APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY & SAN DIEGO GAS & ELECTRIC COMPANY FOR AUTHORITY TO REVISE THEIR NATURAL GAS RATES AND IMPLEMENT STORAGE PROPOSALS IN THE 2024 COST ALLOCATION PROCEEDING

(A.22-09-015)

(DATA REQUEST TURN-SEU-6)
DATA RECEIVED: AUGUT 7, 2023
DATE RESPONDED: AUGUST 21, 2023

QUESTION 1:

1. Re: Chapter 15: Please briefly explain how each of the two scenarios described below would individually impact the company's proposed total capacities for inventory, injection and withdrawal, and the company's proposed allocation of those capacities to the various storage services:
   a. Assume the 7/28/23 proposed decision in the Aliso Canyon Investigation (I.17- 02-002) is approved and the allowed Aliso inventory is increased to 68.6 Bcf.

      RESPONSE 1a:
      SoCal Gas' proposal, described in Chapter 1 section VII, allocates any change in capacity using the percentages shown in Table 5.

   b. Assume the Aliso Canyon Withdrawal Protocol were eliminated, as proposed in the SEU's 4/19/23 letter to Energy Division.

      RESPONSE 1b:
      Please see Response 1a.

QUESTION 2:

2. Re: Chapter 15, page 7: In his direct testimony, TURN witness Florio made two discrete but linked proposals to: 1) increase the proposed cap on the amount of gas that balancing customers can in aggregate "borrow" from other storage customers from the 2.5 Bcf proposed by the company to 5 Bcf; and 2) no longer allocate load balancing inventory costs to core customers. No other operational or regulatory changes were proposed. At page 7, lines 8-9 of its rebuttal, the company states that: "Given the vagueness of this proposal, it should be rejected."
   a. What does the company find to be "vague" about Mr. Florio's two proposals?

      RESPONSE 2a:
      SoCalGas understands the first proposal, and SoCalGas has no comments on it. SoCalGas comments refer only to the second proposal.

      The TURN proposal to "excuse core customers from paying for Load Balancing inventory costs" appears to rest on the assumption that balancing customers impose costs on Core customers that are equal to the cost of the balancing inventory Core customers may use. TURN's contention is that balancing customers may impose costs on Core customers by "loaning" gas owned by Core customers, and by using storage capacity allocated to the Core. However, TURN's proposal only vaguely alludes to those potential costs without quantifying them, ensuring that they exist, and verifying that they are sufficiently large enough to support their proposal. SoCalGas believes that the expected value of these costs to Core customers during the CAP period is zero; however, SoCalGas also believes that these costs cannot be estimated with sufficient certainty to be allocated.

   b. What other details or specifications would the company need to have in order to rectify the "vagueness" it found in Mr. Florio's two proposals?

      RESPONSE 2b:
      Core customers should only be compensated for the costs that balancing customers may impose on them. Therefore, TURN would have to clearly identify and quantify the costs that imbalance customers are expected to impose on Core customers in a manner that is reasonable, actionable, and offers sufficient certainty.

QUESTION 3:

3. Re: Chapter 15, page 7, lines 4-5:
   a. How does the fact that the core may still have access to the shared storage capacity make this proposal “impossible to implement?”

      RESPONSE 3a:
      Balancing customers may impose a cost on Core customers when their actions prevent Core customers from accessing their allocated capacities. To estimate the costs that balancing customers may impose on Core customers, SoCalGas would have to forecast the times that balancing customers interfere with Core customers. As explained in Response 2a, those estimates would have to be made to ensure that TURN’s proposal to “excuse core customers from paying for Load Balancing inventory costs” is warranted.

   b. Does the company contend that the core would still have access to the shared storage capacity at a particular time if it were being used to store cumulative negative imbalances? If so, please explain how the core would have access to that capacity under such circumstances.

      RESPONSE 3b:
      Under most circumstances, the Core has use of all their allocated storage assets, even when the cumulative customer imbalance falls below zero. For example, the Core can inject gas up to their full allocated capacity during their injection season and take advantage of lower prices regardless of the cumulative imbalance position.

QUESTION 4:

4) Re: Chapter 15, page 7, lines 6-8:

a. How would the fact that SoCalGas may not be able to identify in advance the ownership of the gas or the timing of any loan of cumulative customer imbalances make TURN's proposal "impossible to implement?"

RESPONSE 4a:
As explained in Response 2b, Core customers should only be compensated for the costs that balancing customers may impose on them. If some of the costs are the result of "loans" by balancing customers, TURN's proposal requires a reasonable estimate of the fair value of the loans. This can only be done by identifying the timing of the loan and the title of the "loaned" gas.

b. Why would it matter that SoCalGas may not be able to determine in advance whether cumulative customer imbalances will stay positive for the entire CAP period?

RESPONSE 4b:
As explained in Response 2b, Core customers should only be compensated for the costs that balancing customers may impose on them. As explained in Response 2a, TURN's contention is that balancing customers may impose costs on Core customers by "loaning" gas owned by Core customers, and by using storage capacity allocated to the Core. Neither of these potential costs can occur when the cumulative customer imbalance is positive. If the cumulative customer imbalance remains positive for the entire CAP period, the expected costs that imbalance customers impose on Core customers is zero and no compensation is required.

c. Isn't it the case that core customers did not pay for Load Balancing Inventory costs prior to D.16-06-039?

RESPONSE 4c:
Yes. Decision (D.)16-06-039, pages 41-42 state "SoCalGas and SDG&E propose one minor change to the methods set forth in D.14-06-007 as it relates to load balancing inventory. They propose that load balancing inventory now be allocated to the core in order to provide the core with the same access to **load balancing** inventory that other customers have available to them.

QUESTION 5:

5) Re: Chapter 17, pages 2-3: Please explain precisely which escalation factors from GRC Exhibits SCG-36 and SCG-40-2R-E the SEUs propose to use to escalate transmission and storage embedded costs in the rate case attrition years (assuming that the numbers in those two exhibits are adopted as proposed). If you answer does not correspond with the figures shown in Exhibit SCG-40-2R-E, Tables KN-2, 3, 4 and 6, please explain why not.

RESPONSE 5:
For SoCalGas: Exhibit SCG-36-page SRW-5, Table SRW-2, see row Post -Test Year GOMPI for O&M Cost Escalation Indexes, and for Capital-Related see last table row, Total Gas Plant Escalation Indexes.

For SDG&E: Capital escalation rates are the same as for SoCalGas
O&M escalation rates can be found Ch.8 testimony footnote 62, or Exhibit SDG&E -41, page SRW-6, Table SRW-2, see row Operation and Maintenance Post-Test year GEOMPI.

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QUESTION 6:

6) Re: Chapter 17, page 3 and Chapter 18, page 9:
   a. Please explain how, when preparing its FERC Form 2, the company converts costs from its internal "cost centers" to the FERC Uniform System of Accounts. Are the factors shown in Appendix C of GRC Exhibit SCG-39-2R used in the process? If so, please explain how. If not, please explain what other methodology is used for such conversion.

RESPONSE 6a:
When preparing the FERC Form 2 Filing, the costs are charged to specific general ledger accounts and internal orders which are then mapped to the appropriate FERC accounts. The factors shown in Appendix C (GRC Exhibit SCG-39-2R) are only used in the GRC proceeding. These factors are derived using a cost center historical analysis so that the appropriate reassignment factors can be applied to the forecasted non-shared and shared service O&M expenses.

   b. Is there any reason why the factors shown in Appendix C of GRC Exhibit SCG- 39-2R could not be used to convert the costs *authorized in the GRC* to the appropriate FERC accounts? If so, please identify and explain each such reason.

RESPONSE 6b:
As explained in Response 6a, the purpose of the SoCalGas derived factors is to ensure on a forecast basis the correct amount of costs are reassigned to capital for overhead loading. In the GRC, SoCalGas requests and presents its direct O&M expense forecasts using cost centers and workpaper groups (groupings of cost centers).

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QUESTION 7:

7. Re: Chapter 17, page 3: Under Mr. Florio's proposal, when converting authorized 2024 GRC revenue requirements to FERC accounts, why couldn't Pipeline Safety Enhancement Program (PSEP) costs be excluded, as the company does in its own embedded cost study, and then either allocated directly to customer classes through balancing account amortization or be removed from the GRC base margin and reallocated functionally based on the GRC PSEP costs, to address any potential double-counting issue? Would the company accept subject to check that this was Mr. Florio's intent?

RESPONSE 7:

Applicants object on the grounds that the request calls for Applicants to speculate as to Mr. Florio's intentions in creating his testimony in this proceeding. Subject to and without waiving the foregoing, Applicants respond as follows: it is feasible to quantify the revenue requirement associated with the Pipeline Safety Enhancement Program (PSEP) in the GRC. However, the Results of Operations (RO) model lacks the required level of granularity to segregate transmission and storage revenue requirements at the total company level, as proposed by Mr. Florio.

QUESTION 8:

8. Re: Chapter 17, pages 4-5: Please explain in detail how and why applying the percentage of *EG demand* served directly from the backbone to *the total system throughput* (not just EG throughput) accurately represents the demand supported directly from the backbone.

RESPONSE 8:
The percent that is applied to the total system throughput is a representation of demand that is directly off backbone. This method is one of the ways to propose to reallocate cost and is the method that SoCalGas has chosen to use because the transmission backbone carries more than just electric generation supply.

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QUESTION 9:

9. Re: Chapter 17, pages 4-5: Was the methodology introduced by SoCalGas in A.08-02-001 ever adopted by the Commission for purposes of cost allocation? Why has the company waited over a decade since D.11-04-032 to make this proposal here?

RESPONSE 9:
It was not denied or adopted in D.11-04-032.

Factors that contributed to Applicants making the proposal in this proceeding include comprehensive research and data analysis, the complexity of the analysis, and consideration of timing.

QUESTION 10:

10. Re: Chapter 17, page 7: Has the company used embedded costs consistently for cost allocation since D.86-12-009, or was there a period of time during which LRMC was used for all functions for purposes of cost allocation?

RESPONSE 10:
No. In December 1992, the Commission adopted the LRMC methodology in D.92-12-058 for the three gas utilities—Pacific Gas and Electric Company (PG&E), SoCalGas, and SDG&E. Additionally, the Commission adopted the total investment method to calculate the marginal capital costs for Transmission and Storage.

D.09-11-006 (page 3) adopted embedded cost allocation for transmission and storage facilities and long-run marginal cost (“LRMC”) allocation for distribution facilities for both SDG&E and SoCalGas.

QUESTION 11:

11. Re: Chapter 17, pages 8-9: Please identify and briefly explain any part of "the significant variation in total depreciation expense for the test year 2024" that is not simply based on the differences in depreciation forecasts presented by the various parties in the GRC. Please explain whether the Sempra utilities anticipate that the Commission's decision in the test year 2024 GRC will resolve the variation and, if not, why not.

RESPONSE 11:

Applicants object to the request to the extent it asks Applicants to speculate what the Commission may determine in the GRC proceeding. Such a speculative request also is improper inasmuch as it seeks a legal conclusion and seeks information beyond the scope of this proceeding.

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QUESTION 12:

12. Re: Chapter 17, pages 9-10:

a. Is it not the case that the amount of gas required to be stored in inventory is a function of the amount of withdrawal that may need to occur over a given day and a given winter season? Please explain your answer.

RESPONSE 12a:
Applicants object to this request on the grounds the phrase "amount of withdrawal" is vague and ambiguous. Subject to and without waiving the foregoing, Applicants respond as follows.

No, the allocated withdrawal amounts are not a function of the inventory required.

b. Would SoCalGas store additional gas in inventory for which it did not foresee any need to withdraw (other than cushion gas)? If the response is anything other than an unqualified negative, please explain the answer, including identifying the conditions under which such storage would occur.

RESPONSE 12b:
No.

QUESTION 13:

13. Re: Chapter 17, page 10: Please provide the basis for the statement that: "The capital assets associated with Account 351 (Structures and Improvements) and Account 357 (Other Equipment) primarily serve the purpose of providing a working gas inventory." Aren't workers whose duties include injection and withdrawal stationed in Account 351 structures?

RESPONSE 13:

Yes. Storage operations experts analyzed the various activities and compiled information required to form the basis for the functionalization and allocation of costs based on cost causation principles.

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QUESTION 14:

14. Re: Chapter 17, page 11, Accounting example on lines 12-14:
   a. Is an Asset Retirement Obligation (Liability) always matched with an equal and offsetting Asset Retirement Cost (Asset) on the company's books? If not, please explain when and how these values might differ.

RESPONSE 14a:

No, the balance for Asset Retirement Obligation (ARO) does not always match the balance for Asset Retirement Cost (ARC). Their balances generally only match upon initial recognition of ARO liability in the general ledger. However, monthly accretion expenses recognized in the general ledger increase the ARO liability, while not having any impact on the ARC. ARC balance changes only if there is any disposal or addition to the ARO asset or if there's a revision in date of disposal or in estimated disposal cost.

(Accretion: monthly increase in ARO balance based on discount rate. The ARO balance will gradually grow until it equals the future cash flow amounts.)

   b. Do these entries for Asset Retirement Obligation or Asset Retirement Cost have any impact on the company's net income? If the response is anything other than an unqualified negative, please identify and briefly describe the circumstances or conditions under which the entries would have an impact on the company's net income.

RESPONSE 14b:

No, journal entries for ARO and ARC are related to utility assets and do not impact the utility's net income.

c. Do these entries for Asset Retirement Obligation or Asset Retirement Cost have any impact on the company's authorized revenue requirement? If the response is anything other than an unqualified negative, please identify and briefly describe the circumstances or conditions under which the entries would have an impact on the company's authorized revenue requirement.

RESPONSE 14c:
No, entries on ARO or ARC do not have an impact on the company's authorized revenue requirement. See Response 14b.

QUESTION 15:

15. Chapter 17, page 11, line 17, states that "depreciation . . . is the return *of* capital."

a. In the case of cost of removal (or asset retirement cost), wouldn't it be more accurate to say that depreciation is not the return of capital but rather the provision of capital to cover a future obligation? Please explain fully.

RESPONSE 15a:

Depreciation has several components. Depreciation allocates the cost of the asset which results in the return of capital, including any estimated salvage/cost of removal to retire the asset in the future, as an ongoing cost of operations, over the economic life of the asset.

b. In the case of a cost of removal (or asset retirement cost) that is included in authorized depreciation expense, what "capital" is being returned at the time the amount is collected?

RESPONSE 15b:

See Response 15a.

QUESTION 16:

16. Re: Chapter 18, page 2 states that: "SoCalGas and SDG&E only applied the line extension cap to the residential customer class in their Customer Cost Studies. The line extension allowances do not impact the other customer classes' capital costs."

   a. Doesn't this mean that the *entire cost* of line extensions for other customer classes are included in the derivation of marginal customer costs, without any capping? If not, please explain.

   RESPONSE 16a:
   The line extension allowances used in the calculation of marginal costs are only applicable to the single family and multi-family residential class of customers.

   b. Doesn't D.22-09-026 mean that line extension allowances will be capped at zero for all customer classes going forward from June 30, 2023, except for special cases approved by the Commission? If not, please explain.

   RESPONSE 16b:

   SoCalGas' Rule 20 (GAS_G-RULES_20.pdf (socalgas.com)) discusses the extension allowances impacted by D.22-09- 026. For Eligible Projects approved by the Commission, allowances shall be granted to an Applicant for nonresidential Permanent Service; or to an Applicant for a non-residential subdivision or development.

   Transmission level noncore customers pay their own customer-specific costs and are not impacted by D.22-09-026.

QUESTION 17:

17. Re: Chapter 18, page 3 states that SoCalGas had 9,069 line extension allowance applications from January 1, 2022 to June 30, 2022. How many of those extensions were actually completed in Q3 2022, Q4 2022, Q1 2023 and Q2 2023? How many were still pending on June 30, 2023? Of the "12,328 pending residential construction projects, based on line extension allowances applications from January 1, 2023 to June 30, 2023" how many does SoCalGas forecast to complete in the second half of 2023, in all of 2024 and in each year thereafter?

RESPONSE 17:
The data requested is unavailable. SoCalGas provides the following data on signed contracts:

- Q1-2022 = 2416
- Q2-2022 = 2864
- Q3-2022 = 2677
- Q4-2022 = 2475
- Q1-2023 = 2609
- Q2-2023 = 2808

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QUESTION 18:

18. Please provide all emails or other materials, including any presentations or slides provided during meetings, sent to SoCalGas management, director level or above, related to the effects of D.22-09-026 and the Commission's policy to eliminate gas line extension allowances. Please make sure the presentations are full and complete decks, and the emails provided are complete. Please provide both confidential and redacted versions.

RESPONSE 18:

Applicants object to this request to the extent it seeks the production of information that is neither relevant to the subject matter involved in this cost allocation proceeding nor is reasonably calculated to lead to the discovery of admissible evidence, particularly with regard to the request for "emails" or "materials." Applicants also object to this request as overly broad and burdensome, and object on the ground the phrase "all emails, materials, . . . provided during meetings, to SoCalGas management, director level or above" is vague and ambiguous. Subject to and without waiving the foregoing objections, Applicants respond as follows: Please see attachments TURN-06_Q18_Att1 and TURN-06_Q18_Att2.

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QUESTION 19:

19. Chapter 18, page 3 recommends: "For the next CAP, shifting to a more universal embedded cost approach to ratemaking." Could the SEUs implement this recommendation in this CAP for 2024? If not, what data would be needed that are not available now? Please explain in detail how such a study would be performed, including the data sets that would be used. More specifically, would SoCalGas use a past year's recorded historical costs to do an embedded cost study for all functions? If so, how would those results be reconciled with a future test year revenue requirement?

RESPONSE 19:

The Applicants could not implement the recommendation for a more universal embedded cost approach in this CAP for 2024, that would encompass all functional areas, including but not limited to distribution, customer costs, storage, and transmission. The implementation of such an approach necessitates the allocation of data between distribution and customer costs, as well as the allocation between various customer classes for customer costs.

The proposed study would be conducted in a manner analogous to the Transmission and Storage embedded study. SoCalGas would employ the recorded historical costs of a previous fiscal year to undertake an embedded cost study that encompasses all functional areas. It is imperative to note that SoCalGas requires a minimum period of one year to develop the initial model from the time of the availability of FERC Forms 1 & 2, and in coordination with GRC updated base year data that Transmission and Storage utilizes for tax (state, federal, ad valorem, and payroll) purposes, particularly if the studies are to be updated with more recent data. The scalar shall be employed to reconcile these results with the revenue requirements of a prospective test year.