes. These three types of  
21 forecasts are not forecasted using FERC account level detail.

22 **E. The Commission Should Reject Cal Advocates’ Proposal to Separate**  
23 **Disclosure of PSEP and TIMP**

24 The Commission should reject Cal Advocates proposal requiring explicit ring-fencing  
25 and separate disclosure of Pipeline Safety Enhancement Program (PSEP) and Transmission  
26 Integrity Management Program (TIMP) and preserve functional allocation requirements of D.14-  
27 06-007 and D.16-12-063.<sup>17</sup> In this regard, Applicants’ proposal (as set forth in in Chapter 8,

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<sup>16</sup> Ex. TURN-01 (Florio) at 12-15.

<sup>17</sup> Ex. CA-05 (Sierra) at 4, 9.

1 pages FS\_MSP-27) regarding the costs related to Base Margin PSEP (including GRC and  
2 GRCMA PSEP) are incorporated into the Embedded Cost Study. The GRC PSEP and TIMP  
3 costs are functionalized. The PSEP and TIMP balancing accounts outside of Base Margin are  
4 allocated separately. SoCalGas and SDG&E propose to include Base Margin PSEP and TIMP in  
5 the embedded cost study and not to separately allocate costs.

6 Applicants' proposal in Chapter 8 already distinguishes between PSEP costs that are not  
7 in Base Margin and PSEP costs that are in Base Margin. Costs not in Base Margin are excluded  
8 from the embedded cost study and functionally allocated to High Pressure Distribution and  
9 Transmission consistent with D.14-06-007 and D.16-12-063. By contrast, PSEP costs included in  
10 Base Margin are part of the embedded cost studies for Transmission and High Pressure  
11 Distribution.<sup>18</sup> Applicants' Chapter 8 testimony also states that the SoCalGas \$198 million and  
12 SDG&E \$15 million differences are due to PSEP costs included in Base Margin, and that those  
13 costs are included in the studies and are not allocated separately as they are in current rates.<sup>19</sup>

14 Cal Advocates' proposal should be rejected because it conflicts with two different  
15 categories of PSEP costs. Where PSEP costs remain outside Base Margin, Applicants' proposal  
16 (Chapter 8) already preserves separate treatment and applies the applicable functional allocation.  
17 But once PSEP costs have been authorized in the GRC and included in Base Margin, they  
18 become part of the revenue requirement to be allocated in this CAP like other embedded costs.  
19 Segregating the GRC PSEP and TIMP is a very cumbersome and burdensome process, and the  
20 accounting systems are not set up to extract the data separately. The impact on rates is very  
21 minimal. Cal Advocates has not identified a Commission directive requiring those GRC-  
22 authorized Base Margin costs to be carved out a second time or ring-fenced again in the  
23 embedded cost study.

24 That distinction matters. CAP is not the forum to relitigate whether PSEP costs should be  
25 in Base Margin after the GRC has already placed them there. The CAP function is to allocate  
26 authorized Base Margin among customer classes using the adopted cost allocation methodology.  
27 Requiring a new PSEP/TIMP ring-fence after those costs have entered Base Margin would create

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<sup>18</sup> SCG-SDGE, Chapter 8 (Seres and Schmidt-Pines) at FS-MSP-3, fn.5.

<sup>19</sup> SCG-SDGE, Chapter 8 (Seres and Schmidt-Pines) at FS-MSP-36.

1 a hybrid allocation: one set of embedded costs would be treated normally, while another  
2 Commission-authorized subset would be re-isolated without a separate directive to do so.

3 Cal Advocates also cites D.14-06-007 and D.16-12-063 generally, but the provided  
4 testimony notably does not identify a page, ordering paragraph, or finding requiring PSEP/TIMP  
5 costs already included in Base Margin to be separately ring-fenced in this CAP.

6 In sum, the Commission should reject Cal Advocates' ring-fencing proposal. Applicants'  
7 treatment is reasonable: PSEP costs outside Base Margin remain separately treated; PSEP costs  
8 inside Base Margin are properly included in the embedded Transmission and High Pressure  
9 Distribution studies.

10 **F. The Commission Should Reject TURN's Storage Percent Allocation Change.**  
11 **It Swaps Applicants' Operations-Based Study for Unsupported Judgment**  
12 **that also Benefits Core Customers**

13 Applicants' Chapter 8 testimony complied with D.24-07-009 by including a detailed  
14 capital/O&M storage allocation percentage study to allocate storage costs among injection,  
15 withdrawal, and inventory.<sup>20</sup> Applicants relied on storage operations experts to evaluate activities  
16 and functionalize storage costs based on cost-causation concepts.<sup>21</sup> Applicants' Chapter 8  
17 testimony allocates total storage costs 29.8% to injection, 32.9% to withdrawal, and 37.3% to  
18 inventory.<sup>22</sup>

19 TURN proposes to change the allocation of FERC Accounts 352, 353, 816, 817, 832, and  
20 833, covering storage wells, lines, well expenses, line expenses, and related maintenance  
21 accounts from Applicants' 50% inventory, 39% withdrawal, 11% injection approach to TURN's  
22 10% inventory, 70 % withdrawal, 20% injection approach. TURN's approach would reduce total  
23 inventory functionalization from 37.3% to 17.7%.<sup>23</sup> TURN's proposal should be rejected.  
24 SoCalGas uses all of its wells and associated compression systems not just to maintain inventory,  
25 but to ensure sufficient withdrawal capacity to reliably meet customer demand. While fewer  
26 wells could theoretically maintain inventory, they would not provide the rapid injection capacity

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<sup>20</sup> SCG-SDGE, Chapter 8 (Seres and Schmidt-Pines) at FS-MSP Appendix E-2.

<sup>21</sup> *Id.*

<sup>22</sup> *Id.* at Appendix E-1.

<sup>23</sup> Ex. TURN-01 (Florio) at 59-60.

1 and subsequent deliverability required during periods of peak or rapidly changing demand  
2 conditions.

3           TURN does not identify an operational study showing that inventory support is only 10%  
4 of wells and lines costs. Instead, TURN substitutes judgment for the storage-operations analysis  
5 Applicants prepared. TURN’s position is also directionally consistent with its advocacy for core  
6 customers: inventory is the storage sub-function most heavily assigned to Core Reservation, so  
7 sharply reducing inventory necessarily reduces core responsibility relative to Applicants’ study.  
8 That advocacy position, however, is not a cost-causation showing. Applicants should state that  
9 the storage study was also presented in workshops in compliance with D.24-07-009 where initial  
10 results were reviewed using a fully embedded cost allocation approach

11           The Commission should adopt Chapter 8’s storage functionalization because it is based  
12 on recorded 2024 costs, account-specific operational review, and a balanced recognition that  
13 wells and lines support not only injection and withdrawal capacity, but also the ability to hold  
14 and utilize inventory.

### 15 **III. ASSET RETIREMENT OBLIGATION (ARO)**

#### 16 **A. The Commission Should Reject TURN’s Proposal to Exclude Asset** 17 **Retirement Obligations (AROs) from Embedded Cost Study**

18           The Commission should reject TURN’s proposal to exclude AROs. Procedurally,  
19 TURN’s proposal departs from the Commission’s prior determination to include ARO in the  
20 embedded cost study, D.20-02-045<sup>24</sup> and a misreading of D.24-07-009: a workshop sensitivity is  
21 not a filing requirement. Substantively, TURN treats legally required asset-retirement costs as if  
22 they were detachable from the assets that cause them. They are not. AROs are tied to the  
23 retirement or decommissioning of plants used to provide utility service. In A.22-09-015<sup>25</sup>  
24 Chapter 17, Applicants explained that the corresponding Asset Retirement Cost is recorded as an  
25 asset and depreciated monthly. Removing AROs would override the recorded FERC plant data  
26 that Applicants’ Chapter 8 uses to functionalize embedded costs, break consistency with the  
27 Commission-approved approach, and selectively reduce distribution-related plant values because

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<sup>24</sup> D.20-02-045 at 102-103, It is ordered 4.d. “include asset retirement obligations in the embedded cost study.”

<sup>25</sup> A.22-09-015, SCG-SDGE, Chapter 17 (Seres) at 10, available at: [515355346.pdf](#).

1 most AROs are associated with distribution. That is not cost causation; it is outcome-driven re-  
2 functionalization.

3 In sum, Applicants' proposal complied with D.24-07-009 by presenting the no-ARO  
4 workshop scenario<sup>26</sup>; the filed embedded cost study in this case properly includes AROs in  
5 accordance with D.20-02-045,<sup>27</sup> Chapter 8's 2024 FERC Form 2 methodology, and the cost-  
6 causation principle. TURN's no-ARO calculation should be treated only as an unsupported  
7 alternative sensitivity.

8 **B. The Commission Should Reject Indicated Shippers' Argument that AROs**  
9 **are Future-Period Decommissioning Estimates**

10 Indicated Shippers asks the Commission to remove AROs from the embedded cost base,  
11 arguing that AROs are future-period decommissioning estimates, not current plant, and that their  
12 inclusion is inconsistent with cost causation.<sup>28</sup>

13 The Commission already addressed this issue in D.20-02-045<sup>29</sup>, finding that AROs are  
14 not merely a financial reporting requirement, but are asset-related incremental costs that should  
15 be included in the embedded cost study, and denying the request to omit AROs<sup>30</sup>. D.20-02-045  
16 also directed future TCAP/CAP applications to include AROs in the embedded cost study.<sup>31</sup>

17 Indicated Shippers improperly applies a GRC rate-base recovery theory to a CAP  
18 embedded cost allocation study.<sup>32</sup> Applicants are not proposing a separate ARO surcharge or  
19 standalone ARO recovery. Rather, Applicants' Chapter 8 uses recorded FERC Form 2 plant and  
20 cost data to functionalize embedded costs. Excluding AROs would selectively remove a

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<sup>26</sup> D.24-07-009, Attachment A at 3.

<sup>27</sup> D.20-02-045 at 102-103, It is ordered 4.d. "include asset retirement obligations in the embedded cost study."

<sup>28</sup> Ex. IS-01 (Collins) at 25.

<sup>29</sup> D.20-02-045 at 102-103, It is ordered 4.d. "include asset retirement obligations in the embedded cost study."

<sup>30</sup> D.20-02-045 at 33.

<sup>31</sup> *Id* at 34.

<sup>32</sup> Ex. IS-01 (Collins) at 25-26, 30.

1 recorded, asset-related component from the FERC-based study and make the study less  
2 consistent with the Commission-approved embedded-cost framework

3 Indicated Shippers' testimony acknowledges that ARO accounting produces both a  
4 liability and a capitalized Asset Retirement Cost (ARC), and that the ARC is added to the related  
5 plant account and depreciated over the asset's life.<sup>33</sup> That supports Applicants' position that  
6 ARO/ARC treatment is tied to utility assets and embedded plant accounting; it does not justify  
7 setting AROs to zero for class allocation.

8 The Commission should reject Indicated Shippers' ARO exclusion. Applicants' Chapter 8  
9 embedded cost study properly includes AROs in accordance with D.20-02-045, uses recorded  
10 2024 FERC data, and preserves consistency in the embedded cost study. At most, an ARO-  
11 excluded run should be treated as an informational sensitivity, not as the adopted cost allocation.

12 **IV. BACKBONE TRANSMISSION (BBT) TO LOCAL TRANSMISSION (LT)**  
13 **REALLOCATION TREATMENT**

14 **A. The Commission Should Reject TURN's Opposition to Applicants' Peak-Day**  
15 **Methodology because Annual Data Corroborates nearly the same**  
16 **Reallocation**

17 TURN argues that Applicants could make the issue "go away" by adding "*or to a large*  
18 *end-use customer*" to the BBT definition; relies on PG&E's different backbone-only rate design;  
19 and contends that Applicants should have used the backbone (BB) complement, approximately  
20  $31\% \times 30\% = 9.3\%$ , rather than the LT percentage used in Chapter 8.<sup>34</sup>

21 TURN's position is not a cost-causation rebuttal; it is a relabeling exercise. Changing one  
22 phrase in a classification would not change the actual function performed by BBT assets when  
23 those assets directly serve EG load. Chapter 8 does not reclassify entire BBT lines as LT. It  
24 assigns a reasonable portion of BBT costs to LT because those assets provide an LT delivery  
25 function for certain EG customers.

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<sup>33</sup> Ex. IS-01 (Collins) at 28.

<sup>34</sup> Ex. TURN-01 (Florio) at 32-33, 35.

1 TURN's reliance on PG&E is also misplaced<sup>35</sup>. PG&E's design does not determine the  
2 functional use of Applicants' integrated system. The relevant question is whether Applicants'  
3 BBT assets perform an LT function; Chapter 8 Section VIII shows they do.

4 At the time Applicants served the initial response to TURN DR 2-12 (see below), the  
5 requested annualized analysis had not been prepared.

**Question 2-12.**

In Chapter 8, at page FS-MSP-25, the Utilities state that: "on a summer peak day, about 69% of total power-plant gas usage is served from LT pipelines on the SoCalGas transmission system." What percentage of total power plant gas usage was served from LT pipelines on an *annual* basis in each of the years 2022, 2023 and 2024?

**Response**

Applicants object on the grounds the request seeks an analysis not prepared by the Applicants. This request is seeking a new annualized analysis that was not prepared, relied upon, or required for the Chapter 8 backbone-to-local reallocation methodology.

6  
7 TURN requested additional analysis "*What percent of total power plant gas usage was*  
8 *served from LT pipelines on an annual basis in each of the years 2022, 2023, and 2024?*" and it  
9 required additional data compilation because it was not prepared, relied upon, or required in  
10 Chapter 8. Applicants have completed that analysis, and it confirms the reasonableness of  
11 Chapter 8 results.

12 The annualized EG throughput analysis TURN requested corroborates Applicants' filed  
13 result. LT-served EG usage was 62% in 2022, 68% in 2023, and 65% in 2024, producing an  
14 average annual LT share of [62%, 68%, 65%]=65%.

15 Applying that annual LT share to Chapter 8's EG system factor produces  $65\% \times 29.5\% =$   
16  $19.2\%$ , which very closely supports Chapter 8's filed 20% reallocation. Applicants' Chapter 8's  
17 filed calculation,  $69\% \times 29.5\% = 20\%$ , reallocates \$116.447 million from BBT to LT.<sup>36</sup>

18 The Commission should reject TURN's BB-complement calculation and adopt  
19 Applicants' 20% BBT-to-LT functional reallocation. Both the filed summer-peak analysis and

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<sup>35</sup> Ex. TURN-01 (Florio) at 33.

<sup>36</sup> SCG-SDGE, Chapter 8 (Seres and Schmitd-Pines) at FS-MSP-25-26; Tables FS-MSP-22A and FS-MSP-22B.

1 the annual EG throughput analysis “*What percent of total power plant gas usage was served*  
2 *from LT pipelines on an annual basis in each of the years 2022, 2023, and 2024*” support  
3 Applicants’ use of the LT percentage and demonstrate that the 20% reallocation is reasonable  
4 and supported.

5 **B. The Commission Should Reject Indicated Shippers’ Proposed \$91 Million**  
6 **Alternative Reallocation because it Does Not Disprove the Underlying Cost-**  
7 **Causation Basis for the Reallocation of BBT to LT**

8 Indicated Shippers characterizes the proposal as a “dual-use artifice,” and argues that  
9 Applicants’ calculation improperly combines summer peak-day data with annual EG demand,  
10 and recommends reducing the BBT-to-LT reallocation from \$116.4 million to approximately \$91  
11 million if any reallocation is adopted.<sup>37</sup>

12 Indicated Shippers’ proposed \$91 million alternative<sup>38</sup> does not disprove the underlying  
13 cost-causation basis for the reallocation. At most, it disputes the measurement. More importantly,  
14 its insistence on using peak-day demand for both steps would convert a functional embedded-  
15 cost allocation into a narrower peak-day-only exercise. Applicants’ Chapter 8 testimony is not  
16 assigning costs solely to serve one peak-day event; it is assigning annual embedded BBT costs  
17 based on the actual functions those assets perform.

18 The updated annual analysis for TURN DR 2-12 further confirms Applicants’ filed result.  
19 See section IV (a), above.

20 **C. The Commission Should Reject Cal Advocates’ Proposed Residential Carve-**  
21 **Out and Adopt Applicants BBT to LT Reallocation because it is a System**  
22 **Specific Functionalization supported by both the Filed Summer Peak**  
23 **Analysis and the Updated Annual EG Analysis**

24 Cal Advocates proposes that if BBT to LT relocation is not rejected, it should be  
25 conditioned on excluding residential customers from any incremental LT uplift and recalculating  
26 the reallocation percentage using a year-round or Cold Year Peak Month basis rather than a  
27 single summer EG peak day basis<sup>39</sup>. Cal Advocates’ criticism

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<sup>37</sup> Ex. IS-01 (Collins) at 31-33.

<sup>38</sup> Ex. IS-01 (Collins) at 33.

<sup>39</sup> Ex. CA-05 (Sierra) at 7-8.

1 conflates functionalization with class allocation. As Applicants explain in Chapter 8, Section  
2 VIII.A. (Backbone and Local Transmission Costs), the first step is to determine what function  
3 the transmission assets perform. Only after functionalization is complete are the resulting costs  
4 allocated to the customer classes. Applicants further explained that BBT and LT are classified  
5 by function, not by diameter, pressure, length, or number of customers served. BBT delivers  
6 supply to LT or storage facilities; LT delivers gas from BBT or storage to end-use customers.<sup>40</sup>  
7 Applicants also show that the actual system is hybrid in nature: certain end-use customers are  
8 served directly from BBT assets, meaning those assets perform both a primary BBT function and  
9 an LT delivery function.<sup>41</sup>

10 Cal Advocates' proposed residential carve-out is not cost-based.<sup>42</sup> If a portion of BBT  
11 assets performs an LT function, then those costs properly become part of the LT cost pool.  
12 Excluding residential customers from only the incremental LT portion would create a class-  
13 specific exemption from the LT allocator, not a cost-causation result. This analysis does not  
14 support eliminating the reallocation or exempting residential customers.

15 The updated annual analysis in Section IV(a), prepared in response to TURN DR 2-12,  
16 further confirms Applicants' result and refutes Cal Advocates' claim.

## 17 **V. MARGINAL DEMAND MEASURES**

### 18 **A. Commission Should Reject Indicated Shippers' Demand Measures Proposal**

19 The Commission should reject Indicated Shippers' recommendation to allocate local  
20 transmission and high pressure distribution by peak day instead of peak month throughput.<sup>43</sup>  
21 SoCalGas does not agree with Indicated Shippers' recommendation because it is not consistent  
22 with the Commission-adopted methodology to allocate these functional costs across customer  
23 classes. The Commission's Long Run Marginal Cost decision (D.92-12-058), which was a  
24 litigated outcome, clearly stated that SoCalGas's high pressure distribution and local  
25 transmission costs are to be allocated using Cold Year Peak Month gas demand as the decision

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<sup>40</sup> SCG-SDGE, Chapter 8 (Seres and Schmidt-Pines) at FS-MSP-21.

<sup>41</sup> SCG-SDGE, Chapter 8 (Seres and Schmidt-Pines) at FS-MSP-22, FS-MSP-24.

<sup>42</sup> Ex. CA-05 (Sierra) at 7-8.

<sup>43</sup> Ex. IS-01 (Collins) at 38 -44.

1 found that Cold Year Peak Month gas demand is the appropriate cost driver or marginal demand  
2 measure for these two functions.<sup>44</sup>

3 The Commission should also reject the Indicated Shippers proposal of allocating load  
4 balancing storage by peak day instead of average year throughput. In the 2016 Tri-Annual Cost  
5 Allocation Proceeding (TCAP) Phase 1 decision (D.16-06-039), the Commission, through its  
6 adoption of a settlement agreement, authorized results based on the use of Average Year  
7 Throughput for allocating Load Balancing costs, which continued the longstanding practice of  
8 allocating these costs in this manner. Indicated Shippers' proposed marginal demand measure of  
9 Peak Day gas demand for high pressure distribution, local transmission and storage load  
10 balancing allocation will also lead to significant cost shifts from noncore customers to core  
11 customers. Therefore, the Commission should reject these recommendations.

#### 12 **B. The Commission Should Reject TURN's Demand Measures Proposal**

13 The Commission should reject TURN proposal to allocate at least 80% of the SoCalGas  
14 and SDG&E distribution costs by annual throughput at the appropriate distribution level.<sup>45</sup>  
15 TURN indicates that PG&E has properly identified a "safety and reliability" category of costs  
16 that make up a large portion of the distribution revenue requirement, and that these costs bear no  
17 real relationship to peak day or peak month demand but rather are driven by regulatory  
18 compliance requirements and the imperative of providing safe and reliable utility service.<sup>46</sup> The  
19 testimony states that safety and reliable utility service are largely fixed in nature, given that they  
20 must be incurred independent of the level of demand on the system, as long as that system  
21 exists.<sup>47</sup> Yet, TURN contradicts this statement by proposing that 80% of SoCalGas/SDG&E  
22 distribution costs be allocated by annual throughput.<sup>48</sup> which is variable. SoCalGas does not  
23 agree with TURN's recommendation because it is not consistent with the Commission-adopted  
24 methodology to allocate these functional costs across customer classes. Also, as discussed  
25 above, if the costs are fixed allocating by volumes is contradictory. Eighty percent of the

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<sup>44</sup> D.92-12-058 at 66.

<sup>45</sup> Ex. TURN-01 (Florio) at 48-56.

<sup>46</sup> Ex. TURN-01 (Florio) at 79.

<sup>47</sup> Ex. TURN-01 (Florio) at 49.

<sup>48</sup> Ex. TURN-01 (Florio) at 54.

1 proposed demand allocated by annual throughput that TURN chooses is arbitrary and with no  
2 reasoning. The Commission’s Long Run Marginal Cost decision (D.92-12-058), which was a  
3 litigated outcome, clearly stated that SoCalGas’s high pressure distribution costs are to be  
4 allocated using Cold Year Peak Month gas demand as the decision found that Cold Year Peak  
5 Month gas demand is the appropriate cost driver or marginal demand measure. SoCalGas’s  
6 medium pressure distribution costs are to be allocated using Peak Day gas.<sup>49</sup> SoCalGas supports  
7 the recommendation in their next CAP to clearly delineate the portions of their distribution costs  
8 that are driven by peak demand versus the need for safety and reliability expenditures to  
9 maintain annual demand.

10 **C. The Commission Should Reject TURN’s Proposal to Allocate Distribution**  
11 **Rate Base and Depreciation Expense into HP Distribution, MP Distribution**  
12 **and Customer-Related Portions**

13 The Commission should reject TURN’s proposal of sub-functionalizing the distribution  
14 rate base and depreciation expense into High Pressure Distribution, Medium Pressure  
15 Distribution and Customer-related portions using the FERC plant accounts that make up that  
16 category of costs, as proposed in Section IV.B.<sup>50</sup> For reference, in Applicants’ Chapter 8  
17 testimony, SoCalGas propose allocating the Distribution and Customer Service by 2024 A&G  
18 expenditures, and SDG&E proposes to allocate based on Salaries and Wages and 2024 capital  
19 investment. These methods are also used in allocating A&G and General Plant. These are shown  
20 in the SoCalGas workpapers, SCG Embedded Cost Model\_Public\_DRAFT.xlsx, tab: Cost  
21 Allocation Dist A&G and in the SDG&E Embedded Cost Model\_Public\_DRAFT.xlsx  
22 workpapers, tab: Cost Allocation.) TURN agrees with Applicants’ investment allocation  
23 between High Pressure Distribution and Medium Pressure Distribution.<sup>51</sup>

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<sup>49</sup> D.92-12-058 at 66.

<sup>50</sup> Ex. TURN-01 (Florio) at 22-28.

<sup>51</sup> Ex. TURN-01 (Florio) at 34-35.

1 **VI. ADMINISTRATIVE & GENERAL (A&G), PLANT FUNCTIONALIZATION**

2 **A. The Commission Should Reject TURN's 80/20 Proposal to Allocate**  
3 **Administrative & General (A&G) and General Plant because it Substitutes**  
4 **an Unsupported Compromise for the Recorded Cost-Causation Proxy used**  
5 **in Chapter 8**

6 TURN's proposal states, "For purposes of this case, until more and better data is  
7 available, allocate only 80% of A&G costs by the labor factor and the remainder by a plant-in-  
8 service factor. Find that the General and Common Plant allocation can remain unchanged for  
9 now but must be fully justified in the next case."<sup>52</sup> TURN provides no empirical basis showing  
10 that exactly 20% of A&G costs are caused by plant-in-service. Indeed, TURN's own testimony  
11 acknowledges that the record is not sufficiently developed to determine the true nature of A&G  
12 expenses.<sup>53</sup> That admission does not support changing the filed cost study in this case; at most, it  
13 supports prospective data development.

14 TURN's capitalized-labor criticism is also incomplete. TURN states that FERC Form 2  
15 does not break down capitalized labor by function and therefore it is not possible, with the  
16 available data, to include capitalized labor in the A&G allocation factor.<sup>54</sup> That admission  
17 undercuts TURN's current adjustment. The absence of a functional capitalized-labor breakout  
18 does not justify replacing 20% of a labor allocator with a plant allocator. It only supports a  
19 prospective request for additional details.

20 Nor should plant-in-service be imported into the A&G allocator without record support.  
21 Plant is already used to allocate capital-related costs, including return, depreciation, and taxes.  
22 Using plant again to allocate A&G would blend capital intensity into an operating-support  
23 allocator without evidence that plant, rather than labor, drives those A&G costs. TURN's  
24 proposal is therefore not more cost-based; it is an arbitrary rate-shifting adjustment.

25 The Commission should retain Applicants' labor-based allocation for A&G and  
26 General/Common Plant in this proceeding. Applicants will consider whether additional detail  
27 should be provided in a future CAP, but TURN's 80/20 A&G proposal should be rejected as

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<sup>52</sup> *Id.* at 79.

<sup>53</sup> *Id.* at 44.

<sup>54</sup> *Id.* at 42.

1 unsupported, arbitrary, and inconsistent with the recorded labor-based methodology used in  
2 Applicants' Chapter 8 proposal.

3 This concludes our rebuttal testimony.