BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U 902 M) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019.	Application No. 17-10-007 (Filed October 6, 2017)
And Related Matter.	Application No. 17-10-008 (Filed October 6, 2017)

JOINT PETITION FOR MODIFICATION OF D.19-09-051 OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902 M)

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TABLE OF CONTENTS

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I. INTRODUCTION

In accordance with Rule 16.4 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and Decision ("D.") 20-01-002, Southern California Gas Company ("SoCalGas") and San Diego Gas & Electric Company ("SDG&E") (collectively, "Petitioners"), hereby jointly petition the Commission to modify D.19-09-051 (the "2019 GRC Decision"), the final decision in their consolidated test year ("TY") 2019 General Rate Case ("GRC") proceedings.[1] For the reasons stated herein, Petitioners request relief implementing third and fourth attrition years 2022 and 2023, consistent with the Commission's recent decision in Rulemaking ("R.") 13-11-006 (the "Rate Case Plan" or "RCP" Rulemaking), D.20-01-002 (hereinafter referred to as the "RCP Decision").

For the additional attrition years 2022 and 2023, SoCalGas and SDG&E request that the Commission adopt a continuation of their currently authorized post-test year ("PTY") mechanism,[2] which is supported by the evidentiary record and the 2019 GRC Decision in this

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[1] This Joint Petition is timely filed and served within one year of the effective date of D.19-09-051, consistent with Rule 16.4(d).
[2] *See* D.19-09-051 at 16-17.

proceeding, and by the attached declarations of joint SoCalGas and SDG&E witness Ryan Hom (Attachment A), SDG&E witness Kenneth Deremer (Attachment B), SoCalGas witnesses Jesse Aragon (Attachment C) and Deana Ng (Attachment D), consistent with Rule 16.4(b).

Attachments A through D also provide the evidentiary support that fulfills the Commission's requirements to provide detailed information regarding their revenue requirement requests for two additional attrition years.[3] Specifically, proposals are included to update the uncollectible rates, cost escalation factors, and authorized rates of return and to extend the post-test year mechanisms (including for the Pipeline Safety Enhancement Plan ("PSEP") for SoCalGas) adopted in the 2019 GRC Decision. Petitioners also provide their required plan for the procedural disposition of Investigation ("I.") 19-11-010 and I.19-11-011 (the "2019 RAMP Proceeding") and for the submission of their next RAMP applications, in support of their upcoming TY 2024 GRCs, as well as RAMP-related information to support the evaluation of their 2022 and 2023 attrition year proposals, as the RCP Decision requires.[4] The Petitioners' proposed specific revisions "to carry out all requested modifications to the decision," pursuant to Rule 16.4(b), are set forth in Attachment E.

II. PROCEDURAL HISTORY – BACKGROUND

The instant petition for modification ("Petition or PFM") meets the RCP Decision's requirement for SoCalGas and SDG&E to file a PFM consistent with the 2019 GRC Decision, as well as additional RCP Decision requirements. The procedural background requiring and shaping the content of this joint PFM is described below, in relevant part.

[3] D.20-01-002 at 52.
[4] *Id.* at 52-53.

A. SoCalGas' and SDG&E's TY 2019 GRC Showing Was Informed by Their 2016 RAMP Report.

On November 30, 2016, SDG&E and SoCalGas filed their RAMP report ("2016 RAMP Report") that would inform the above-captioned TY 2019 GRC proceeding, in I.16-10-015/-016. As explained in the 2019 GRC Decision, the application and supporting testimony in this proceeding was "the first by a regulated utility to fully incorporate risk mitigation activities using the risk-informed framework developed by the Commission in the Safety Modeling Assessment Proceeding (S-MAP) and the Applicants' RAMP proceeding."[5] SDG&E and SoCalGas incorporated the results of the 2016 RAMP Reports into their respective TY 2019 GRC applications and testimony chapters, as described in their RAMP to GRC Integration testimony.[6] Each GRC witness sponsoring RAMP-related activities also dedicated sections in their testimony to addressing RAMP, explaining which risk(s) are covered and how the mitigation activities impact the risk(s), presenting a table showing the forecasted RAMP requests and the workpaper, providing a qualitative discussion of the benefit of the sponsored mitigation activities, and discussing any alternatives that were considered.[7] As the 2019 GRC Decision explained,

> Applicants submitted testimony providing a roadmap of the RAMP risks that were incorporated into this GRC application. The testimony also provided context on viewing the funding requests through the lens of risk management. Testimony that incorporates RAMP-identified risks presents the proposed spending as a risk mitigation activity.[8]

The TY 2019 GRC differed from those filed before it, not only because of the introduction of the RAMP, but also in the Petitioners' approach and preparation, as SoCalGas' and SDG&E's Risk Management and Policy testimony explained:

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[5] D.19-09-051 at 20.
[6] Ex. 3 (SoCalGas/SDG&E/York Direct), *passim*; *see also* D.18-04-016 at 1-2, 14.
[7] *See* SoCalGas' and SDG&E's direct testimony presentation, *passim*; *see also* D.18-04-016 at 11-12.
[8] D.19-09-051 at 20.

> The RAMP process involved multiple organizations throughout the Companies reviewing, assessing, and analyzing the safety risks and associated mitigation plans in significant detail, which provided a new risk perspective in the context of GRC preparation. This multi-organizational evaluation during the RAMP and GRC planning processes revealed some risk exposure that may be mitigated by implementing new projects or expanding existing projects or programs.
>
> In that sense, the RAMP process, and the models presented in the S-MAP, worked as intended and was constructive in identifying potential mitigants to further reduce risk to employees, contractors, and the public. The analysis resulting from the RAMP process helped shape this GRC request, and the Companies are seeking funding for incremental activities to provide additional risk mitigation...[9]

In the decision closing I.16-10-015/-016, D.18-04-016, the Commission recognized the positive, valuable impacts of the 2016 RAMP Reports on SoCalGas and SDG&E's risk management procedures and TY 2019 testimony showing:

> Testimony included in the Test Year 2019 GRC applications contain sections pertaining to RAMP and an assessment of feedback from the RAMP process. Proposed spending for safety mitigation activities and the efficiency of risk mitigation funding are to be reviewed in the Test Year 2019 GRC applications. The RAMP process had positive impacts on SDG&E's and SoCalGas' risk management procedures. Key safety risks and proposed mitigation activities were more thoroughly reviewed, assessed, and analyzed. The RAMP process brings safety to the forefront so that potential mitigations and proposed spending to further reduce risk to the public, employees, and contractors can be more thoroughly reviewed in the GRC applications.[10]

And the 2019 GRC Decision noted that, "[i]n reviewing the RAMP-driven portions of witness testimony in this GRC, we find that many of the activities identified by Applicants as flowing from the RAMP and mitigating risk are activities that were already being performed by Applicants and were included in prior GRCs"[11] and concluded that "[m]any of these programs are being approved and the funding allows SDG&E and SoCalGas to perform increased mitigation efforts to mitigate key safety risks."[12] Further, the 2019 GRC Decision explained that

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[9] Ex. 3 (SoCalGas/SDG&E Day Revised Direct) at DD-18.
[10] D.18-04-016 at 1-2.
[11] D.19-09-051 at 21-22.
[12] *Id.* at 4.

the Commission's continuing developments in S-MAP and RAMP are refining processes for risk mitigation analysis, accountability reporting and measurements on an ongoing basis:

> The SMAP, RAMP, and spending accountability process to integrate risk mitigation activities into the GRC began in 2014 and is still being refined. In April 2019, the Commission adopted 26 safety metrics for which utilities are to report their progress toward the risk mitigation goals set out in the GRCs. In addition, the recently closed and future SMAP proceedings have evaluated and will continue to evaluate the minimum elements to be used by large utilities for risk mitigation analysis in future RAMP and GRC applications. The Commission also approved improvements to Risk Mitigation Accountability and the Risk Spending Accountability reports, which will require additional internal tracking processes and tools to measure how well identified risks are actually being mitigated, and the risk reduced per dollar spent.[13]

B. The 2019 GRC Decision Approved a Ratemaking Mechanism for the TY 2019 Post-Test Years and Deferred a Ruling on a Third Attrition Year to the Rate Case Plan Rulemaking.

1. SoCalGas' and SDG&E's Authorized Post-Test Year Ratemaking Mechanism

For post-test years 2020 and 2021, the 2019 GRC Decision approved a two-part attrition mechanism for SoCalGas and SDG&E that separately escalates capital-related revenues and Operations and Maintenance ("O&M") expenses.[14] The Commission authorized the post-test year mechanism as part of an extensive review of the record evidence in this proceeding, including various proposals presented by different parties.[15] The authorized attrition mechanism is based on the following:

- **Capital Adjustment:** seven-year recorded and forecasted cost of capital additions (2013-2019) that are escalated using IHS Markit Global Insight ("Global Insight") indices to 2019 dollars and then averaged; 2020 and 2021 are

[13] *Id.* at 21 (citations omitted).
[14] D.19-09-051 at 705; Attachment B (Deremer) at 2-3; Attachment C (Aragon) at 2-3.
[15] D.19-09-051 at 705-706.

determined by escalating the seven-year average using the Global Insight indices.[16]

- **O&M Adjustment:** labor and non-labor (including medical) O&M are escalated using Global Insight indices.[17]

The 2019 GRC Decision also approved the continuation of SoCalGas' and SDG&E's previously authorized Z-Factor mechanisms,[18] among other determinations that would continue during the post-test years, as discussed further below.

The 2019 GRC Decision denied SoCalGas and SDG&E's request for a four-year GRC term from 2019-2022 (with the next GRC cycle beginning with TY 2023), noting that "the appropriate term for the GRC cycle is currently being considered in Rulemaking (R.) 13-11-006 and the decision defers any decision regarding this issue to R.13-11-006."[19] However, the 2019 GRC Decision acknowledged that a PFM would need to be filed to address the evidence supporting an additional attrition year, if a four-year GRC cycle were adopted in the RCP Rulemaking:

> Finally, the decision denies Applicants' requests to include a third PTY (2022) in their respective GRC cycles. The decision finds that a determination as to whether a three-year or four-year GRC cycle should be adopted must be applied uniformly to all large investor owned utilities that are regulated by the Commission. In addition, the appropriate term for the GRC cycle is currently being considered in Rulemaking (R.) 13-11-006 and the decision defers any decision regarding this issue to R.13-11-006. If a decision adopting a four-year GRC cycle is made in R.13-11-006, SDG&E and SoCalGas are required to file a petition to modify this decision.[20]

[16] *Id.* at 708-710.
[17] *Id.* at 708.
[18] *Id.*, Ordering Paragraph ("OP") 4 at 776.
[19] *Id.* at 6.
[20] *Id.* at 6.

2. SoCalGas' Authorized PSEP Post-Test Year Ratemaking Mechanism

For the PSEP, SoCalGas presented detailed estimates to complete eleven pressure test projects, eleven PSEP replacement projects, and 284 PSEP valve projects, which were expected to be completed in the three-year (2019-2021) GRC cycle,[21] and requested recovery of the associated revenue requirement through a two-way balancing account mechanism.[22] SoCalGas also provided support for additional PSEP projects for a third post-test year (with projects forecasted to be completed in 2022), if the request for an additional attrition year had been approved in this proceeding.[23]

As explained in SoCalGas' 2019 GRC testimony, PSEP projects were developed using a risk-informed prioritization methodology:

> As directed by the Commission, the SoCalGas and SDG&E PSEP includes a risk-based prioritization methodology that prioritizes pipelines located in more populated areas ahead of pipelines located in less populated areas and further prioritizes pipelines operated at higher stress levels above those operated at lower stress levels. This prioritization directive and the goals to enhance public safety, comply with Commission directives, minimize customer impacts, and maximize the cost effectiveness of safety investments have led to the development of the PSEP mitigation described in the RAMP.[24]

This methodology was contested by parties and fully litigated in the 2019 GRC proceeding. In the 2019 GRC Decision, the Commission found "SoCalGas' method and cost

[21] Ex. 231 (SoCalGas Philips Direct) at RDP-A-22. In compliance with Ordering Paragraph 5 of D.16-08-003, SoCalGas incorporated PSEP projects into the TY2019 GRC. Since the majority of PSEP work was projected to be completed after the 2019 Test Year, a revenue requirement adder was developed specifically for PSEP capital in the post test years. The TY2019 O&M forecast was an average of the projected level of PSEP O&M over the 2019 – 2021 period.
[22] Attachment D (Ng) at ¶ 5.
[23] *See* Ex. 231 (SoCalGas Philips Direct) at Section X and XI.
[24] *Id.* at RDP-A-18 – RDP-A-19.

estimates to be reasonable, appropriate for the proposed projects, and supported by the testimony submitted."[25]

The 2019 GRC Decision authorized revenue requirements for 2019-2021 associated with SoCalGas' forecasts for nine of the proposed PSEP pressure test projects, ten of the proposed PSEP replacement projects, and 284 of the proposed valve project bundles subject to a ten-percentage point reduction of a risk assessment component of the cost estimates.[26] The 2019 GRC Decision also authorized a separate revenue requirement in the post-test years for PSEP based on capital additions forecasted beyond TY 2019:

> We also find SoCalGas' proposal that PSEP capital-related costs not fully reflected in the TY2019 revenue requirement be included as part of the PTYs reasonable and we approve it. This is because PSEP is being incorporated into the GRC for the first time and timing and completion of the proposed projects should not be delayed. We find the adjustment necessary in order to fully reflect the capital costs we are authorizing but will not be fully reflected in the TY.[27]

Because the Decision opted to refer the question of the third attrition year to the RCP Rulemaking, the 2019 GRC Decision did not consider SoCalGas' 2022 proposals, including PSEP-related requests.[28]

C. SoCalGas and SDG&E Filed their 2019 RAMP Reports, in Anticipation of a TY 2022 GRC.

Following issuance of the 2019 GRC Decision, on November 20, 2019, Orders Instituting Investigations were issued for SoCalGas and SDG&E in the 2019 RAMP Proceeding, "to address the risk assessment approach that SoCalGas plans to use in its upcoming TY2022 GRC

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[25] D.19-09-051 at 204.
[26] Attachment D (Ng) at ¶ 8 (citing D.19-09-051, Conclusions of Law ("COL") 43, 44 at 766).
[27] D.19-09-051 at 215-216.
[28] *See* D.19-09-051 at 30 ("Proposals under various topics as well as testimony and other evidence made in those proceedings concerning 2022 are not discussed further in this decision.").

application."[29] SoCalGas and SDG&E tendered for filing their RAMP reports in those proceedings on November 27, 2019 (herein referred to as "2019 RAMP Report").[30] The 2019 RAMP Report reflects SoCalGas' and SDG&E's planned intentions to request funding for risk mitigation projects and activities (in their then-anticipated TY 2022 GRC), as of the time of filing. In the typical disposition of a RAMP proceeding, the activities described in the RAMP Report would be integrated into SoCalGas' and SDG&E's next respective GRC application, following a Safety and Enforcement Division ("SED") evaluation report and comment period. No final decision results from a RAMP proceeding.[31]

D. The Rate Case Plan Decision Requires SoCalGas and SDG&E to File the Instant PFM, with 2022 and 2023 Attrition Year and RAMP-Related Proposals.

On January 16, 2020, the Commission approved the RCP Decision, D.20-01-002, extending the GRC cycle for each investor-owned utility ("IOU") from three to four years and implementing changes to conduct GRC proceedings more efficiently. For SoCalGas' and SDG&E's current GRC cycle, the Commission designated 2022 and 2023 as additional attrition years and 2024 as the next GRC test year,[32] and required SoCalGas and SDG&E to propose attrition year increases in a PFM of the TY 2019 GRC Decision.[33] The RCP Decision requires

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[29] I.19-11-010/-011 (cons.), Order Instituting Investigation into Southern California Gas Company's Risk Assessment and Mitigation Phase November 2019 Submission (November 7, 2019) at 4.
[30] *See* I.19-11-010/-011 (cons.), Joint 2019 Risk Assessment and Mitigation Phase Report of SoCalGas and SDG&E (November 27, 2019).
[31] D.18-04-016 at 5 ("As described in D.14-12-025, no decision is expected to be issued in these proceedings and this decision only serves to close out these RAMP OIIs.") (citation omitted); D.14-12-025 at 36 ("No Commission decision would be issued in connection with the RAMP.").
[32] D.20-01-012 at 3, 53.
[33] *Id.* at 3, 52.

SoCalGas and SDG&E to file the PFM consistent with D.19-09-051,[34] "as soon as practicable,"[35] and to include the following components:

> SoCalGas and SDG&E shall include in their petition detailed information to enable the Commission and interested parties to evaluate the utilities' requested revenue requirements for the two additional attrition years, including but not limited to: proposed escalation factors, anticipated Pipeline Safety Enhancement Plan and other capital projects for 2022 and 2023, and updates to all relevant forecasts from their 2019 GRC applications.[36]

The PFM should also include certain RAMP-related "information and procedural proposals":

> [The] petition for modification of D.19-09-051 should provide RAMP-related information and procedural proposals to (1) support the Commission's evaluation of their 2022 and 2023 attrition year proposals; (2) suggest a procedural disposition for I.19-11-010 and I.19-11-011; and (3) explain to the Commission and interested parties how the utilities intend to submit their RAMP applications in support of their test year 2024 GRCs.[37]

The RCP Decision further moves SoCalGas' and SDG&E's next RAMP filing date to May 15, 2021 and their next GRC application filing date to May 15, 2022.[38]

E. SoCalGas and SDG&E Have Proposed an Expeditious Resolution to the 2019 RAMP Proceeding, with the Support of the Majority of RAMP Parties.

After the RCP Decision was issued, on January 23, 2020, Administrative Law Judge ("ALJ") Lirag issued a Ruling Setting Prehearing Conference Schedule in the 2019 RAMP Proceeding, requiring SoCalGas and SDG&E to submit a prehearing conference statement regarding a proposed proceeding schedule and the impact of the RCP Decision on the 2019 RAMP Proceeding. On February 12, SoCalGas and SDG&E filed a Joint Prehearing Conference

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[34] *See* D.19-09-051, OP 33 at 784, "If a decision adopting a four-year General Rate Case cycle is made in Rulemaking 13-11-006, Southern California Gas Company and San Diego Gas & Electric Company shall file a petition for modification of this decision to request review and implementation of Southern California Gas Company's and San Diego Gas & Electric Company's post-test year proposals for 2022."
[35] D.20-01-012 at 55.
[36] *Id.* at 52-53.
[37] *Id.* at 53.
[38] *Id.* at 55.

Statement that presented two alternative schedules for an expeditious procedural disposition of the 2019 RAMP proceedings: Alternative 1, which provided parties the opportunity to comment on the 2019 RAMP Reports before closing, and Alternative 2, which would schedule a close to the proceeding without further activity. The majority of parties in that proceeding[39] either supported or did not take issue with closing the proceeding by adoption of one of the two alternatives.[40]

On February 26, 2020, the Commission held a prehearing conference ("PHC") in the 2019 RAMP Proceeding. At the PHC, POC requested party status and stated an objection to closing the proceeding, offering indeterminate ideas to keep the proceeding open and/or consolidate it with review of the instant required PFM filing, which will establish revenue requirement increases in the newly adopted attrition years 2022 and 2023. In response to the question from ALJ Lirag, "how do you suggest the information will tie in with an attrition year filing?"[41]; POC responded, in relevant part: "[W]e don't have a necessarily position on how best … to achieve that, other than it should be achieved."[42]

UWUA also reiterated objections that were discussed in its PHC Statement, requesting the proceeding be kept open "to evaluate the Gas Companies' RAMP reports compliance and

[39] I.19-11-010/-011 (cons.), Parties to the 2019 RAMP Proceeding are the Commission's Public Advocates Office ("Cal Advocates"), the Utility Reform Network ("TURN"), the Utility Consumers' Action Network ("UCAN"), Mussey Grade Road Alliance ("Mussey Grade"), Utility Workers Union of America, Local Unions 132, 483 and 522 ("UWUA"), Southern California Generation Coalition ("SCGC"), FEITA Bureau of Excellence, LLC ("FEITA"), and Protect Our Communities ("POC").
[40] *See* I.19-11-010/-011 (cons.), SoCalGas and SDG&E's Joint PHC Statement's summary of parties' positions at 10-11; *see also* PHC Statements filed by Cal Advocates, TURN, UCAN, and Mussey Grade.
[41] I.19-11-010/-011 (cons.), Transcript ("Tr.") at 15:28-16:1 (ALJ Lirag).
[42] I.19-11-010/-011 (cons.), Tr. at 16:11-14 (POC/Dickerson).

consistency with S-MAP and the Public Utilities Code."[43] Among other parties supporting the Alternative 1 proposal to close the proceeding, TURN stated:

> TURN actually was the primary intervenor party during the settlement process. … And … TURN provided expert consultants that … helped establish a methodology. … [So] we would be similarly interested in making sure that the methodology used in Sempra's future RAMP is consistent with the settlement, as well as the Commission decision.· But to invest that kind of resource into a RAMP filing that's no longer going to inform the next GRC seems not the best use of public resources.[44]

ALJ Lirag set a briefing schedule to allow parties to (1) comment on whether the RAMP proceeding should be closed, integrated with the instant GRC proceeding, or disposed of in some other way, and (2) allow parties to offer their comments on the RAMP Reports (consistent with SoCalGas' and SDG&E's proposed Alternative 1).

SoCalGas and SDG&E filed their Opening Brief on March 23, 2020, requesting rejection of POC's unspecified proposals to integrate the 2019 RAMP Reports into the PFM in the TY 2019 GRC proceeding, as they are based on a fundamental misunderstanding of the purpose and function of RAMP and the Commission's risk-based decision-making GRC framework – the S-MAP, RAMP and GRC proceedings, and annual accountability reporting requirements. The Commission's risk-informed GRC framework is designed to directly integrate RAMP into an IOU's GRC cost forecasts, not into an IOU's attrition year revenue requirement, and integrating the 2019 RAMP Reports into the TY 2019 GRC proceedings would create a mismatch between SoCalGas' and SDG&E's current and future GRC test year cycles, as well as between Commission processes.[45]

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[43] I.19-11-010/-011 (cons.), UWUA PHC Statement at 5. FEITA also filed a PHC Statement requesting the 2019 RAMP proceedings be kept open for discovery but did not appear at the PHC.
[44] I.19-11-010/-011 (cons.), Tr. at 36:5-16 (TURN/Cheng).
[45] I.19-11-010/-011 (cons.), Opening Brief of SoCalGas and SDG&E (March 23, 2020), *passim.*

TURN and Mussey Grade submitted briefing in support of the proposed Alternative 1 to close the 2019 RAMP Proceeding. FEITA's brief appears to now support SoCalGas' and SDG&E's Alternative 1 proposal. POC and UWUA submitted briefing continuing their support of keeping the 2019 RAMP Proceeding open, while offering no specific proposals on a methodology for use of the 2019 RAMP Reports for use in the instant proceeding.

On April 6, 2020 parties to the 2019 RAMP Proceeding filed response briefs, essentially continuing their above-described positions. Also on April 6, certain parties separately submitted comments on SoCalGas' and SDG&E's November 27, 2019 RAMP submission, consistent with SoCalGas' and SDG&E's proposed Alternative 1 approach (as scheduled by ALJ Lirag at the RAMP PHC). SoCalGas and SDG&E have committed to address parties' comments and feedback in their next RAMP reports, which will be filed in May 2021, pursuant to the RCP Decision. The 2021 RAMP Reports will comply with the S-MAP requirements, will provide direct dollar RAMP forecasts for the years 2022, 2023, and 2024, and will be integrated into SoCalGas' and SDG&E's capital project forecasts for the years 2022, 2023, and 2024, in the next (TY 2024) GRC. The Commission and parties will thus have an opportunity to review RAMP projects and forecasts for 2022, 2023, and 2024 in the 2021 RAMP Reports, as part of the TY 2024 GRC cycle, which will be subject to the full GRC evidentiary process.

III. THE JOINT PFM REQUESTS RELIEF TO ESTABLISH JUST AND REASONABLE 2022 AND 2023 ATTRITION YEAR INCREASES AND PROMOTE AN EFFICIENT TRANSITION TO A LONGER GRC CYCLE.

By this Petition, SoCalGas and SDG&E propose to continue their authorized PTY mechanism into 2022 and 2023. This section, including references to Attachments A-D and accompanying workpapers B.1, C.1, and C.2, provides information in accordance with the RCP Decision's requirement to include:

> detailed information to enable the Commission and interested parties to evaluate the utilities' requested revenue requirements for the two additional attrition years, including but not limited to: proposed escalation factors, anticipated Pipeline Safety Enhancement Plan and other capital projects for 2022 and 2023, and updates to all relevant forecasts from their 2019 GRC applications.[46]

The revenue requirements SoCalGas and SDG&E propose for the additional attrition years 2022 and 2023 are based on the forecasts, results of operations ("RO") model, and PTY mechanism authorized in the 2019 GRC Decision, as well as updated escalation factors from IHS Markit Global Insight ("Global Insight") (approved as reasonable for use in the 2019 GRC Decision),[47] uncollectible rates (updated by the mechanism authorized in the 2019 GRC Decision),[48]) and rates of return (authorized in the Cost of Capital proceeding).[49] As also explained below, SoCalGas' and SDG&E's proposed methodology of using their approved PTY mechanism to provide updates for post-test years 2022 and 2023 is a reasonable and straightforward approach, consistent with Commission precedent for determining attrition year revenue requirements – as opposed to updating individual cost forecasts, which would be unworkable. SoCalGas and SDG&E expect the proposed revenue requirements to allow them to continue safely providing utility service to customers, to maintain adequate system reliability, to provide responsive customer services, to comply with governmental regulations and orders, to recover costs for taxes and depreciation, and to recover revenue necessary to compensate investors for their capital investment in the utility, in the attrition years 2022 and 2023.[50]

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[46] D.20-01-012 at 52-53.
[47] D.19-09-051, Findings of Fact 307 at 761 and COL 108 at 774.
[48] *Id.* at 335-336 and 349-350.
[49] *See generally,* Attachment A (Hom), Attachment B (Deremer), and Attachment C (Aragon).
[50] *See* Attachment A (Hom) at ¶ 6.

A. To Perform the RCP Decision's Required Updates, SoCalGas and SDG&E Updated the 2019 GRC Decision's Authorized Results.

In the 2019 GRC Decision, the Commission conducted an extensive review of SoCalGas' and SDG&E's forecasts and authorized the recovery of reasonable capital costs and expenses necessary for the delivery of safe and reliable service, from January 1, 2019 through December 31, 2021. Through a GRC proceeding, "the Commission authorizes an investor-owned utility to recover through rates the reasonable capital investment costs and annual expenses necessary to operate and maintain its facilities and equipment in a safe and reliable manner."[51] Generally, to develop GRC applications, SoCalGas and SDG&E use historical financial information to forecast costs (in direct dollars) to calculate a test year revenue requirement.[52] These historical and forecasted costs include various projects and activities, such as those associated with the RAMP. As the RCP Decision states:

> The GRC application provides detailed forecasts of the applicant's capital investment expenses and its operating and maintenance (O&M) expenses for a designated 'test year' as well as forecasts for two subsequent post-test years, or 'attrition years.' The Commission's decision is based on its extensive review of the test year forecasts.[53]

The forecasts and revenue requirements authorized in the 2019 GRC Decision are the result of a comprehensively litigated GRC proceeding, which examined each individual forecast request sponsored by witnesses for numerous subject matter areas for both utilities. The robust forecasting GRC process and examination described in the RCP Decision thus has been reflected in the 2019 test year revenue requirement, which forms the basis for determining the 2020 and

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[51] D.20-01-002 at 8.
[52] *See* Attachment A (Hom) at ¶ 8.
[53] D.20-01-002 at 8.

2021 post-test year revenue requirements, through application of the authorized post-test year mechanism.[54]

The RCP Decision describes the general methodology for updating revenue requirement results for attrition years as a formula that is applied to the revenue requirement in successive years, as follows:

> The post-test year revenue requirements are typically determined by (1) escalating the test year O&M expenses, and (2) authorizing capital expenditures at a level determined by either (i) applying additional escalation factors, or (ii) further review of the applicant utility's actual capital budgets for those years.[55]

Here, the 2019 GRC Decision authorized a post-test year ratemaking mechanism that does not use specific, direct cost PTY capital project forecasts to calculate the post-test years' revenue requirements (with the exception of PSEP projects), as explained in more detail in the declarations of Messrs. Deremer and Aragon (Attachments B and C).

For purposes of this Petition, SoCalGas and SDG&E applied the above principles stated in the RCP Decision to "update[] … all relevant forecasts from their 2019 GRC applications,"[56] through use of the authorized post-test year ratemaking mechanism. Specifically, to derive revenue requirements for 2022 and 2023, SoCalGas and SDG&E began with the revenue requirements authorized in the 2019 GRC Decision, and then applied the authorized post-test-year mechanism to "update" the relevant forecasts, including updates for capital projects, by updating the revenue requirement for each consecutive year.[57] SoCalGas and SDG&E also updated the applied uncollectible rate, the Commission-approved cost escalation factors, and the authorized rate of return for 2022 and 2023, as described in Mr. Hom's declaration.[58] This

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[54] *See* Attachment A (Hom) at ¶ 9.
[55] D.20-01-002 at 8.
[56] *Id.* at 53.
[57] Attachment A (Hom) at ¶¶ 11-13.
[58] *Id.* at 4-7.

approach is consistent with both the general methodology described in the RCP Decision (as shown above), as well as with the results of the comprehensively litigated GRC proceeding reflected in the 2019 GRC Decision, which (1) authorized a test year revenue requirement based on a thorough examination of each individual O&M and capital forecast request for both utilities, and (2) authorized a ratemaking mechanism and revenue requirement for the post-test years.

With respect to PSEP capital costs, SoCalGas developed estimates for the 2022 projects included in the GRC Application using the same methodology that was found appropriate and reasonable in the 2019 GRC Decision.[59] Consistent with the Decision, the cost forecast of the Line 44-1008 project[60] was excluded, and the risk assessment component of the other 2022 forecasted projects was reduced by ten percentage points.[61] SoCalGas proposes to use these 2022 capital project forecasts to determine the PSEP capital revenue requirement to be approved for 2022.[62] For 2023 capital for PSEP, SoCalGas proposes continuation of the mechanism authorized in the 2019 GRC Decision, which is being used to derive the rest of the 2023 revenue requirement, as described above.[63]

B. SoCalGas' and SDG&E's Proposed Methodology for Continuing the Currently Authorized Post-Test Year Mechanism for 2022 and 2023.

SoCalGas and SDG&E propose to continue the two-part PTY mechanism authorized in the 2019 GRC Decision to attrition years 2022 and 2023. Consistent with the approved PTY mechanism, SoCalGas' and SDG&E's proposed attrition year 2022 and 2023 increases for non-

[59] Ex. 231 (SoCalGas Philips Direct) at RDP-A-49-RDP-A-54 and 233C (Confidential Supplemental Workpapers to SoCalGas Philips Direct) at 340-420. The 2022 project forecasts were included to support SoCalGas' proposal for a third (2022) attrition year.
[60] D.19-09-051, COL 42 at 766.
[61] *Id.*, COL 44 at 766.
[62] Attachment D (Ng) at ¶ 13.
[63] *See* Attachment C (Aragon) at 7-8.

PSEP capital investments are based on an escalated (using Commission-approved Global Insight indices) seven-year average of capital additions authorized in the 2019 GRC Decision, with updates as described in Mr. Hom's declaration.[64] O&M expenses (including medical) will also continue to be separately escalated using the Global Insight index approved in the 2019 GRC Decision,[65] as updated.

1. SoCalGas' Proposed Revenue Requirements for 2022 and 2023 Are Derived Using the Authorized Post-Test Year Ratemaking Mechanism.

Applying the same post-test year methodology adopted in the 2019 GRC Decision for O&M and non-PSEP capital, as explained above, and making limited updates, yields attrition-year revenue increases of $129.2 million (4.17 percent) in 2022 and $131.4 million (4.07 percent) in 2023, as shown in Table 1 below. Workpapers detailing the post-test year mechanism are attached, as Attachment C.1.

Table 1: SoCalGas Proposed Post-Test Years Attrition Adjustments for O&M and Non-PSEP Capital[66]

	*Approved **		*Proposed*	
($ in millions)	**2020**	**2021**	**2022**	**2023**
O&M Adjustments	36.1	33.3	37.4	39.9
Capital Adjustments	167.0	90.3	91.8	91.5
Revenue Requirement Adjustments	203.1	123.6	129.2	131.4

* 2020 and 2021 figures adjusted for cost of capital and uncollectible rates per D.19-12-056 and D.19-09-051, respectively.

SoCalGas is proposing to continue the authorized PSEP PTY mechanism where a separate capital-related revenue requirement for 2022 and 2023 is calculated based on forecasted capital additions. As explained in Ms. Ng's Declaration, for 2022, SoCalGas is proposing to use the PSEP projects presented in the record of this proceeding as the basis for computing capital

[64] Attachment A (Hom) at ¶¶ 18-20.
[65] D.19-09-051 at 705.
[66] Figures may not add due to rounding.

additions.[67] Ms. Ng also describes that SoCalGas is not proposing additional capital forecasts for 2023 in this Petition.[68] Rather, SoCalGas is requesting to calculate capital additions for 2023 on the PSEP projects already presented for 2022 (and approved in 2019-2021) in the evidentiary record of the instant proceeding.[69]

Specifically, to calculate the 2022 and 2023 revenue requirement associated with SoCalGas' Petition proposal, the following adjustments were made to the authorized PTY PSEP capital-related revenue requirement calculation:[70]

a. The logic in the 2019 GRC Decision's PSEP PTY workpapers were extended additional years in order to capture the 2022 and 2023 capital-related revenue requirement as proposed in this Petition.

b. The 2022 PSEP capital forecasts for projects with an in-service date of 2022 that were removed from the 2019 GRC Decision workpapers, were added back and modeled in the workpapers from Step 1 above. These 2022 PSEP capital forecasts were presented in SoCalGas' 2019 GRC Application.[71] When adding back these 2022 PSEP capital forecasts, SoCalGas applied the adjustments adopted by the Commission in the 2019 GRC Decision for PSEP project forecasts to the 2022 PSEP project capital forecasts originally presented in the 2019 GRC Application.[72]

c. No new capital project forecasts (i.e., capital expenditures) for 2023 were included.

d. Limited updates were applied, as described in Mr. Hom's declaration, including uncollectible rates, escalation factors, and authorized rate of return.

SoCalGas' PSEP capital-related revenue requirements, authorized for 2020 and 2021 and requested in this Petition for 2022 and 2023 are provided in Table 2 below:

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[67] Attachment D (Ng) at ¶ 13.
[68] *Id.* at ¶ 14.
[69] Attachment C (Aragon) at ¶ 16 (citing Attachment D (Ng)).
[70] *Id.* at ¶ 17.
[71] *See* Exhibit 231 (SoCalGas Philips Direct) at Section X.
[72] D.19-09-051, COL 44 at 766 ("The approved PSEP capital projects should be subject to a 10 percentage points reduction of the risk adjustment component."); *see also id.* at 215 ("The Line 44-1008 replacement project is not authorized …").

Table 2: SoCalGas Proposed PSEP Post-Test Years Attrition Adjustments

	Approved		*Proposed*	
($ in millions)	**2020**	**2021**	**2022**	**2023**
PSEP Capital Rev Req Adjustment *	12.7	25.2	25.9	5.5
Total PSEP Capital Expenditures	154.0	204.4	36.7	0.0

* Figures not adjusted for cost of capital and uncollectible rates.

Continuing a distinct PSEP capital-related revenue requirement is needed because, similar to the approval in the 2019 GRC Decision, SoCalGas continues to forecast PSEP work that will close to plant in service in 2022 and 2023 that is not accounted for in the traditional post-test year mechanism. SoCalGas' PSEP proposal in this Petition is consistent with the record of this proceeding and the 2019 GRC Decision, in that it is forecasting capital additions as the basis for the PTY revenue requirement.

Table 3 below presents a summary of SoCalGas' total post-test year revenue requirement proposals for 2022 and 2023. These proposals include: (1) an O&M adjustment; (2) a capital-related adjustment (without PSEP); (3) a PSEP capital-related adjustment; and (4) reflects the updates for uncollectibles rates, escalation factors, and rate of return. SoCalGas' total proposed attrition-year revenue increases are $155.1 million (4.95 percent) in 2022 and $136.8 million (4.16 percent) in 2023. Workpapers detailing the post-test year mechanism are attached to Mr. Aragon's declaration as Attachments C.1 and C.2.

Table 3: Summary of SoCalGas Proposed Post-Test Year Attrition[73]

	Approved		*Proposed*	
($ in millions)	**2020**	**2021**	**2022**	**2023**
O&M Adjustments	36.1	33.3	37.4	39.9
Capital Adjustments	167.0	90.3	91.8	91.5
Revenue Requirement Adjustments	203.1	123.6	129.2	131.4
PSEP Capital Adjustments	12.7	25.2	25.9	5.5
Revenue Requirement Adjustments *	215.8	148.9	155.1	136.8

* 2020 and 2021 figures adjusted for cost of capital and uncollectible rates per D.19-12-056 and D.19-09-051, respectively.

[73] Figures may not add due to rounding.

2. SDG&E's Proposed Revenue Requirements for 2022 and 2023 Are Derived Using the Authorized Post-Test Year Ratemaking Mechanism.

SDG&E proposes to extend the post-test year mechanism adopted in the 2019 GRC Decision to attrition years 2022 and 2023. Consistent with the approved PTY mechanism, SDG&E's proposed attrition year 2022 and 2023 increases for capital investments are based on an escalated (using Commission-approved Global Insight indices) seven-year average of capital additions authorized in the 2019 GRC Decision, with updates as described in Mr. Hom's declaration.[74] O&M expenses (including medical) will also continue to be escalated using the Global Insight index approved in the 2019 GRC Decision, as updated.

Applying the same post-test year methodology adopted in the 2019 GRC Decision, as explained in Mr. Deremer's declaration,[75] and making the limited updates described in Mr. Hom's declaration[76] yields attrition-year revenue increases of $106.2 million (4.77 percent) in 2022 and $108.1 million (4.64 percent) in 2023, as shown in Table 4 below. Workpapers detailing the post-test year mechanism are attached, as Attachment B.1.

Table 4: SDG&E Proposed Post-Test Years Attrition Adjustments[77]

	*Approved**		*Proposed*	
($ in millions)	**2020**	**2021**	**2022**	**2023**
O&M Adjustments	20.1	19.2	21.1	22.2
Capital Adjustments	114.1	83.2	85.1	85.9
Revenue Requirement Adjustments	134.1	102.4	106.2	108.1

*2020 and 2021 figures adjusted for uncollectible rates per ordering paragraph 18 in D.19-09-051.

74 Attachment A (Hom) at ¶¶ 18-20.
75 Attachment B (Deremer) at ¶¶ 5-8.
76 Attachment A (Hom) at ¶¶ 18-20.
77 Figures may not add due to rounding.

C. Extending Use of the Currently Authorized Post-Test Year Mechanism into 2022 and 2023 Is Reasonable.

Continuing the use of the adopted attrition methodology in the 2019 GRC Decision is reasonable, as it is the result of an extensive review of the record evidence in this proceeding, including various proposals presented by different parties,[78] and has been thoroughly examined and litigated as part of the GRC process.

SoCalGas' and SDG&E's testimony in the underlying proceeding also supports a conclusion that extending the PTY mechanism to 2022 and 2023 is reasonable. SoCalGas' and SDG&E's PTY witnesses testified to their evolving capital programs, with a greater focus on increasing investment in utility safety, reliability, grid modernization and clean energy, which directly support California's energy policies.[79] The PTY witnesses testified to Petitioners' S-MAP and RAMP focus, and that through these proceedings, SoCalGas and SDG&E would continue to identify necessary investment opportunities in safety and reliability through the new risk management tools and processes in upcoming years.[80] SoCalGas' and SDG&E's risk management and policy witness also testified to Petitioners' detailed commitment through 2025 and beyond on how they will "continue to build on the progress made thus far to develop their risk, asset, and investment management programs and the overall integration of the three"[81] and on "working with stakeholders during this GRC cycle, and beyond, to meet Commission directives."[82] The Commission's adopted PTY mechanism for capital-related costs captures the

[78] D.19-09-051 at 705-706.
[79] Ex. 242 (SoCalGas Malik 2nd Revised Direct) at JAM-8; Ex. 245 (SDG&E Deremer 2nd Revised Direct) at KJD-7.
[80] Ex. 242 (SoCalGas Malik 2nd Revised Direct) at JAM-8; Ex. 245 (SDG&E Deremer 2nd Revised Direct) at KJD-7
[81] Ex. 3 (SoCalGas/SDG&E Day Revised Direct) at DD-24.
[82] *Id.* at DD-25.

recent S-MAP and RAMP focus and historical increase in capital additions and reflects SoCalGas' and SDG&E's evolving priorities in these areas.[83]

Continuing the authorized post-test year mechanism through 2022 and 2023 is thus beneficial for the same reasons the Commission provided in authorizing it for 2020 and 2021, as found in the 2019 GRC Decision, because it "reasonably reflects … historical adjustments as well as current and forward-looking [capital] additions,"[84] "provides a more effective normalization of capital additions,"[85] while at the same time maintains SoCalGas' and SDG&E's "forward-looking focus and increased programs on improving safety, risk mitigation, grid modernization, and support of California's clean energy and environmental initiatives."[86] These safety and risk mitigation improvements include the activities associated with the 2016 and 2019 RAMP Reports, which aim to mitigate SoCalGas and SDG&E's top safety risks.

Further, the method of calculating the revenue requirement for PSEP in this Petition is reasonable because it will enable SoCalGas to continue to implement PSEP to enhance the safety of California's gas transmission infrastructure, in accordance with Commission requirements and State law.[87] It also is supported by the evidence in the record of this proceeding (i.e., the detailed PSEP project forecasts for 2022 that were supported by testimony and supplemental workpapers).[88] The mechanism takes into account the inherent challenges of forecasting projects to be executed several years into the future, by extending the cost forecast without inhibiting SoCalGas' ability to sequence the construction in accordance with the Commission-approved

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[83] Attachment B (Deremer) at ¶ 10; Attachment C (Aragon) at ¶ 10.
[84] D.19-09-051 at 708.
[85] *Id.* at 709.
[86] *Id.* at 709.
[87] Attachment D (Ng) at ¶ 16.
[88] *Id.* at ¶ 17.

PSEP decision tree and prioritization process using updated assessments of pipeline conditions, permitting, land acquisition, and material lead times, as well as operational, environmental, community and customer impacts for each project.[89] Finally, the Commission and interested parties will have the opportunity to evaluate PSEP project forecasts for those years during the TY 2024 GRC proceeding and preview the proposed PSEP level of work in the 2021 RAMP submittal.[90] PSEP will also be included in the annual Risk Spending Accountability Reporting,[91] which will align PSEP project forecasts with the rate case plan requirements for other GRC forecasted projects.

D. Updating Individual Cost Forecasts Would Be Unworkable.

As described above, SoCalGas and SDG&E have applied the ratemaking principles stated in the RCP Decision to "update[] … all relevant forecasts from their 2019 GRC applications" for 2022 and 2023, as the RCP Decision requires,[92] through use of their authorized post-test year ratemaking mechanisms. Because the 2019 GRC Decision has already reached final determinations on the direct dollar forecast requests and post-test year revenue requirements for 2020 and 2021 in the underlying proceeding, consistent with the RCP Decision's described methodology for calculating attrition year increases, further updates to individual cost forecasts are unnecessary.[93] If ordered to make comprehensive forecast updates in this Petition, all O&M and direct capital cost witnesses would need to submit additional testimony, as would the other non-cost witnesses that support the calculation of the revenue requirement (e.g., Rate Base, Taxes, Depreciation, Working Cash).[94] This would be the equivalent of putting together a

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[89] *Id.* at ¶ 18.
[90] *Id.* at ¶ 19.
[91] *See* D.19-04-020, OP 8, 9 at 64-65.
[92] D.20-01-002 at 53.
[93] Attachment A (Hom) at ¶ 23.
[94] *Id.* at ¶ 23.

substantial forecasted GRC showing within months of having received the final TY 2019 GRC Decision.

Proposing a cumbersome forecasting methodology for attrition years 2022 and 2023, such as conducting an new GRC showing, would also be inconsistent with the RCP Decision's stated efficiency goals – to "allow the utilities and stakeholders to dedicate…less time litigating GRC applications"[95] and for "GRC proceedings [to] follow a predictable schedule that balances the need for timely Commission decisions with procedural fairness for all parties."[96] It also conflicts with the RCP Decision's directive to file a petition for modification of the 2019 GRC Decision (and not a new GRC application), "as soon as practicable."[97]

Further, complicated proposals in post-test year ratemaking have been previously rejected by the Commission. In determining an authorized mechanism, the 2019 GRC Decision found that selectively updating certain items while leaving other items as forecast "would be overly complicated."[98] Similarly, the Commission has consistently favored a simpler escalation-based approach over a capital budget-based approach to PTY ratemaking.[99] For example, the final decision in Southern California Edison's ("SCE's") TY 2018 proceeding rejected SCE's budget-based capital addition forecast proposal for capital-related attrition, noting that the Commission also rejected similar approaches in SCE's GRCs for TY 2006, TY 2012 and TY 2015.[100]

2022 and 2023 direct cost forecasts are not included in the post-test year ratemaking model, due to the design of the Commission-adopted mechanism. Instead, through the

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[95] D.20-01-002 at 33.
[96] *Id.* at 2.
[97] D.20-01-002 at 55.
[98] D.19-09-051 at 709.
[99] *See, e.g.,* D.12-11-051 at 606 (quoting D.09-03-025) ("[T]here is a fundamental problem with budget-based ratemaking that boils down to the fact that budgets are not always implemented as planned.").
[100] D.19-05-020 at 283.

Commission's authorized mechanism for post-test years 2020 and 2021, the entire O&M margin is escalated using a weighted labor/non-labor escalation factor, as discussed in Mr. Hom's declaration.[101] Additionally, the PTY capital-related revenue requirement is calculated using a methodology based on a seven-year capital additions average. The Commission found that this seven-year average "…reasonably reflects both historical adjustments as well as current and forward-looking additions in light of the evolving changes brought about by the utilities' focus on increasing investment in utility safety and reliability and investments aimed at mitigating safety risk and providing clean and reliable energy."[102] The seven-year average, which includes four recorded years and three forecasted years, is still appropriate to use in this Petition as the starting point of the post-test year calculation. Including additional recorded years would impact the revenue requirements for 2020 and 2021, which have already been authorized by the Commission.[103] In the underlying proceeding, the Commission also acknowledged "…that it would be overly complicated to update certain items for 2017 actuals while leaving other items as forecast and so it is reasonable to apply forecasted capital additions for 2017 to 2019 since certain 2017 information was not yet available when the application was prepared."[104] This same rationale applies to the mismatch in recorded and forecasted costs if the post-test year calculation were to be revised to include additional recorded years in the seven-year average of capital additions.[105]

Accordingly, making further updates to direct project cost forecasts for purposes of this Petition would be unworkable.[106] All relevant direct cost forecasts have been addressed and

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[101] Attachment A (Hom) at ¶ 26.
[102] D.19-09-051 at 708-709 (citation omitted).
[103] Attachment A (Hom) at ¶ 26.
[104] D.19-09-051 at 709.
[105] Attachment A (Hom) at ¶ 26.
[106] *Id.* at ¶ 27.

incorporated into the TY revenue requirement through the 2019 GRC Decision. These direct costs form the basis to calculate the post-test year increases for 2020 – 2023. Regarding the precision of applying an authorized post-test year methodology into future successive attrition year revenue requirements, the RCP Decision states:

> [T]he Commission's decision on the test year is based on its examination of detailed utility budgets for a year very close in the future, while the revenue requirement for each subsequent attrition year is often established using escalation factors that are bound to be less precise for each successive attrition year. This is the case even with our current three-year GRC cycle. We do not find that adding a third attrition year will fundamentally change how we approach this task in future GRCs.[107]

Moreover, the RCP Decision moves SoCalGas' and SDG&E's next test year to 2024. Consistent with previously presented GRC showings, SoCalGas and SDG&E will be providing capital project forecasts in its next GRC for the years 2022, 2023, and test year 2024 to determine the revenue requirement for TY 2024. The forecasts for 2022, 2023, and 2024 will include direct dollar forecasts for specific projects. The Commission and parties will have an opportunity to review new projects and forecasts for these years, which will also be subject to the full GRC evidentiary process. Accordingly, project forecasts associated with 2022, 2023, and 2024 are appropriately considered in the TY 2024 GRC, rather than this Petition.[108]

E. SoCalGas and SDG&E Request a Continuation of all Other Post-Test Year Determinations in the 2019 GRC Decision Through 2022 and 2023.

The 2019 GRC Decision also approved the continuation of SoCalGas' and SDG&E's previously authorized Z-Factor mechanisms,[109] among other determinations that would continue during the post-test years. For example, the 2019 GRC Decision issued various determinations related to regulatory accounts that would apply during 2019 and the post-test years (2020 and

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[107] D.20-01-002 at 37.
[108] Attachment A (Hom) at ¶ 28.
[109] D.19-09-051, OP 4 at 776.

2021). For example, the balancing accounts of the pipeline integrity management programs, the Transmission Integrity Management Program Balancing Account ("TIMPBA") and the Distribution Integrity Management Program Balancing Account ("DIMPBA"), are managed by SoCalGas and SDG&E over a GRC cycle and are subject to a mechanism where SoCalGas and SDG&E must file a Tier 3 advice letter for undercollections up to 35 percent and an application for undercollections above 35 percent of its authorized O&M and capital expenses. SoCalGas and SDG&E request that Z-Factor, regulatory accounting provisions, and any other post-test year determinations reflected in the 2019 GRC Decision (including regulatory accounting mechanisms, the measurements of them, and whether thresholds are met) would continue through 2022 and 2023 and be calculated over the GRC cycle, now through December 31, 2023.

IV. RAMP-RELATED INFORMATION SUPPORTS THE COMMISSION'S EVALUATION OF SOCALGAS AND SDG&E'S 2022 AND 2023 ATTRITION YEAR PROPOSALS AND AN EXPEDITIOUS PROCEDURAL DISPOSITION OF THEIR CONSOLIDATED RAMP PROCEEDING.

The RCP Decision requires that this PFM should include certain RAMP-related "information and procedural proposals," as follows:

> [The] petition for modification of D.19-09-051 should provide RAMP-related information and procedural proposals to (1) support the Commission's evaluation of their 2022 and 2023 attrition year proposals; (2) suggest a procedural disposition for I.19-11-010 and I.19-11-011; and (3) explain to the Commission and interested parties how the utilities intend to submit their RAMP applications in support of their test year 2024 GRCs.[110]

On March 23, 2020 and April 6, 2020, SoCalGas and SDG&E filed briefs in the 2019 RAMP Proceeding that provide a detailed description of the relationships between the Commission's S-MAP, RAMP, and GRC proceedings.[111] This section provides information,

[110] D.20-01-002 at 53.

[111] I.19-11-010/-011 (cons.), Opening Brief of SoCalGas and SDG&E (March 23, 2020) and Response Brief of SoCalGas and SDG&E (April 6, 2020) (the "March 23 and April 6 RAMP Briefs"), incorporated by reference herein.

including from the March 23 and April 6 briefs (incorporated by reference herein), which addresses each of the above three RCP Decision requirements in turn. Specifically: (1) the programs identified in SoCalGas' and SDG&E's 2016 RAMP Reports were part of the test year and post-test year requests authorized in the 2019 GRC Decision, and the Petition's 2022 and 2023 attrition year proposals will continue to support the programs and activities identified in both the 2016 and 2019 RAMP Reports; (2) an expeditious procedural disposition of the 2019 RAMP Proceeding is warranted, as described in SoCalGas and SDG&E's March 23 and April 6 RAMP briefs; and (3) SoCalGas' and SDG&E's next (May 15, 2021) RAMP Reports will provide RAMP forecast years 2022, 2023, and 2024, consistent with a TY 2024 GRC.

A. RAMP-Related Information from the 2016 and 2019 Reports Support the Commission's Evaluation of SoCalGas and SDG&E's 2022 and 2023 Attrition Year Proposals.

As described above in section II.A, the analysis resulting from the 2016 RAMP Reports and reporting process was integrated into SoCalGas' and SDG&E's TY 2019 GRC requests for risk mitigation funding, and the test year and post-test year revenue requirements authorized by the 2019 GRC Decision were thus shaped by the 2016 RAMP Reports. The 2016 RAMP process, and the models presented in the S-MAP, worked as intended and were constructive in identifying potential mitigants to further reduce risk to employees, contractors, and the public.[112] The decision closing I.16-10-015/-016 recognized the positive, valuable impacts of the 2016 RAMP Reports on SoCalGas and SDG&E's risk management procedures and TY 2019 testimony showing:

> Testimony included in the Test Year 2019 GRC applications contain sections pertaining to RAMP and an assessment of feedback from the RAMP process. Proposed spending for safety mitigation activities and the efficiency of risk mitigation funding are to be reviewed in the Test Year 2019 GRC applications. The RAMP process had positive impacts on SDG&E's and SoCalGas' risk

[112] *See* Ex. 3 (SoCalGas/SDG&E Day Revised Direct) at DD-18.

> management procedures. Key safety risks and proposed mitigation activities were more thoroughly reviewed, assessed, and analyzed. The RAMP process brings safety to the forefront so that potential mitigations and proposed spending to further reduce risk to the public, employees, and contractors can be more thoroughly reviewed in the GRC applications.[113]

Further, the 2019 GRC Decision explained that the Commission's continuing developments in S-MAP and RAMP are refining processes for risk mitigation analysis, accountability reporting, and measurements on an ongoing basis:

> The SMAP, RAMP, and spending accountability process to integrate risk mitigation activities into the GRC began in 2014 and is still being refined. In April 2019, the Commission adopted 26 safety metrics for which utilities are to report their progress toward the risk mitigation goals set out in the GRCs. In addition, the recently closed and future SMAP proceedings have evaluated and will continue to evaluate the minimum elements to be used by large utilities for risk mitigation analysis in future RAMP and GRC applications. The Commission also approved improvements to Risk Mitigation Accountability and the Risk Spending Accountability reports, which will require additional internal tracking processes and tools to measure how well identified risks are actually being mitigated, and the risk reduced per dollar spent.[114]

Many of the programs that SoCalGas and SDG&E recently forecasted in their 2019 RAMP Reports were part of SoCalGas' and SDG&E's test year revenue requirement request in the TY 2019 GRC, were authorized in the 2019 GRC Decision, and will be supported by the upcoming PFM's post-test year revenue requirement proposals. As the 2019 GRC Decision noted, "[i]n reviewing the RAMP-driven portions of witness testimony in this GRC, we find that many of the activities identified by Applicants as flowing from the RAMP and mitigating risk are activities that were already being performed by Applicants and were included in prior GRCs"[115] and concluded that "[m]any of these programs are being approved and the funding

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[113] D.18-04-016 at 1-2.
[114] D.19-09-051 at 21 (citations omitted).
[115] *Id.* at 21-22.

allows SDG&E and SoCalGas to perform increased mitigation efforts to mitigate key safety risks."[116]

As was the case with the 2016 RAMP Reports (which were integrated into the TY 2019 GRC testimony), many of the activities that were identified in the 2019 RAMP Reports as mitigating key safety risks are long-standing programs that continue to be performed today. The costs associated with control activities that are identified in the 2019 RAMP Reports were also part of the TY 2019 GRC requests, are part of the TY 2019 GRC Decision's authorized revenue requirements for the test year and post-test years, and are thus inherently included in the 2022 and 2023 attrition year requests, which will continue to support mitigating safety risks on an ongoing basis.

Moreover, although SoCalGas and SDG&E believe that the 2019 RAMP Proceeding is ripe to be closed, as stated in their March 23 and April 6 RAMP briefs, the information from the 2019 RAMP Reports continues to be publicly available and to provide useful information regarding Petitioners' key risks and their ongoing and planned programs to mitigate them. And although new mitigations presented for the first time in the 2019 RAMP Reports for the years 2020 through 2022 would not have been specifically included or adopted in the TY 2019 GRC final decision, GRC funding may be reprioritized in order to undertake incremental activities identified in the 2019 RAMP Reports.[117] As the Rate Case Plan Decision states: "The Commission has always acknowledged that utilities may need to reprioritize spending between GRCs. Now, given the evolving reality [of moving to a four-year GRC cycle], that necessity may even be growing."[118] Reprioritizing spending also allows utilities to "[r]espond to

[116] D.19-09-051 at 4.
[117] *See* D.20-01-002 at 38.
[118] *Id.* at 38.

immediate or short-term crises outside of the RAMP and GRC process,"[119] in accordance with Commission directive. The Commission has stated: "RAMP and GRCs…are not designed to addresses immediate needs; the utilities have responsibility for addressing safety regardless of the GRC cycle."[120]

Further, the RCP Decision concluded that a longer GRC cycle will provide ample accountability of utility spending through the new accountability reporting structures (which will include years 2022 and 2023) and supported less litigation time for GRCs:

> First, the longer cycle will allow the utilities and stakeholders to dedicate more time to implementing the new risk-mitigation and accountability structures that this Commission established earlier in this rulemaking, and less time litigating GRC applications. Second, the longer cycle will enable the Commission and staff to shift their focus to monitoring utility spending in something closer to real-time, especially when the utility decides to re-prioritize authorized funding for another purpose.[121]

The extra time that SoCalGas and SDG&E will have in the additional attrition years to implement risk mitigation and safety-related activities is a benefit of the RCP Decision, which emphasized the importance of "creat[ing] more time for the utilities to focus on day-to-day operations" and "implementing the new risk-mitigation and accountability structures" as "compelling reason[s]" for adopting four-year GRC cycles.[122]

Thus, the revenue requirement increases requested in this Petition will allow SoCalGas and SDG&E to continue to invest in risk mitigation and safety-related activities, which have been presented in the 2016 and/or 2019 RAMP Reports. Such spending would be described,

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[119] D.18-04-016 at 6 n.7 (citing D.16-08-018 at 152).
[120] *Id.* at 6 n.7 (citing D.16-08-018 at 152).
[121] D.20-01-002 at 32-33.
[122] *Id.* at 33.

reported, and subject to annual oversight through the accountability reporting framework adopted by the Commission.[123]

B. SoCalGas and SDG&E Have Requested an Expeditious Procedural Disposition in the 2019 RAMP Proceeding, Which Is Supported by a Majority of RAMP Parties.

SoCalGas' and SDG&E's 2019 RAMP Reports present a current assessment of key safety risks and the proposed activities for mitigating those risks, for purposes of integrating the results of the 2019 RAMP Reports into their respective TY 2022 GRC applications. But because the Commission has modified SoCalGas' and SDG&E's current GRC cycle, setting 2024 as their next GRC test year[124] and requiring their next RAMP Reports to be filed on May 15, 2021, the 2019 RAMP Reports will no longer inform Respondents' next GRC. Further, the RAMP proceeding will not result in a substantive decision on the merits.[125] Therefore, as described above and in the March 23 and April 6 RAMP briefs, SoCalGas and SDG&E have proposed an expeditious closure of the RAMP proceeding to meet the current purpose of this proceeding and to conserve parties' and Commission resources. The majority of RAMP parties have either supported or not taken issue with adopting one of the two alternatives SoCalGas and SDG&E proposed to close the RAMP proceeding.[126] Notably, TURN, a predominant party in risk-related proceedings before the Commission, also supports expeditious closure of the 2019 RAMP Proceedings.[127]

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[123] *See accountability reporting requirements set forth in* D.19-04-020 and D.14-12-025.
[124] D.20-01-002 at 3, 53.
[125] *See* D.18-04-016 at 5 ("As described in D.14-12-025, no decision is expected to be issued in these proceedings and this decision only serves to close out these RAMP OIIs."); *see also* D.19-10-007 at 6 (closing PG&E's RAMP proceeding without a decision on the merits).
[126] *See* I.19-11-010/-011 (cons.), SoCalGas and SDG&E's Joint PHC Statement's summary of parties' positions at 10-11; *see also* PHC Statements filed by Cal Advocates, TURN, UCAN, and Mussey Grade.
[127] I.19-11-010/-011 (cons.), Opening Brief of TURN Regarding Procedural Disposition of this Proceeding (March 23, 2020) at 3-4.

C. SoCalGas and SDG&E Will Submit Their Next RAMP Reports on May 15, 2021, Which Will Include RAMP Forecast Years 2022, 2023, and 2024, Consistent with a Test Year 2024 GRC.

The RCP Decision extended SoCalGas' and SDG&E's current GRC cycle from three to five years, moved their next GRC application filing dates to May 15, 2022 (using TY 2024), and modified the filing date of Respondents' next RAMP Reports to May 15, 2021.[128] As shown in Figure 1 below, SoCalGas' and SDG&E's 2021 RAMP Reports will forecast risk mitigations for the years 2022 through 2024 (consistent with the forecast years that will be presented in their TY 2024 GRC application), for an authorized revenue requirement that will apply in the years 2024 through 2027:

Figure 1

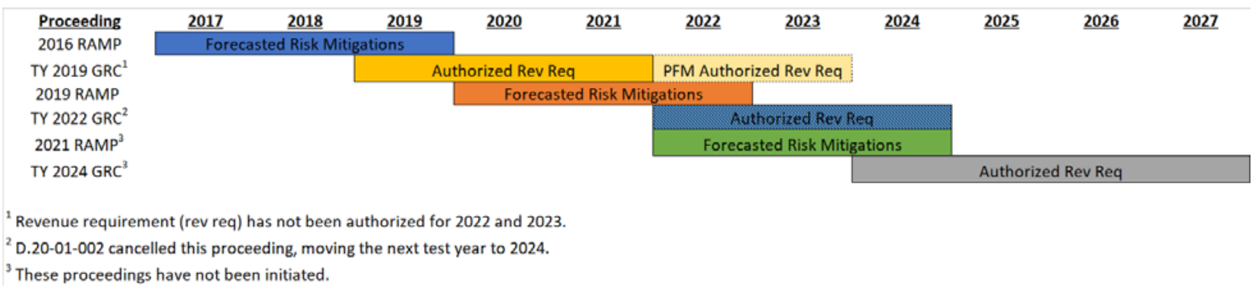

Figure 1 shows that RAMP submissions include forecasted risk mitigation programs for the years consistent with years that are forecasted in GRC proceedings, in order to integrate the submission into a future GRCs. For example, in SoCalGas' and SDG&E's 2016 RAMP Report, SoCalGas and SDG&E forecasted RAMP activities for years 2017 through 2019, which are the same years that were forecasted in the TY 2019 GRC. The 2016 RAMP Report did not, however, include RAMP forecasts for the post-test years requested in the GRC cycle, 2020 through 2022. This is also the case for SoCalGas' and SDG&E's recently submitted 2019 RAMP Reports, which forecasted risk mitigations from 2020 through 2022 (not 2023), for

[128] D.20-01-002 at 55.

inclusion in a future GRC, while the 2022 and 2023 attrition years will reflect the Commission's previously authorized 2019 GRC Decision and current GRC cycle.

V. PROPOSED SCHEDULE

SoCalGas and SDG&E have presented a simple methodology for extending application their currently authorized PTY ratemaking mechanism to the newly authorized attrition years 2022 and 2023, in Attachments A-D and supporting workpapers. The RCP Decision equally suggests a simple process for determining the 2022 and 2023 attrition years, by requiring SoCalGas and SDG&E to file a PFM – not a new GRC application – consistent with the 2019 GRC Decision "as soon as practicable."[129] Along these lines, SoCalGas and SDG&E propose that a simple, expedited schedule is adopted in this proceeding that is consistent with the RCP Decision's stated efficiency goals – to "allow the utilities and stakeholders to dedicate…less time litigating GRC applications"[130] and for "GRC proceedings [to] follow a predictable schedule that balances the need for timely Commission decisions with procedural fairness for all parties."[131] Consistent with the typical PFM process under the Commission's Rules of Practice and Procedure, SoCalGas and SDG&E believe that an evidentiary hearing is unnecessary for reaching a determination on this Petition. Further, any commenting party that requests an evidentiary hearing should be required to meet the burden of demonstrating that a true material issue of fact exists, such that a hearing is warranted. In any event, SoCalGas and SDG&E request a simplified proceeding schedule that will produce a final decision on attrition years 2022 and 2023 by no later than October 1, 2020.

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[129] *Id.* at 55.
[130] *Id.* at 33.
[131] *Id.* at 2.

VI. CONCLUSION

SoCalGas and SDG&E respectfully requests that the Commission modify the 2019 GRC Decision to adopt their proposed 2022 and 2023 attrition year increases (as described herein and in Attachments A-D), and the proposed revisions to the 2019 GRC Decision (as set forth in Attachment E), and any further relief as deemed necessary.

/s/ *Laura M. Earl*[132]
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Counsel for
SAN DIEGO GAS & ELECTRIC COMPANY

April 9, 2020

[132] Signed on behalf of Southern California Gas Company in accordance with Commission Rule 1.8(d).

ATTACHMENT A

RYAN HOM DECLARATION

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of San Diego Gas & Electric Company (U 902 M) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019.	Application No. 17-10-007 (Filed October 6, 2017)
And Related Matter.	Application No. 17-10-008 (Filed October 6, 2017)

DECLARATION OF RYAN HOM ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY AND SAN DIEGO GAS & ELECTRIC COMPANY IN SUPPORT OF THE JOINT PETITION FOR MODIFICATION OF D.19-09-051

I, Ryan Hom, declare that:

1. I am currently employed by Southern California Gas Company ("SoCalGas") as a Manager for the General Rate Case ("GRC") Financial Analysis group. My current responsibilities include overseeing the Results of Operations ("RO") Model and authorized revenue requirement for SoCalGas and San Diego Gas & Electric Company ("SDG&E"). I sponsored testimony on behalf of SoCalGas and SDG&E in the above-captioned Test Year ("TY") 2019 GRC proceeding, supporting their respective "Summary of Earnings."[1]

2. I have reviewed the Petition for Modification ("Petition") of Decision ("D.") D.19-09-051, approved on September 26, 2019 (hereinafter referred to as the "2019 GRC Decision").

3. As described in the Petition, the Commission's recent decision in Rulemaking ("R.") 13-11-006 (the "Rate Case Plan" or "RCP" Rulemaking), D.20-01-002 (hereinafter referred to as the "RCP Decision"), extends the GRC cycle for each large California investor-

[1] Ex. 344 (SoCalGas/Hom), Ex. 345 (SoCalGas/Hom), Ex. 346 (SDG&E/Hom), Ex. 347 (SDG&E/Hom), Ex. 358 (SoCalGas/Hom), Ex. 359 (SDG&E/Hom), Ex. 514 (SDG&E/SoCalGas/Hom).

owned utility ("IOU") from three to four years. To facilitate the transition from a three- to four-year GRC cycle for the IOUs, the RCP Decision "direct[s] SoCalGas and SDG&E to request two additional attrition years (2022 and 2023) in their petition for modification of D.19-09-051."[2]

4. Specifically, the RCP Decision requires SoCalGas and SDG&E to include in this Petition "detailed information to enable the Commission and interested parties to evaluate the utilities' requested revenue requirements for the two additional attrition years, including but not limited to: proposed escalation factors, anticipated Pipeline Safety Enhancement Plan and other capital projects for 2022 and 2023, and updates to all relevant forecasts from their 2019 GRC applications."[3] The RCP Decision also outlines required information for inclusion in this Petition related to the Risk Assessment Mitigation Phase ("RAMP").[4]

5. My declaration addresses the updates SoCalGas and SDG&E made in accordance with the RCP Decision and the 2019 GRC Decision to arrive at their respective revenue requirement requests for years 2022 and 2023. The post-test year ("PTY") ratemaking proposals are further addressed in the declarations of Kenneth J. Deremer for SDG&E (Attachment B) and Jesse Aragon for SoCalGas (Attachment C).

6. The revenue requirements SoCalGas and SDG&E propose for the additional attrition years 2022 and 2023 are based on the forecasts, RO model, and PTY mechanism authorized in the 2019 GRC Decision; as well as updated escalation factors from IHS Markit Global Insight ("Global Insight") (approved as reasonable for use in the 2019 GRC Decision),[5] uncollectible rates (updated by the mechanism authorized in the 2019 GRC Decision), and rates of return (authorized in the Cost of Capital proceeding); and are expected to continue to safely

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[2] D.20-01-002 at 52.
[3] *Id.* at 52-53.
[4] *Id.* at 53.
[5] *See* D.19-09-051, Findings of Fact ("FOF") 298 at 760 and 309 at 761.

provide utility service to customers, to maintain adequate system reliability, to provide responsive customer services, to comply with governmental regulations and orders, to recover costs for taxes and depreciation, and to recover revenue necessary to compensate investors for their capital investment in the utility.

SoCalGas' and SDG&E's Proposed Update Methodology Is Based on the 2019 GRC Decision's Authorized Revenue Requirements and Post-Test Year Mechanism.

7. As stated in the RCP Decision, "a GRC is a proceeding in which the Commission authorizes an investor-owned utility to recover through rates the reasonable capital investment costs and annual expenses necessary to operate and maintain its facilities and equipment in a safe and reliable manner."[6]

8. Generally, to develop GRC applications, SoCalGas and SDG&E use historical financial information to forecast costs (in direct dollars) as a means to calculate a test year revenue requirement. These historical and forecasted costs include various projects and activities, such as those associated with the RAMP. As the RCP Decision explained:

> The GRC application provides detailed forecasts of the applicant's capital investment expenses and its operating and maintenance (O&M) expenses for a designated 'test year' as well as forecasts for two subsequent post-test years, or 'attrition years.' The Commission's decision is based on its extensive review of the test year forecasts.[7]

9. The forecasts and revenue requirements authorized in the 2019 GRC Decision are the result of a comprehensively litigated GRC proceeding, which examined each individual forecast request sponsored by witnesses for numerous subject matter areas for both utilities. The robust forecasting GRC process is ultimately reflected in the 2019 test year revenue requirement, which forms the basis for determining the 2020 and 2021 post-test year revenue requirements,

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[6] D.20-01-002 at 8.
[7] *Id.* at 8 (citation omitted).

through application of the authorized post-test year mechanism.

10. As described in the declarations of Messrs. Deremer and Aragon (Attachments B and C, respectively), to provide the information required by the RCP Decision, SoCalGas and SDG&E began with the results authorized in the 2019 GRC Decision. SoCalGas and SDG&E then applied the authorized post-test-year mechanism and the limited updates described herein to derive revenue requirements for 2022 and 2023, as described below.

To Perform the RCP Decision's Required Updates, SoCalGas and SDG&E Updated the 2019 GRC Decision's Authorized Results.

11. The appropriate methodology for updating revenue requirement results for attrition years is described in the RCP Decision as follows: "The post-test year revenue requirements are typically determined by (1) escalating the test year O&M expenses, and (2) authorizing capital expenditures at a level determined by either (i) applying additional escalation factors, or (ii) further review of the applicant utility's actual capital budgets for those years."[8]

12. Here, the 2019 GRC Decision authorized a post-test year ratemaking mechanism that does not use specific, direct cost PTY capital project forecasts to calculate the post-test years' revenue requirements (with the exception of PSEP projects), as explained in more detail in the declarations of Messrs. Deremer and Aragon (Attachments B and C).

13. Consistent with the RCP Decision's described methodology, SoCalGas and SDG&E derived revenue requirement results for 2022 and 2023 by "escalating the test year O&M expenses" and "applying additional escalation factors,"[9] through the application of their authorized post-test year mechanism.

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[8] *Id.* at 8.
[9] *Id.* at 8.

14. SoCalGas and SDG&E also updated the following items for 2022 and 2023, consistent with items identified as appropriate for updating in the Commission's Rate Case Plan:

- Uncollectible rate;
- Cost escalation factors; and
- Authorized rate of return.[10]

A discussion of each of the updated items is further described below. The total revenue requirement change from these limited updates is provided in the Declarations of Messrs. Deremer and Aragon (Attachments B and C). For discussion of the specific PSEP proposals and the PSEP-related revenue requirement calculations, please refer to the declarations of Mr. Aragon and Deana Ng (Attachments C and D), respectively.

Uncollectible Rates Have Been Updated in Accordance with the 2019 GRC Decision.

15. SoCalGas and SDG&E propose to update uncollectible rates for 2022 and 2023, consistent with Ordering Paragraph ("OP") 18 in D.19-09-051. To do so, SoCalGas and SDG&E updated the 10-year rolling average to include actuals when appropriate.[11] 2022 and 2023 use the last recorded year (2019)[12] as a proxy for calculating the uncollectible rate.

16. Differences in the uncollectible rates are provided in the table below.

SDG&E	**2019 GRC Authorized**		**PFM Proposal**		**Difference**	
Uncollectible Rate	2022	2023	2022	2023	2022	2023
Electric/Gas	0.1740%	0.1740%	0.1650%	0.1650%	-0.009%	-0.009%

SoCalGas	**2019 GRC Authorized**		**PFM Proposal**		**Difference**	
Uncollectible Rate	2022	2023	2022	2023	2022	2023
Gas	0.3130%	0.3130%	0.2780%	0.2780%	-0.035%	-0.035%

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[10] *See* D.07-07-004, Appendix A at A-36, Items 1A and 1B.
[11] D.19-09-051 at 349-350.
[12] Uncollectible rates approved in D.19-09-051 were implemented in SoCalGas Advice Letter ("AL") 5536-G, approved January 23, 2020 and effective January 1, 2020 and SDG&E's AL 3449-E/2811-G, approved December 17, 2019 and effective January 1, 2020.

17. The uncollectible rate is typically revised annually.[13] Updates to the rate as calculated in this Petition are needed to reflect the most up-to-date assumptions. Consistent with the uncollectible practices adopted in the 2019 GRC Decision, SoCalGas and SDG&E will update the proxy calculated herein "by filing respective annual Tier 1 Advice Letters to the Commission's Energy Division."[14]

Updated Cost Escalation Factors Have Been Applied with Updates, Consistent with the 2019 GRC Decision and the RCP Decision.

18. SoCalGas and SDG&E have also updated escalation factors for 2022 and 2023, consistent with the methodology adopted in the 2019 GRC Decision. Based on the 2019 GRC Decision finding that "it [is] reasonable to apply different PTY mechanisms for O&M and for capital additions,"[15] these escalation factors are used in PTY ratemaking to annually adjust O&M (labor and non-labor) as well as capital additions.

19. The updated escalation factors are from Global Insight's fourth Quarter update (February 2020). The table below provides updated escalation rates.

SDG&E	**2019 GRC Authorized[1]**		**PFM Proposal[2]**		**Difference**	
Capital Escalation %	2022	2023	2022	2023	2022	2023
Electric	2.93%	2.84%	2.62%	2.72%	-0.31%	-0.12%
Generation	2.05%	2.19%	1.71%	1.96%	-0.34%	-0.23%
Gas	1.73%	2.62%	1.21%	2.38%	-0.52%	-0.24%
O&M Escalation %	2022	2023	2022	2023	2022	2023
Labor/Non-Labor	2.41%	2.48%	2.65%	2.71%	0.24%	0.23%
SoCalGas	**2019 GRC Authorized[1]**		**PFM Proposal[2]**		**Difference**	
Capital Escalation %	2022	2023	2022	2023	2022	2023
Gas	1.73%	2.62%	1.21%	2.38%	-0.52%	-0.24%
O&M Escalation %	2022	2023	2022	2023	2022	2023
Labor/Non-Labor	2.38%	2.45%	2.65%	2.71%	0.27%	0.26%

1 Source: August 2018 Update Filing (IHS Global Insight 2nd Quarter 2018 utility cost forecast)
2 Source: IHS Global Insight 4th Quarter 2019 utility cost forecast

13 *See* D.19-09-051, OP 18 at 780.
14 *Id.*
15 *Id.* at 707.

20. As the 2019 GRC Decision states, Global Insight-based cost escalation indices "have been relied on in past GRCs,"[16] were "not opposed by any intervenors,"[17]and "are reasonable."[18]

Rate of Return Assumptions Have Been Updated to Reflect the Recent Cost of Capital Decision.

21. On December 19, 2019, the Commission approved a TY 2020 Cost of Capital decision, D.19-12-056 ("2020 Cost of Capital Decision"). Among other things, the 2020 Cost of Capital Decision updated the rate of return for SoCalGas and SDG&E. For SoCalGas, the rate of return decreased from 7.34 percent to 7.30 percent.[19] For SDG&E, the rate of return remained the same as previously authorized, 7.55 percent.[20]

22. The decrease in SoCalGas' rate of return is reflected in this Petition. It is also shown in the table below.

SoCalGas	**2019 GRC Authorized**		**PFM Proposal**		**Difference**	
Rate of Return (ROR)	2022	2023	2022	2023	2022	2023
Gas	7.3445%	7.3445%	7.2989%	7.2989%	-0.0456%	-0.0456%

Updating Project Cost Forecasts Is Not Compatible with The PTY Mechanism Adopted in the 2019 GRC Final Decision.

23. Because 2019 GRC Decision has already reached final determinations on the direct dollar forecast requests and post-test year revenue requirements for 2020 and 2021 in the underlying proceeding, as well as the RCP Decision's described methodology for calculating attrition year increases, further updates are not necessary. If ordered to make comprehensive forecast updates in this Petition, all O&M and direct capital cost witnesses would need to submit

[16] *Id.* at 671.
[17] *Id.*, FOF 307 at 761.
[18] *Id.*, FOF 298 at 760 and 309 at 761.
[19] D.19-12-056, OP 5 at 55.
[20] *Id.*, OP 3 at 55. *See also* SDG&E's AL 3499-E/2836-G, approved on March 27, 2020 and effective on March 24, 2020.

additional testimony, as would the other non-cost witnesses that support the calculation of the revenue requirement (e.g., Rate Base, Taxes, Depreciation, Working Cash). This would be the equivalent of putting together a substantial interim forecasted GRC showing within months of having received the final TY 2019 GRC Commission decision.

24. Proposing a cumbersome forecasting methodology for attrition years 2022 and 2023, such as conducting an interim GRC showing, would be inconsistent with the RCP Decision's stated efficiency goals – to "allow the utilities and stakeholders to dedicate…less time litigating GRC applications"[21] and for "GRC proceedings [to] follow a predictable schedule that balances the need for timely Commission decisions with procedural fairness for all parties."[22] It also conflicts with the Commission's directive to file a petition for modification of the 2019 GRC Decision, "as soon as practicable."[23]

25. Further, complicated proposals in post-test year ratemaking have been previously rejected by the Commission. In determining an authorized mechanism, the 2019 GRC Decision found that selectively updating certain items while leaving other items as forecast "would be overly complicated."[24] Similarly, the Commission has consistently favored a simpler escalation-based approach over a capital budget-based approach to PTY ratemaking.[25] For example, the final decision in Southern California Edison's ("SCE's") TY 2018 proceeding rejected SCE's budget-based capital addition forecast proposal for capital-related attrition, noting that the Commission also rejected similar approaches in SCE's GRCs for TY 2006, TY 2012 and TY

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[21] D.20-01-002 at 33.
[22] *Id.* at 2.
[23] *Id.* at 55.
[24] D.19-09-051 at 709.
[25] *See, e.g.*, D.12-11-051 at 606 (quoting D.09-03-025) ("[T]here is a fundamental problem with budget-based ratemaking that boils down to the fact that budgets are not always implemented as planned.").

2015.[26]

26. 2022 and 2023 direct cost forecasts are not included in the post-test year ratemaking model, due to the design of the adopted mechanism. Instead, through the Commission's authorized mechanism for post-test years 2020 and 2021, the entire O&M margin is escalated using a weighted labor/non-labor escalation factor, as discussed above. Additionally, the PTY capital-related revenue requirement is calculated using a methodology based on a seven-year capital additions average. The Commission found that this seven-year average "…reasonably reflects both historical adjustments as well as current and forward-looking additions in light of the evolving changes brought about by the utilities' focus on increasing investment in utility safety and reliability and investments aimed at mitigating safety risk and providing clean and reliable energy."[27] The seven-year average, which includes four recorded years and three forecasted years, is still appropriate to use in this Petition as the starting point of the post-test year calculation. Including additional recorded years would impact the revenue requirements for 2020 and 2021, which was already authorized by the Commission. The Commission also acknowledged, "…that it would be overly complicated to update certain items for 2017 actuals while leaving other items as forecast and so it is reasonable to apply forecasted capital additions for 2017 to 2019 since certain 2017 information was not yet available when the application was prepared."[28] This same rationale applies to the mismatch in recorded and forecasted costs when revising the post-test year calculation to include additional recorded years in the seven-year average of capital additions.

[26] D.19-05-020 at 283.
[27] D.19-09-051 at 708-709 (citation omitted).
[28] *Id.* at 709.

27. Accordingly, making further updates to direct project cost forecasts would be inappropriate. All relevant direct cost forecasts have been addressed and incorporated into the TY revenue requirement through the 2019 GRC Decision. These direct costs form the basis to calculate the post-test year increases for 2020 – 2023.

28. Moreover, the RCP Decision moves SoCalGas' and SDG&E's next test year to 2024. Consistent with previously presented GRC showings, SoCalGas and SDG&E will be providing capital project forecasts in its next GRC for the years 2022, 2023, and test year 2024 to determine the revenue requirement for TY 2024. The forecasts for 2022, 2023, and 2024 will include direct dollar forecasts for specific projects. The Commission and parties will have an opportunity to review new projects and forecasts for these years, which will also be subject to the full GRC evidentiary process. Accordingly, project forecasts associated with 2022, 2023, and 2024 are appropriately suited for the TY 2024 GRC, rather than this Petition.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, except as to those matters stated to be on information and belief, and as to those matters, I believe them to be true and correct.

Executed this 9th day of April 2020, at Los Angeles, California.

/s/ Ryan Hom
Ryan Hom

ATTACHMENT B

KENNETH J. DEREMER DECLARATION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U 902 M) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019.	Application No. 17-10-007 (Filed October 6, 2017)
And Related Matter.	Application No. 17-10-008 (Filed October 6, 2017)

DECLARATION OF KENNETH J. DEREMER ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY IN SUPPORT OF THE JOINT PETITION FOR MODIFICATION OF D.19-09-051

I, Kenneth J. Deremer, declare that:

1. I am currently employed by San Diego Gas & Electric Company ("SDG&E") as the Director of Asset Management. My current responsibilities include the development, implementation and oversight of SDG&E's asset management policies, procedures, and plans.

2. I have reviewed the Petition for Modification ("Petition") of Decision ("D.") D.19-09-051, the Decision Addressing the Test Year ("TY") 2019 General Rate Cases ("GRCs") of SDG&E and Southern California Gas Company ("SoCalGas"), approved on September 26, 2019 (hereinafter referred to as the "2019 GRC Decision"). The purpose of my declaration is to provide the factual support for SDG&E's proposal for two additional attrition years, 2022 and 2023.

3. As described in the Petition, the Commission's recent decision in Rulemaking ("R.") 13-11-006 (the "Rate Case Plan" or "RCP" Rulemaking), D.20-01-002 (hereinafter referred to as the "RCP Decision"), extends the GRC cycle for each large California investor-owned utility ("IOU") from three to four years. The Petition implements requirements of the

RCP Decision by proposing just and reasonable interim 2022 and 2023 attrition year increases for SoCalGas and SDG&E, consistent with the RCP Decision's transition schedule to a four-year cycle for all IOUs. Specifically, the Petition asks the Commission to continue SDG&E's approved post-test year ("PTY") mechanism into 2022 and 2023.

The 2019 GRC Decision Approved a Post-Test Year Mechanism for 2020 and 2021.

4. The RCP Decision describes the general methodology for updating revenue requirement results for attrition years as follows: "The post-test year revenue requirements are typically determined by (1) escalating the test year O&M expenses, and (2) authorizing capital expenditures at a level determined by either (i) applying additional escalation factors, or (ii) further review of the applicant utility's actual capital budgets for those years."[1]

5. Here, for SoCalGas' and SDG&E's authorized PTY mechanism, the 2019 GRC Decision approved a two-part attrition mechanism for post-test years 2020 and 2021, where capital-related revenues and Operations and Maintenance ("O&M") expenses are separately escalated.[2] The Commission authorized the post-test year mechanism as part of an extensive review of the record evidence in this proceeding, including various proposals presented by different parties.[3] The authorized attrition mechanism is based on the following:

- **Capital Adjustment:** seven-year average of recorded and forecasted capital additions (2013-2019) that are escalated using IHS Markit Global Insight ("Global Insight") indices to 2019 dollars and then averaged; 2020 and 2021 are determined by escalating the seven-year average using the Global Insight indices.[4]
- **O&M Adjustment:** labor and non-labor (including medical) O&M are escalated using Global Insight indices.[5]

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[1] D.20-01-002 at 8.
[2] D.19-09-051 at 705.
[3] *Id.* at 705-706.
[4] *Id.* at 708-710.
[5] *Id.* at 708.

6. SDG&E's authorized PTY mechanism is based on an escalated seven-year average of recorded and forecasted capital additions, not on a continued review of actual capital costs. The 2019 GRC Decision also approved the continuation of SDG&E's previously authorized Z-Factor mechanisms.[6]

The Evidentiary Record in the Above-Captioned Proceeding Supports Continuing the Post-Test Year Mechanism for 2022 & 2023.

7. The Petition proposes to extend the post-test year mechanism adopted in the 2019 GRC Decision to attrition years 2022 and 2023. Consistent with the approved PTY mechanism, SDG&E's proposed attrition year 2022 and 2023 increases for capital investments are based on an escalated (using Commission-approved Global Insight indices) seven-year average of capital additions authorized in the 2019 GRC Decision. O&M expenses (including medical) will also continue to be escalated using the Global Insight index, as approved in the 2019 GRC Decision. SDG&E also performed updates for 2022 and 2023, as outlined in the declaration of Ryan Hom (Petition Attachment A). These updates are included in SDG&E's proposal to continue the post-test year mechanism.

8. Applying the same post-test year methodology adopted in the 2019 GRC Decision, as explained above, and making limited updates to approved escalation factors yields attrition-year revenue increases of $106.2 million (4.77 percent) in 2022 and $108.1 million (4.64 percent) in 2023, as shown in Table 1 below. Workpapers detailing the post-test year mechanism are attached to this declaration, as Attachment B.1.

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[6] *Id.,* Ordering Paragraph 4 at 776.

Table 1: SDG&E Proposed Post-Test Years Attrition Adjustments[7]

	*Approved**		*Proposed*	
($ in millions)	**2020**	**2021**	**2022**	**2023**
O&M Adjustments	20.1	19.2	21.1	22.2
Capital Adjustments	114.1	83.2	85.1	85.9
Revenue Requirement Adjustments	134.1	102.4	106.2	108.1

*2020 and 2021 figures adjusted for uncollectible rates per ordering paragraph 18 in D.19-09-051.

9. The adopted attrition methodology in the 2019 GRC Decision is appropriate for this Petition, as it has been thoroughly examined and litigated as part of the GRC process. Extending the PTY mechanism to 2022 and 2023 is reasonable, including for the many reasons outlined in SDG&E's testimony in this proceeding.[8]

10. SoCalGas' and SDG&E's PTY witnesses testified to their evolving capital programs, with a greater focus on increasing investment in utility safety, reliability, grid modernization and clean energy, which directly support California's energy policies.[9] The PTY witnesses testified to Petitioners' S-MAP and RAMP focus, and that through these proceedings, SoCalGas and SDG&E would continue to identify necessary investment opportunities in safety and reliability through the new risk management tools and processes in upcoming years.[10] SoCalGas' and SDG&E's risk management and policy witness also testified to Petitioners' detailed commitment through 2025 and beyond on how they will "continue to build on the progress made thus far to develop their risk, asset, and investment management programs and the overall integration of the three"[11] and on "working with stakeholders during this GRC cycle, and

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[7] Figures may not add due to rounding.
[8] *See* Ex. 245 (SDG&E Deremer 2nd Revised Direct) at KJD-1.
[9] Ex. 242 (SoCalGas Malik 2nd Revised Direct) at JAM-8; Ex. 245 (SDG&E Deremer 2nd Revised Direct) at KJD-7.
[10] *Id.*
[11] Ex. 3 (SoCalGas/SDG&E/Day) at DD-24.

beyond, to meet Commission directives."[12] The Commission's adopted PTY mechanism for capital-related costs captures the recent S-MAP and RAMP focus and historical increase in capital additions and reflects SoCalGas' and SDG&E's evolving priorities in these areas.

11. Continuing the authorized post-test year mechanism through 2022 and 2023 is thus beneficial for the same reasons the Commission provided in authorizing it for 2020 and 2021, because it "reasonably reflects … historical adjustments as well as current and forward-looking [capital] additions,"[13] "provides a more effective normalization of capital additions,"[14] and maintains SDG&E's "forward-looking focus and increased programs on improving safety, risk mitigation, grid modernization, and support of California's clean energy and environmental initiatives."[15]

12. I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, except as to those matters stated to be on information and belief, and as to those matters, I believe them to be true and correct.

Executed this 9th day of April 2020, at San Diego, California.

/s/ Kenneth J. Deremer
Kenneth J. Deremer

[12] *Id.* at DD-25.
[13] D.19-09-051 at 708.
[14] *Id.* at 709.
[15] *Id.*

ATTACHMENT B.1

SDG&E WORKPAPERS TO DECLARATION OF KENNETH J. DEREMER ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

TABLE OF CONTENTS

PETITION FOR MODIFICATION

This attachment provides detailed information, as required by Decision ("D.") 20-01-002, in support of SDG&E's attrition year requests for 2022 and 2023. This attachment also reflects the updates to uncollectible rates, escalation factors, and cost of capital as outlined in Ryan Hom's Declaration (Attachment A to the Petition for Modification).

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SDG&E

A. TOTAL REVENUE REQUIREMENT

SDG&E proposes extending the authorized post-test year ("PTY") ratemaking mechanism to update the 2019 test-year ("TY") authorized revenue requirement for two additional attrition years, 2022 and 2023. The adopted PTY ratemaking mechanism escalates revenue requirement in the PTYs 2020, 2021, 2022, and 2023, for:

1. Labor and non-labor operation and maintenance costs (including medical) based on IHS/Markit Global Insight's forecast (Section B), and
2. Capital investments based on an escalated 7-year average of capital additions (Section C).

The base margin amounts utilized throughout these workpapers to determine the revenue requirements in 2022 and 2023 were adopted in SDG&E's TY 2019 GRC Decision, D.19-09-051. SDG&E then reflected the TY 2020 Cost of Capital ("COC") decision, D.19-12-056,[1] and implemented the uncollectible rate pursuant to D.19-09-051.[2] Additionally, SDG&E added logic changes to incorporate the COC and uncollectible updates and updates for escalation factors. These changes are reflected in the PTY model for years 2020-2023.[3]

In preparing this workpaper, SDG&E applied the updates above to the PTYs 2020 through 2023 for modeling purposes only. SDG&E is not seeking to update the revenue requirements that were previously approved by the Commission in D.19-09-051.

Table 1 below summarizes the total revenue requirement associated with SDG&E's proposed PTY ratemaking mechanism including Miscellaneous Revenues and Franchise Fees & Uncollectible ("FF&U"). Detailed FF&U rate changes are included in Table 13 (Electric) and

[1] SDG&E's Advice Letter ("AL") 3499-E/2836-G, filed on January 21, 2020, effective on March 24, 2020.
[2] *See* SDG&E's AL 3449-E/2811-G, approved December 17, 2019 and effective January 1, 2020.
[3] This Petition does not reflect the post-test year revenue requirement adjustment required by Assembly Bill 1054. SDG&E filed AL 3488-E and 3488-E-A pursuant to Ordering Paragraph 6 of D.19-09-051 to separately address this adjustment.

Table 14 (Gas).

Table 1

Line No.	Description ($ in millions)	PTY – 2020	PTY – 2021	PTY – 2022	PTY – 2023
1	Total O&M Margin (excluding FFU)	754.4	773.0	793.5	815.0
2	Capital Related Costs (Depreciation, Taxes, Return)	1,285.7	1,368.9	1,454.0	1,540.0
3	Total (L1 + L2 + L3)	2,040.1	2,141.9	2,247.5	2,354.9
4	FF&U	66.6	67.3	68.0	68.7
5	Total Base Margin (L4 + L5)	2,106.7	2,209.2	2,315.5	2,423.6
6	Miscellaneous Revenues	17.5	17.5	17.5	17.5
7	Total Revenue Requirement (L6 + L7)	2,124.2	2,226.7	2,333.0	2,441.1
8	Cost of Capital Adjustment	-	-	-	-
9	FF&U Adjustment	(0.0)	(0.1)	(0.2)	(0.2)
10	Adjusted Total Revenue Requirement (L7 + L8 + L9)	2,124.2	2,226.6	2,332.7	2,440.9
11	Revenue Requirement Increase $	134.1	102.4	106.2	108.1
12	Revenue Requirement Increase %	*6.74%*	*4.82%*	*4.77%*	*4.64%*
	**Difference due to rounding.*				

B. OPERATION & MAINTENANCE ("O&M") EXPENSES

For modeling purposes, the starting base for O&M escalation is the authorized 2021 revenue requirement excluding miscellaneous revenues, capital related margin, and FF&U ("O&M Margin"). O&M expenses are determined in total for the electric distribution, electric generation and gas departments.

For simplicity in calculating PTY escalation of O&M, including medical, a gas and electric O&M utility input price index ("GEOMPI") is used to adjust O&M expenses to reflect the expected cost inflation of goods and services that SDG&E will incur to serve its customers. The calculation of GEOMPI is described in Mr. Scott Wilder's testimony (Exhibit 336) and is also shown in the Update Testimony of SoCalGas and SDG&E (Exhibit 514). The escalation rates for 2022 and 2023 are outlined in the Declaration of Ryan Hom. The PTY O&M revenue requirement prior to FF&U gross up is calculated below in Table 2 (differences due to rounding).

Table 2

Line No.	O&M Expense Adjustment ($ in millions)	TY-2019	2020	2021	2022	2023
1	Prior Year O&M Margin		$734.9	$754.4	$773.0	$793.5
2	O&M Escalation Rate		2.64%	2.47%	2.65%	2.71%
3	Attrition-year O&M Escalation (L1* L2)		$19.4	$18.6	$20.5	$21.5
4	O&M Expense (L1+ L3)	$734.9	$754.4	$773.0	$793.5	$815.0

C. CAPITAL-RELATED

This section describes the development of PTY plant additions and other PTY rate base changes to determine the capital-related revenue requirement (authorized returns, depreciation expense, taxes and gross ups) for the electric distribution ("ED"), electric generation ("EG") and gas distribution ("GD") departments. The recorded (2013-2016) plant additions are taken from historically recorded rate base. Forecasted (2017-2019) rate base components, plant additions and plant retirements are from the testimony and workpapers of SDG&E witness Mr. R. Craig Gentes (Exhibit 378 and 379). SDG&E escalates the average of 2013-2019 capital additions to determine PTY capital additions. Incremental depreciation and amortization reserve and deferred taxes are also calculated to determine the rate base for the attrition-year. The change in year-over-year rate base is used to calculate the capital cost components of the revenue requirement. The capital-related revenue requirement is shown in Table 3 below (differences due to rounding):

Table 3

Line No.	Capital-Related Attrition ($ in millions)	TY-2019	2020	2021	2022	2023
1	Prior Year Capital-Related Costs		$1,171.6	$1,285.7	$1,368.9	$1,454.0
2	Capital-Related Attrition		$114.1	$83.2	$85.1	$85.9
3	Capital-Related Costs (L1+ L2)	$1,171.6	$1,285.7	$1,368.9	$1,454.0	$1,540.0

The development of the PTY rate base and the derivation of individual revenue requirement components are described in detail below.

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SDG&E

1. Weighted Average ("WAVG") Rate Base (Tables 4, 6, 8): The starting point in developing WAVG rate base for each attrition-year is the prior year plant-in-service, accumulated depreciation reserve and accumulated amortization reserve. WAVG plant additions are added and capital retirements are subtracted to determine net plant additions. Changes to the net depreciation and net amortization reserve and accumulated deferred tax reserve are calculated as further described below.

   a) Weighted Net Plant Additions

      1) Plant additions (Table 5, 7, 9: Lines 10, 11-13) for the PTY are calculated using a seven-year average, four years of recorded (2013-2016) and three years of forecasted (2017-2019) capital additions. Each year is escalated to 2019 dollars and then averaged. The seven-year average is then escalated to 2020, 2021, 2022, and 2023 dollars using Global Insight indices, as described in the testimony of Scott Wilder (Exhibit 336) and Update Testimony of SoCalGas and SDG&E (Exhibit 514)._ The escalation rates for 2022 and 2023 are outlined in the Declaration of Ryan Hom (Attachment A in this Petition).

      2) Plant retirements (Table 5, 7, 9: Lines 10, 14-16) for the PTY are calculated using a seven-year average, four years of recorded (2013-2016) and three years of forecasted (2017-2019) capital retirements. Each year is escalated to 2019 dollars and then averaged. The seven-year average is then escalated to 2020, 2021, 2022, and 2023 dollars using Global Insight indices, as described in the testimony of Scott Wilder (Exhibit 336) and Update Testimony of SoCalGas and SDG&E (Exhibit 514). The escalation rates for 2022 and 2023 are outlined in the Declaration of Ryan Hom (Attachment A in this Petition).

      3) WAVG Net Plant Additions (Table 5, 7, 9: Lines 1-3, 17): Each PTY's WAVG net plant additions is calculated using the ratio of the prior year WAVG net plant additions balance to the prior year end of year ("EOY") net plant additions balance multiplied by the attrition-year's EOY net plant additions.

   b) Change in Accumulated Depreciation Reserve (Tables 5, 7, 9: Lines 4-6): Each PTY's WAVG net depreciation reserve is calculated using the ratio of the prior year WAVG net depreciation reserve to the prior year EOY net depreciation reserve multiplied by the attrition-year's EOY net depreciation reserve. Net depreciation reserve includes annual retirements, cost of removal and salvage.

   c) Change in Net Amortization Reserve (Tables 5, 7, 9: Lines 7-9): Each PTY's WAVG net amortization reserve is calculated using the ratio of the prior year WAVG net amortization reserve to the prior year EOY net amortization reserve multiplied by the attrition-year's EOY net amortization reserve.

d) Change in Accumulated Deferred Tax Reserve (Tables 4, 6: Line 12, Table 8: Line 13): Each PTY's WAVG accumulated deferred tax is calculated by multiplying the ratio of test year deferred taxes to the test year WAVG plant in service by the PTY's WAVG plant in service.

e) Accumulated Deferred Taxes - 2017 Tax Cuts & Jobs Act ("TCJA") Adj (Tables 4, 6: Line 9, Table 8: Line 10): SDG&E calculated the rate base adjustments using the average rate assumption method ("ARAM") as explained by witness Ragan Reeves (Exhibit 265) and continues the amortization of adjustment into the PTYs.

f) Working Capital and Other (Tables 4, 6: Lines 3, 4, 7, Table 8: Lines 3, 4, 5, 8): SDG&E is not proposing to change the rate base elements of Fuel in Storage, Materials and Supplies, Working Cash, and Customer Advances for Construction from the test year 2019 amounts.

g) Repair Deductions Rate Base Adjustment (Tables 4, 6: Line 6, Table 8: Line 7): SDG&E proposes to continue the amortization of this rate base adjustment as ordered in D.16-06-054, page 192, and adjusted for TCJA as discussed in the testimony and workpapers of witness Ragan Reeves (Exhibits 265 and 266).

h) Allocation of Electric General Plant and Common Plant (Tables 4, 6: Lines 15-16): To calculate the allocations of Electric General Plant and Common Plant from ED to EG for each PTY, SDG&E uses the ratio (from Table 4) of prior year allocated Electric General Plant to the plant-in-service multiplied by the attrition-year plant-in-service. Similarly, SDG&E uses the ratio (from Table 4) of prior year allocated Common Plant to the plant-in-service multiplied by the attrition-year plant-in-service. The resulting allocations are transferred to EG in Table 6.

The resulting WAVG Depreciated Rate Base and supporting calculations are shown in the tables below:

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SDG&E

Table 4

San Diego Gas and Electric Company
WEIGHTED AVERAGE DEPRECIATED RATE BASE
ELECTRIC DISTRIBUTION
(Thousands of Dollars)

		2019 RO Model				2020-2023 Attrition Year			
		Source: Witness: R. Craig Gentes / Exhibit 379							
		Recorded			Test	PTY	PTY	PTY	PTY
Line		Year	Estimated Year		Year	AY	AY	AY	AY
No.	Account Description	2016	2017	2018	2019	2020	2021	2022	2023
	Fixed Capital								
1	Plant In Service	6,979,749	7,451,447	8,048,918	8,801,459	9,567,996	10,194,453	10,839,524	11,501,744
2	Total Fixed Capital	6,979,749	7,451,447	8,048,918	8,801,459	9,567,996	10,194,453	10,839,524	11,501,744
	Working Capital								
3	Materials & Supplies	42,857	43,712	44,770	46,055	46,055	46,055	46,055	46,055
4	Working Cash	92,137	95,362	98,699	82,363	82,363	82,363	82,363	82,363
5	Total Working Capital	134,994	139,074	143,469	128,418	128,418	128,418	128,418	128,418
6	Repair Deductions Rate Base Adjustment (2016 - 2042)	(42,484)	(40,850)	(39,216)	(37,582)	(35,948)	(34,314)	(32,680)	(31,046)
7	Customer Advances For Construction	(34,041)	(35,366)	(33,343)	(40,749)	(40,749)	(40,749)	(40,749)	(40,749)
8	Total Other	(76,525)	(76,216)	(72,560)	(78,331)	(76,697)	(75,063)	(73,429)	(71,795)
	Deductions For Reserves								
9	Accumulated Deferred Taxes - 2017 Tax Cuts & Jobs Act Adj			223,713	212,958	202,203	191,448	180,693	169,939
10	Accumulated Depreciation Reserve	2,842,799	3,009,941	3,189,148	3,368,143	3,557,759	3,761,712	3,978,782	4,209,339
11	Accumulated Amortization Reserve	253,881	307,895	370,976	434,924	500,397	570,828	645,789	725,408
12	Accumulated Deferred Taxes	543,186	561,125	347,817	334,564	363,702	387,515	412,036	437,209
13	Total Deductions For Reserves	3,639,866	3,878,961	4,131,655	4,350,589	4,624,062	4,911,503	5,217,301	5,541,894
14	**Weighted Average Depreciated Rate Base**	3,398,352	3,635,344	3,988,173	4,500,957	4,995,655	5,336,305	5,677,213	6,016,473
15	Allocated Electric General		(11,887)	(11,852)	(13,098)	(14,238)	(15,171)	(16,131)	(17,116)
16	Allocated Common		(24,142)	(29,753)	(34,690)	(37,711)	(40,180)	(42,723)	(45,333)
17	**Total Rate Base**		**3,599,315**	**3,946,568**	**4,453,169**	**4,943,706**	**5,280,954**	**5,618,359**	**5,954,024**

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SDG&E

Table 5

San Diego Gas and Electric Company
WAVG Rate Base Support: Capital Additions, Capital Retirements, Net Depreciation and Amortization Reserve
ELECTRIC DISTRIBUTION
(Thousands of Dollars)

Line No.	Description	2019 RO Model		2020-2023 Attrition Year											
		2019		2020			2021			2022			2023		
		End of Year	WAVG	End of Year	WAVG	WAVG Increase	End of Year	WAVG	WAVG Increase	End of Year	WAVG	WAVG Increase	End of Year	WAVG	WAVG Increase
	Plant-in-Service														
1	Beginning of the Year	8,462,123	8,462,123	9,324,590	9,324,590	862,467	9,943,239	9,943,239	618,648	10,581,734	10,581,734	638,495	11,236,942	11,236,942	655,208
2	Net Plant Additions	862,467	339,336	618,648	243,406	(95,930)	638,495	251,215	7,809	655,208	257,790	6,576	673,031	264,802	7,012
3	Total	9,324,590	8,801,459	9,943,239	9,567,996	766,537	10,581,734	10,194,453	626,457	11,236,942	10,839,524	645,071	11,909,972	11,501,744	662,220
	Accumulated Depreciation Reserve														
4	Beginning of the Year	3,275,468	3,275,468	3,457,013	3,457,013	181,545	3,654,370	3,654,370	197,356	3,864,648	3,864,648	210,278	4,088,232	4,088,232	223,584
5	Net Depreciation Reserve	181,545	92,675	197,356	100,746	8,071	210,278	107,342	6,596	223,584	114,134	6,792	237,243	121,107	6,973
6	Total	3,457,013	3,368,143	3,654,370	3,557,759	189,616	3,864,648	3,761,712	203,953	4,088,232	3,978,782	217,070	4,325,475	4,209,339	230,557
	Accumulated Amortization Reserve														
7	Beginning of the Year	403,223	403,223	465,936	465,936	62,712	534,110	534,110	68,174	606,748	606,748	72,638	683,982	683,982	77,234
8	Net Amortization Reserve	62,712	31,701	68,174	34,461	2,761	72,638	36,718	2,256	77,234	39,041	2,323	81,953	41,426	2,385
9	Total	465,936	434,924	534,110	500,397	65,473	606,748	570,828	70,430	683,982	645,789	74,961	765,934	725,408	79,619

Line No.	Description	Recorded				Forecast			PTY			
		2013 (2013$)	2014 (2014$)	2015 (2015$)	2016 (2016$)	2017 (2017$)	2018 (2018$)	2019 (2019$)	**2020**	**2021**	**2022**	**2023**
10	**Escalation Rates to 2019$**	20.533%	16.932%	14.170%	12.413%	8.408%	3.743%	0.000%	3.889%	3.208%	2.618%	2.720%
11	Capital Additions (Table 11)	373,125	408,398	549,011	457,496	687,841	806,172	968,112				
12	Capital Additions (2019$)	449,740	477,546	626,804	514,283	745,678	836,345	968,112				
13	**Capital Additions 7-Year Average**							659,787	685,448	707,437	725,955	745,702
14	Capital Retirements (Table 12)	63,386	34,855	72,497	56,195	52,853	60,363	67,071				
15	Capital Retirements (2019$)	76,401	40,756	82,769	63,171	57,298	62,622	67,071				
16	**Capital Retirements 7-Year Average**							64,298	66,799	68,942	70,747	72,671
17	**Net Plant Additions for Ratebase**								618,648	638,495	655,208	673,031

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SDG&E

Table 6

San Diego Gas and Electric Company
WEIGHTED AVERAGE DEPRECIATED RATE BASE
ELECTRIC GENERATION
(Thousands of Dollars)

		2019 RO Model				**2020-2023 Attrition Year**			
		Source: Witness: R. Craig Gentes / Exhibit 379							
Line No.	Account Description	Recorded Year 2016	Estimated Year 2017	Estimated Year 2018	Test Year 2019	PTY AY 2020	PTY AY 2021	PTY AY 2022	PTY AY 2023
	Fixed Capital								
1	Plant In Service	1,013,333	1,043,695	1,066,962	1,082,514	1,105,137	1,136,219	1,167,933	1,200,229
2	Total Fixed Capital	1,013,333	1,043,695	1,066,962	1,082,514	1,105,137	1,136,219	1,167,933	1,200,229
	Working Capital								
3	Materials & Supplies	55,503	56,247	56,961	47,579	47,579	47,579	47,579	47,579
4	Working Cash	-	-	-	11,974	11,974	11,974	11,974	11,974
5	Total Working Capital	55,503	56,247	56,961	59,554	59,554	59,554	59,554	59,554
6	Repair Deductions Rate Base Adjustment (2016 - 2042)					-	-	-	-
7	Customer Advances For Construction	-	-	-	-	-	-	-	-
8	Total Other	-	-	-	-	-	-	-	-
	Deductions For Reserves								
9	Accumulated Deferred Taxes - 2017 Tax Cuts & Jobs Act Adj			29,094	27,695	26,296	24,898	23,499	22,100
10	Accumulated Depreciation Reserve	367,944	407,611	448,737	491,842	537,024	583,315	630,903	679,813
11	Accumulated Amortization Reserve	3	8	10	12	14	16	19	21
12	Accumulated Deferred Taxes	66,645	70,776	45,814	46,333	47,301	48,632	49,989	51,371
13	Total Deductions For Reserves	434,592	478,395	523,655	565,883	610,636	656,861	704,410	753,306
14	**Weighted Average Depreciated Rate Base**	634,243	621,547	600,268	576,186	554,054	538,911	523,077	506,477
15	Allocated Electric General		11,887	11,852	13,098	14,238	15,171	16,131	17,116
16	Allocated Common		24,142	29,753	34,690	37,711	40,180	42,723	45,333
17	**Total Weighted Average Rate Base**		**657,576**	**641,873**	**623,973**	**606,004**	**594,263**	**581,930**	**568,927**

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SDG&E

Table 7

San Diego Gas and Electric Company
WAVG Rate Base Support: Capital Additions, Capital Retirements, Net Depreciation and Amortization Reserve
ELECTRIC GENERATION
(Thousands of Dollars)

Line		2019 RO Model		2020-2023 Attrition Year											
		2019		2020			2021			2022			2023		
No.	Description	End of Year	WAVG	End of Year	WAVG	WAVG Increase	End of Year	WAVG	WAVG Increase	End of Year	WAVG	WAVG Increase	End of Year	WAVG	WAVG Increase
	Plant-in-Service														
1	Beginning of the Year	1,075,249	1,075,249	1,089,848	1,089,848	14,599	1,120,569	1,120,569	30,721	1,152,015	1,152,015	31,446	1,184,000	1,184,000	31,985
2	Net Plant Additions	14,599	7,265	30,721	15,289	8,024	31,446	15,649	360	31,985	15,918	268	32,612	16,230	312
3	Total	1,089,848	1,082,514	1,120,569	1,105,137	22,623	1,152,015	1,136,219	31,082	1,184,000	1,167,933	31,714	1,216,611	1,200,229	32,297
	Accumulated Depreciation Reserve														
4	Beginning of the Year	469,534	469,534	514,250	514,250	44,716	559,901	559,901	45,650	606,835	606,835	46,934	655,079	655,079	48,244
5	Net Depreciation Reserve	44,716	22,308	45,650	22,774	466	46,934	23,415	641	48,244	24,068	654	49,578	24,734	666
6	Total	514,250	491,842	559,901	537,024	45,182	606,835	583,315	46,291	655,079	630,903	47,588	704,658	679,813	48,910
	Accumulated Amortization Reserve														
7	Beginning of the Year	11	11	13	13	2	15	15	2	18	18	2	20	20	2
8	Net Amortization Reserve	2	1	2	1	0	2	1	0	2	1	0	2	1	0
9	Total	13	12	15	14	2	18	16	2	20	19	2	22	21	2

		Recorded				Forecast			PTY			
		2013 (2013$)	2014 (2014$)	2015 (2015$)	2016 (2016$)	2017 (2017$)	2018 (2018$)	2019 (2019$)	**2020**	**2021**	**2022**	**2023**
10	**Escalation Rates to 2019$**	18.441%	16.074%	11.533%	7.908%	6.193%	2.843%	0.000%	2.549%	2.358%	1.714%	1.960%
11	Capital Additions (Table 11)	34,839	42,619	6,775	22,879	50,560	20,399	19,006				
12	Capital Additions (2019$)	41,264	49,470	7,557	24,688	53,691	20,979	19,006				
13	**Capital Additions 7-Year Average**							30,951	31,740	32,488	33,045	33,693
14	Capital Retirements (Table 12)	3,211	278	58	-	837	907	938				
15	Capital Retirements (2019$)	3,803	323	65	-	889	933	938				
16	**Capital Retirements 7-Year Average**							993	1,018	1,042	1,060	1,081
17	**Net Plant Additions for Ratebase**								30,721	31,446	31,985	32,612

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SDG&E

Table 8

San Diego Gas and Electric Company
WEIGHTED AVERAGE DEPRECIATED RATE BASE
GAS DISTRIBUTION
(Thousands of Dollars)

		2019 RO Model				2020-2023 Attrition Year			
		Source: Witness: R. Craig Gentes / Exhibit 379							
Line No.	Account Description	Recorded Year 2016	Estimated Year 2017	Estimated Year 2018	Test Year 2019	PTY AY 2020	PTY AY 2021	PTY AY 2022	PTY AY 2023
	Fixed Capital								
1	Plant In Service	1,810,744	1,978,672	2,146,821	2,344,768	2,534,394	2,675,029	2,817,669	2,962,745
2	Total Fixed Capital	1,810,744	1,978,672	2,146,821	2,344,768	2,534,394	2,675,029	2,817,669	2,962,745
	Working Capital								
3	Fuel in Storage	285	285	285	285	285	285	285	285
4	Materials & Supplies	3,311	3,431	3,542	3,647	3,647	3,647	3,647	3,647
5	Working Cash	8,575	8,875	9,186	14,866	14,866	14,866	14,866	14,866
6	Total Working Capital	12,171	12,591	13,012	18,797	18,797	18,797	18,797	18,797
7	Repair Deductions Rate Base Adjustment (2016 - 2042)	-	-	-	-	-	-	-	-
8	Customer Advances For Construction	(2,340)	(2,225)	(2,079)	(2,401)	(2,401)	(2,401)	(2,401)	(2,401)
9	Total Other	(2,340)	(2,225)	(2,079)	(2,401)	(2,401)	(2,401)	(2,401)	(2,401)
	Deductions For Reserves								
10	Accumulated Deferred Taxes - 2017 Tax Cuts & Jobs Act Adj			48,913	47,036	45,159	43,283	41,406	39,529
11	Accumulated Depreciation Reserve	994,289	1,033,139	1,073,026	1,111,118	1,150,554	1,192,612	1,236,952	1,283,612
12	Accumulated Amortization Reserve	64,967	78,973	93,941	110,989	129,737	149,754	170,436	191,490
13	Accumulated Deferred Taxes	104,148	114,430	76,105	76,395	82,574	87,156	91,803	96,530
14	Total Deductions For Reserves	1,163,403	1,226,541	1,291,985	1,345,539	1,408,024	1,472,804	1,540,597	1,611,161
15	**Weighted Average Depreciated Rate Base**	657,171	762,497	865,769	1,015,626	1,142,766	1,218,622	1,293,468	1,367,981
16	**Total Weighted Average Rate Base**		**762,497**	**865,769**	**1,015,626**	**1,142,766**	**1,218,622**	**1,293,468**	**1,367,981**

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SDG&E

Table 9

San Diego Gas and Electric Company
WAVG Rate Base Support: Capital Additions, Capital Retirements, Net Depreciation and Amortization Reserve
GAS DISTRIBUTION
(Thousands of Dollars)

Line		2019 RO Model		2020-2023 Attrition Year											
Line		2019		2020			2021			2022			2023		
No.	Description	End of Year	WAVG	End of Year	WAVG	WAVG Increase	End of Year	WAVG	WAVG Increase	End of Year	WAVG	WAVG Increase	End of Year	WAVG	WAVG Increase
	Plant-in-Service														
1	Beginning of the Year	2,249,438	2,249,438	2,475,473	2,475,473	226,036	2,615,177	2,615,177	139,704	2,757,091	2,757,091	141,914	2,900,726	2,900,726	143,635
2	Net Plant Additions	226,036	95,331	139,704	58,920.09	(36,411)	141,914	59,852	932	143,635	60,578	726	147,052	62,019	1,441
3	Total	2,475,473	2,344,768	2,615,177	2,534,394	189,625	2,757,091	2,675,029	140,636	2,900,726	2,817,669	142,640	3,047,778	2,962,745	145,076
	Accumulated Depreciation Reserve														
4	Beginning of the Year	1,090,458	1,090,458	1,128,223	1,128,223	37,765	1,169,042	1,169,042	40,819	1,212,126	1,212,126	43,084	1,257,507	1,257,507	45,381
5	Net Depreciation Reserve	37,765	20,660	40,819	22,331	1,671	43,084	23,570	1,239	45,381	24,827	1,257	47,718	26,105	1,278
6	Total	1,128,223	1,111,118	1,169,042	1,150,554	39,435	1,212,126	1,192,612	42,058	1,257,507	1,236,952	44,341	1,305,225	1,283,612	46,659
	Accumulated Amortization Reserve														
7	Beginning of the Year	101,986	101,986	120,005	120,005	18,020	139,482	139,482	19,477	160,040	160,040	20,558	180,847	180,847	20,807
8	Net Amortization Reserve	18,020	9,003	19,477	9,731	728	20,558	10,271	540	20,807	10,396	125	21,302	10,643	247
9	Total	120,005	110,989	139,482	129,737	18,748	160,040	149,754	20,017	180,847	170,436	20,682	202,149	191,490	21,054

		Recorded				Forecast			PTY			
		2013 (2013$)	2014 (2014$)	2015 (2015$)	2016 (2016$)	2017 (2017$)	2018 (2018$)	2019 (2019$)	**2020**	**2021**	**2022**	**2023**
10	**Escalation Rates to 2019$**	12.458%	11.239%	12.822%	13.151%	7.405%	3.880%	0.000%	1.926%	1.582%	1.213%	2.379%
11	Capital Additions (Table 11)	79,690	73,073	108,664	113,787	194,260	168,117	224,398				
12	Capital Additions (2019$)	89,618	81,285	122,596	128,751	208,644	174,641	224,398				
13	**Capital Additions 7-Year Average**							147,133	149,967	152,339	154,188	157,855
14	Capital Retirements (Table 12)	7,509	3,065	18,489	4,706	9,122	10,568	11,673				
15	Capital Retirements (2019$)	8,445	3,410	20,859	5,325	9,797	10,978	11,673				
16	**Capital Retirements 7-Year Average**							10,069	10,263	10,426	10,552	10,803
17	**Net Plant Additions for Ratebase**								139,704	141,914	143,635	147,052

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SDG&E

Table 10

SAN DIEGO GAS & ELECTRIC
RECORDED & FORECASTED CAPITAL ADDITIONS BY FUNCTION
(Thousands of Dollars)

		RECORDED				FORECASTS		
Asset ID	Description/Function	2013	2014	2015	2016	2017	2018	2019
10	Steam Production Land	-	-	-	-	-	-	-
20	Steam Production Easements	-	-	-	-	-	-	-
30	Steam Production Other	23,306	26,633	4,751	12,602	3,387	4,922	5,336
		23,306	26,633	4,751	12,602	3,387	4,922	5,336
40	Other Production Land	-	-	-	-	-	-	-
50	Other Production Easements	54	-	-	(54)	-	-	-
60	Other Production Other	4,917	7,873	268	5,860	31,034	11,004	9,810
		4,971	7,873	268	5,807	31,034	11,004	9,810
70	Electric Transmission Assigned to Generation	(180)	-	6	725	-	-	-
80	Electric Distribution Assigned to Generation	-	-	-	-	-	-	-
90	Nuclear Generation	-	-	-	-	-	-	-
100	Electric Distribution Software & Franchises	15,264	35,585	13,877	10,457	5,621	-	-
100	Electric Distribution Software & Franchises - Fully Recovered	-	-	-	-	-	-	-
110	Electric Distribution Land	-	-	-	-	-	11,378	112
120	Electric Distribution Easements	1,446	4,946	1,617	1,575	1,270	1,941	2,051
130	Electric Distribution Other	241,254	253,543	362,537	337,601	446,588	571,350	762,730
		257,964	294,075	378,031	349,633	453,478	584,669	764,894
140	Electric Generation Assigned to Electric Distribution	5,300	834	2,216	(348)	-	-	-
150	Electric Transmission Land Assigned to Electric Distribution	-	-	893	0	-	-	-
151	Electric Transmission Easement Assigned to Electric Distribution	-	-	-	-	-	-	-
152	Electric Transmission Other Assigned to Electric Distribution	2,765	447	4,588	5,565	5,945	649	347
		8,066	1,281	7,697	5,218	5,945	649	347
160	Electric General Land & Non Depreciables	-	-	-	-	-	-	-
170	Electric General Other	34,896	35,293	21,437	27,749	8,858	44,055	6,290
		34,896	35,293	21,437	27,749	8,858	44,055	6,290
180	Gas Storage Land	-	-	-	-	-	-	-
190	Gas Storage Other	-	-	-	190	-	-	-
		-	-	-	190	-	-	-
200	Gas Transmission Land	-	-	-	-	-	-	-
210	Gas Transmission Easements	0	-	-	0	716	194	141
220	Gas Tranmission Other	32,449	16,538	31,130	29,209	17,924	12,708	16,101
		32,449	16,538	31,130	29,209	18,639	12,901	16,242
230	Gas Distribution Software & Franchises	-	-	-	-	-	-	-
230	Gas Distribution Software & Franchises - Fully Recovered	-	-	-	-	-	-	-
240	Gas Distribution & General Land	-	-	-	-	-	-	-
250	Gas Distribution & General Easements	21	74	24	10	41	43	44
260	Gas Distribution & General Other	31,800	42,549	49,435	65,750	113,572	118,304	162,546
		31,821	42,623	49,459	65,760	113,613	118,347	162,590
270	Common Software 5 Year	27,026	49,392	64,812	69,885	104,794	72,581	41,079
270	Common Software 5 Year-Fully Recovered	-	-	-	-	-	-	-
280	Common Software 15 Year	-	-	-	-	-	-	-
280	Common Software 15 Year-Fully Recovered	-	-	-	-	-	-	-
290	Common Land & Non-Depreciable Easements	0	-	-	(224)	208	314	334
300	Common IT Hardware	7,069	9,029	1,014	7,156	46,974	16,601	18,011
310	Common Other	60,266	41,353	105,845	20,453	145,729	128,645	186,581
		94,360	99,774	171,671	97,270	297,706	218,142	246,006
	Total	487,654	524,090	664,450	594,163	932,661	994,688	1,211,516

Allocation of Common IT:							
Electric Generation	6,741	8,114	1,751	3,746	16,139	4,474	3,859
Electric Distribution	72,199	77,749	141,846	74,896	219,559	176,799	196,581
Gas	15,420	13,911	28,075	18,628	62,008	36,869	45,565
	94,360	99,774	171,671	97,270	297,706	218,142	246,006

Description/Function	Asset ID	2013	2014	2015	2016	2017	2018	2019
Electric Distribution	100+110+120+130+140+150+151+152+160+170+Common IT	373,125	408,398	549,011	457,496	687,841	806,172	968,112
Electric Generation	10+20+30+40+50+60+70+80+Common IT	34,839	42,619	6,775	22,879	50,560	20,399	19,006
Gas Distribution	180+190+200+210+220+230+240+250+260+Common IT	79,690	73,073	108,664	113,787	194,260	168,117	224,398
		487,654	524,090	664,450	594,163	932,661	994,688	1,211,516

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SDG&E

Table 11

SAN DIEGO GAS & ELECTRIC
CAPITAL RETIREMENTS BY FUNCTION
(Thousands of Dollars)

		RECORDED				FORECASTS		
Asset ID	Description/Function	2013	2014	2015	2016	2017	2018	2019
10	Steam Production Land	-	-	-	-	-	-	-
20	Steam Production Easements	-	-	-	-	-	-	-
30	Steam Production Other	2,127	-	-	-	463	466	470
		2,127	0	0	0	463	466	470
40	Other Production Land	-	-	-	-	-	-	-
50	Other Production Easements	-	-	-	-	-	-	-
60	Other Production Other	108	239	29	0	72	76	78
		108	239	29	0	72	76	78
70	Electric Transmission Assigned to Generation	-	-	-	-	-	-	-
80	Electric Distribution Assigned to Generation	-	-	-	-	-	-	-
90	Nuclear Generation	-	-	-	-	-	-	-
100	Electric Distribution Software & Franchises	-	-	-	-	-	-	-
100	Electric Distribution Software & Franchises - Fully Recovered	-	-	-	-	-	-	-
110	Electric Distribution Land	-	-	-	-	-	-	-
120	Electric Distribution Easements	26	44	5	65	467	471	480
130	Electric Distribution Other	43,535	29,103	34,118	35,534	32,337	34,613	37,560
		43,562	29,148	34,123	35,599	32,805	35,084	38,040
140	Electric Generation Assigned to Electric Distribution	-	-	-	54	-	-	-
150	Electric Transmission Land Assigned to Electric Distribution	-	-	-	-	-	-	-
151	Electric Transmission Easement Assigned to Electric Distributi	-	-	-	-	-	-	-
152	Electric Transmission Other Assigned to Electric Distribution	22	192	227	453	-	-	-
		22	192	227	506	-	-	-
160	Electric General Land & Non Depreciables	-	-	-	-	-	-	-
170	Electric General Other	534	604	1,067	853	962	985	1,106
		534	604	1,067	853	962	985	1,106
180	Gas Storage Land	-	-	-	-	-	-	-
190	Gas Storage Other	-	-	-	44	-	-	-
		-	-	-	44	-	-	-
200	Gas Transmission Land	-	-	-	-	-	-	-
210	Gas Transmission Easements	0	0	0	0	3	4	4
220	Gas Tranmission Other	313	51	1,314	86	449	471	486
		313	51	1,314	86	452	475	490
230	Gas Distribution Software & Franchises	-	-	-	-	-	-	-
230	Gas Distribution Software & Franchises - Fully Recovered	-	-	-	-	-	-	-
240	Gas Distribution & General Land	-	-	-	-	-	-	-
250	Gas Distribution & General Easements	6	0	0	4	35	35	35
260	Gas Distribution & General Other	4,908	2,582	7,718	2,961	5,340	5,805	6,287
		4,914	2,583	7,719	2,965	5,376	5,840	6,323
270	Common Software 5 Year	7,222	4,249	2,075	-	-	-	-
270	Common Software 5 Year-Fully Recovered	-	-	-	-	-	-	-
280	Common Software 15 Year	-	-	-	-	-	-	-
280	Common Software 15 Year-Fully Recovered	-	-	-	-	-	-	-
290	Common Land & Non-Depreciable Easements	-	-	-	-	-	-	-
300	Common IT Hardware	1,822	37	34,690	8,975	1,828	3,483	3,963
310	Common Other	13,482	1,097	9,801	11,873	20,854	25,430	29,212
		22,526	5,383	46,567	20,848	22,683	28,913	33,176
	Total	74,106	38,198	91,044	60,901	62,812	71,838	79,682

Allocation of Common IT:							
Electric Generation	976	39	30	-	302	365	391
Electric Distribution	19,268	4,912	37,080	19,237	19,086	24,294	27,925
Gas	2,283	432	9,456	1,611	3,294	4,253	4,860
	22,526	5,383	46,567	20,848	22,683	28,913	33,176

Description/Function	Asset ID	2013	2014	2015	2016	2017	2018	2019
Electric Distribution	100+110+120+130+140+150+151+152+160+170+Common IT	63,386	34,855	72,497	56,195	52,853	60,363	67,071
Electric Generation	10+20+30+40+50+60+70+80+Common IT	3,211	278	58	-	837	907	938
Gas Distribution	180+190+200+210+220+230+240+250+260+Common IT	7,509	3,065	18,489	4,706	9,122	10,568	11,673
Total Retirements by Major Function		**74,106**	**38,198**	**91,044**	**60,901**	**62,812**	**71,838**	**79,682**

2. Capital-Related Revenue Requirement: The capital-related revenue requirement components for each attrition-year are calculated using the methodology described below:

   a) Depreciation Expense (Tables 15, 18, 21: Lines 1-7): Depreciation expense is calculated by multiplying the current PTY plant-in-service weighted average increase by the TY's system average depreciation rate (ED 4.36%, EG 4.81%, GD 3.41%).

   b) Ad Valorem Tax (Tables 15, 18, 21: Lines 8-14): Ad Valorem Tax is calculated by multiplying the current attrition-year additions by the TY's system ad valorem tax rate (ED 0.79%, EG 1.12%, GD 0.64%).

   c) State Tax Depreciation (Tables 15, 18, 21: Lines 15-23): State Tax Depreciation income tax expense is calculated by multiplying the current attrition-year additions by the TY's system average state tax depreciation rate (ED 2.94%, EG 3.32%, GD 2.98%) and by the state income tax rate (8.84%).

   d) Payroll Tax (Tables 15, 18, 21: Lines 24-28): Payroll Tax is calculated by multiplying the prior year payroll taxes by the current attrition-year labor escalation rate forecasted by Global Insight (3.17% 2020, 3.03% 2021, 3.25% 2022, 3.22% 2023).

   e) Federal Tax Depreciation (Tables 15, 18, 21: Lines 1-9): Federal Tax Depreciation income tax expense is calculated by multiplying current attrition-year additions by the TY's system average federal tax depreciation rate (ED 3.09%, EG 4.57%, GD 2.45%) and by the federal income tax rate (21%).

   f) California Corporation Franchise Tax (Prior Year) (Tables 15, 18, 21: Lines 10-28)): Prior Year's state income tax is a deduction for federal income tax purposes.

   g) Long-Term Debt Cost (Tables 17, 20, 23: Lines 4-10): Long-Term Debt Cost is calculated by multiplying the attrition-year change in WAVG rate base by the authorized weighted cost of Long Term Debt.

   h) Preferred Stock Cost (Tables 17, 20, 23: Lines 11-17): Preferred Stock Cost is calculated by multiplying the attrition-year change in WAVG rate base by the authorized weighted return on Preferred Stock.

   i) Common Equity Cost (Tables 17, 20, 23: Lines 18-24): Common Equity Cost is calculated by multiplying the attrition-year change in WAVG rate base by the authorized weighted return on Common Equity.

   j) Gross Ups: All revenue requirement components which are not directly deductible for income taxes are grossed up for income taxes by factors shown in Table 12. These components are Book Depreciation, State Tax Depreciation, Federal Tax Depreciation, Preferred Stock Cost, Common Equity Cost, and California Corporation Franchise Tax (Prior Year). All revenue requirement components are grossed up for FF&U as described in Section D.

3. Tax Law Changes: The revenue requirement estimates were calculated using current federal and state tax laws enacted through the filing date of this Petition. SDG&E's revenue requirement will reflect all tax law changes and tax rate changes, including but not limited to changes in income taxes, payroll taxes, and ad valorem taxes.

D. ADJUSTMENTS TO O&M AND CAPITAL-RELATED

1. Cost of Capital Adjustment: Per D.19-12-056 (TY 2020 Cost of Capital), SDG&E's authorized rate of return remained unchanged. Accordingly, no adjustments were performed.

2. Franchise Fees and Uncollectible Gross Up: All revenue requirement components are grossed up for FF&U as calculated in the 2019 GRC Results of Operations ("RO") Model. SDG&E's uncollectible rates have been updated using a 10-year rolling average as ordered in D.19-09-051 and adjusted in Table 1. A summary of the FF&U gross up is provided in Table 12. Detailed FF&U rate changes are included in Table 13 (Electric) and Table 14 (Gas).

Table 12

SAN DIEGO GAS & ELECTRIC COMPANY
TEST YEAR 2019
NET-TO-GROSS MULTIPLIER

		Uncollectible and Franchise Fee Factor		State & Federal Tax Factor	N-T-G Multiplier	
Line No.	Description	Electric	Gas	Electric and Gas	Electric	Gas
1	Revenues	1.000000	1.000000	1.000000	1.000000	1.000000
2	Uncollectible Tax Rate	0.001740	0.001740	0.000000	0.001740	0.001740
3	Uncollectible Amount Applied	1.000000	1.000000	1.000000	1.000000	1.000000
4	Less: Uncollectible (Line 2 * Line 3)	0.001740	0.001740	0.000000	0.001740	0.001740
5	Subtotal (Line 3 - Line 4)	0.998260	0.998260	1.000000	0.998260	0.998260
6	Franchise Fees Tax Rate	0.034468	0.020799	0.000000	0.034468	0.020799
7	Franchise Fees Amount Applied (Line 5)	0.998260	0.998260	1.000000	0.998260	0.998260
8	Less: Franchise Fees (Line 6 * Line 7)	0.034408	0.020763	0.000000	0.034408	0.020763
9	Subtotal (Line 7 - Line 8)	0.963852	0.977497	1.000000	0.963852	0.977497
10	S.I.T. Rate			0.088400	0.088400	0.088400
11	S.I.T. Amount Applied (Line 9)			1.000000	0.963852	0.977497
12	Less: S.I.T. (Line 10 * Line 11)			0.088400	0.085205	0.086411
13	Subtotal (Line 11 - Line 12)			0.911600	0.878648	0.891086
14	F.I.T. Rate			0.210000	0.210000	0.210000
15	F.I.T. Amount Applied (Line 13)			0.911600	0.878648	0.891086
16	Less: F.I.T. (Line 14 * Line 15)			0.191436	0.184516	0.187128
17	Net Operating Revenues (Line 15 - Line 16)			0.720164	0.694132	0.703958
18	Uncollectible and Franchise Fee Factor (1 / Line 9)	1.037504	1.023021			
19	State & Federal Tax Factor (1 / Line 17)			1.388573		
20	N-T-G Multiplier (1 / Line 17)				1.4406492	1.420539

Table 13

Electric

Line No.	Description	2019	2020	2021	2022	2023
1	Revenues	1.000000	1.000000	1.000000	1.000000	1.000000
2	Uncollectible Tax Rate	0.001740	0.001730	0.001690	0.001650	0.001650
3	Uncollectible Amount Applied	1.000000	1.000000	1.000000	1.000000	1.000000
4	Less: Uncollectible (L2 * L3)	0.001740	0.001730	0.001690	0.001650	0.001650
5	Subtotal (L3 - L4)	0.998260	0.998270	0.998310	0.998350	0.998350
6	Franchise Fees Tax Rate	0.034468	0.034468	0.034468	0.034468	0.034468
7	Franchise Fees Amount Applied (L5)	0.998260	0.998270	0.998310	0.998350	0.998350
8	Less: Franchise Fees (L6 * L7)	0.034408	0.034408	0.034410	0.034411	0.034411
9	Subtotal (L7 - L8)	0.963852	0.963862	0.963900	0.963939	0.963939
10	Franchise Fee and Uncollectible Factor (1 / L9)	1.037504	1.037493	1.037452	1.037410	1.037410

Table 14

Gas

Line No.	Description	2019	2020	2021	2022	2023
1	Revenues	1.000000	1.000000	1.000000	1.000000	1.000000
2	Uncollectible Tax Rate	0.001740	0.001730	0.001690	0.001650	0.001650
3	Uncollectible Amount Applied	1.000000	1.000000	1.000000	1.000000	1.000000
4	Less: Uncollectible (L2 * L3)	0.001740	0.001730	0.001690	0.001650	0.001650
5	Subtotal (L3 - L4)	0.998260	0.998270	0.998310	0.998350	0.998350
6	Franchise Fees Tax Rate	0.020799	0.020799	0.020799	0.020799	0.020799
7	Franchise Fees Amount Applied (L5)	0.998260	0.998270	0.998310	0.998350	0.998350
8	Less: Franchise Fees (L6 * L7)	0.020763	0.020763	0.020764	0.020765	0.020765
9	Subtotal (L7 - L8)	0.977497	0.977507	0.977546	0.977585	0.977585
10	Franchise Fee and Uncollectible Factor (1 / L9)	1.023021	1.023011	1.022970	1.022929	1.022929

The remaining capital-related tables are shown below.

Table 15

SAN DIEGO GAS & ELECTRIC
2019 CPUC General Rate Case (Application)
Electric Distribution
Calculation of Revenue Requirement Increase
Depreciation Expense, State Tax Depreciation, Ad Valorem Taxes, & Payroll Taxes
(Thousands of Dollars)

Line No.	Description	TY 2019	PTY 2020	PTY 2021	PTY 2022	PTY 2023
	Depreciation Expense					
1	Test Year (TY) Accrual	384,026				
2	/ TY Weighted Average (WAVG) Plant-in-Service	8,801,459				
3	= System Average Depreciation Rate	4.36%	4.36%	4.36%	4.36%	4.36%
4	x Plant in Service Weighted Average Increase		766,537	626,457	645,071	662,220
5	= Increase in Depreciation Expense		33,446	27,334	28,146	28,894
6	x Net-to-Gross Multiplier	1.440649	1.440649	1.440649	1.440649	1.440649
7	**= Increase in Revenue Requirement**		**48,183**	**39,378**	**40,548**	**41,626**
	Ad Valorem Taxes					
8	TY Ad Valorem Taxes	73,714				
9	/ TY Plant In Service	9,324,590				
10	= System Average Ad Valorem Tax Rate	0.79%	0.79%	0.79%	0.79%	0.79%
11	x Current Attrition Year Additions		618,648	638,495	655,208	673,031
12	= Increase to Ad Valorem Taxes		4,891	5,048	5,180	5,321
13	x FF&U Factor	1.037504	1.037504	1.037504	1.037504	1.037504
14	**= Increase in Revenue Requirement**		**5,074**	**5,237**	**5,374**	**5,520**
	State Regulatory Tax Depreciation					
15	TY State Tax Depreciation	274,009				
16	/ TY Plant In Service	9,324,590				
17	= System Average State Tax Depreciation Rate	2.94%	2.94%	2.94%	2.94%	2.94%
18	x Current Attrition Year Additions		618,648	638,495	655,208	673,031
19	= Increase in State Tax Depreciation Expense		18,179	18,763	19,254	19,777
20	x -State Income Tax Rate	(0.0884)	(0.0884)	(0.0884)	(0.0884)	(0.0884)
21	= State Income Taxes		(1,607)	(1,659)	(1,702)	(1,748)
22	x Net-to-Gross Multiplier	1.440649	1.440649	1.440649	1.440649	1.440649
23	**= Decrease in Revenue Requirement**		**(2,315)**	**(2,389)**	**(2,452)**	**(2,519)**
	Payroll Taxes					
24	Prior Year Payroll Taxes		10,842	11,185	11,524	11,899
25	x Current Year Labor Escalation Rate		3.17%	3.03%	3.25%	3.22%
26	= Increase in Full Year Additions		344	339	375	384
27	x FF&U Factor		1.037504	1.037504	1.037504	1.037504
28	**= Increase in Revenue Requirement**		**356**	**352**	**389**	**398**

Table 16

SAN DIEGO GAS & ELECTRIC
2019 CPUC General Rate Case (Application)
Electric Distribution
Calculation of Revenue Requirement Increase
Federal Tax Depreciation Expense & Prior Year CCFT
(Thousands of Dollars)

Line No.	Description	TY 2019	PTY 2020	PTY 2021	PTY 2022	PTY 2023
	Federal Regulatory Tax Depreciation					
1	TY Federal Tax Depreciation	288,316				
2	/ TY Plant-In-Service	9,324,590				
3	= System Average Federal Tax Depreciation Rate	3.09%	3.09%	3.09%	3.09%	3.09%
4	x Current Attrition Year Additions		618,648	638,495	655,208	673,031
5	= Increase in Federal Tax Depreciation Expense		19,129	19,742	20,259	20,810
6	x -Federal Income Tax Rate	(0.2100)	(0.2100)	(0.2100)	(0.2100)	(0.2100)
7	= Federal Income Taxes		(4,017)	(4,146)	(4,254)	(4,370)
8	x Net-to-Gross Multiplier	1.440649	1.440649	1.440649	1.440649	1.440649
9	**= Decrease in Revenue Requirement**		**(5,787)**	**(5,973)**	**(6,129)**	**(6,296)**
	California Corporation Franchise Tax (Prior Year)					
10	+ RevReq from Book Depreciation			48,183	39,378	40,548
11	+ RevReq from State Tax Depreciation			(2,315)	(2,389)	(2,452)
12	+ RevReq from Federal Tax Depreciation (ACRS.MACRS)			(5,787)	(5,973)	(6,129)
13	+ Rate Base: Preferred Stock			1,201	826	826
14	+ Rate Base: Common Stock Equity			37,455	25,750	25,762
15	+ CCFT			(808)	(1,598)	(996)
16	= Revenue Requirement Increase			77,930	55,994	57,560
17	x Prior Year State Income Tax Cumulative Component			0.088400	0.088400	0.088400
18	= Prior Year State Income Tax Increase			6,889	4,950	5,088
19	+ Prior Year State Income Tax (State Tax Depreciation Expense)			(1,607)	(1,659)	(1,702)
20	+ Prior Year State Income Tax (State Rate Change)			-	-	-
21	= Prior Year Total State Income Tax Increase			5,282	3,291	3,386
22	Prior Year Current California Corp Franchise Tax		16,637	21,919	25,210	28,597
23	- Prior Year CCFT Deductible for Federal Income Taxes		13,968	16,637	21,919	25,210
24	= Increase CCFT Deduction on Federal Income Taxes		2,669	5,282	3,291	3,386
25	x -Federal Income Tax Rate		(0.2100)	(0.2100)	(0.2100)	(0.2100)
26	= Federal Income Taxes		(561)	(1,109)	(691)	(711)
27	x Net-To-Gross Multiplier		1.440649	1.440649	1.440649	1.440649
28	**= Decrease in Revenue Requirement**		**(808)**	**(1,598)**	**(996)**	**(1,024)**

Table 17

SAN DIEGO GAS & ELECTRIC
2019 CPUC General Rate Case (Application)
Electric Distribution
Calculation of Revenue Requirement Increase
Return on Rate Base
(Thousands of Dollars)

Line No.	Description	TY 2019	PTY 2020	PTY 2021	PTY 2022	PTY 2023
	Change in Weighted Average Rate Base					
1	TY WAVG Rate Base	4,453,169	4,453,169			
2	CY WAVG Rate Base		4,943,706	5,280,954	5,618,359	5,954,024
3	Change in WAVG Rate Base		490,536	337,248	337,405	335,665
	Long Term Debt					
4	Prior Year Return on Debt	4.59%	4.59%	4.59%	4.59%	4.59%
5	x Prior Year Debt Capitalization	45.25%	45.25%	45.25%	45.25%	45.25%
6	= Prior Year Weighted Cost of Debt	2.08%	2.08%	2.08%	2.08%	2.08%
7	x Change in WAVG Rate Base		490,536	337,248	337,405	335,665
8	= Change in Weighted Cost of Debt		10,203	7,015	7,018	6,982
9	x FF&U Factor	1.037504	1.037504	1.037504	1.037504	1.037504
10	**= Increase in Revenue Requirement**		**10,586**	**7,278**	**7,281**	**7,244**
	Preferred Stock					
11	Prior Year Return on Preferred Stock	6.22%	6.22%	6.22%	6.22%	6.22%
12	x Prior Year Preferred Stock Capitalization	2.75%	2.75%	2.75%	2.75%	2.75%
13	= Prior Year Weighted Cost of Preferred Stock	0.17%	0.17%	0.17%	0.17%	0.17%
14	x Change in WAVG Rate Base		490,536	337,248	337,405	335,665
15	= Change in Weighted Cost of Preferred Stock		834	573	574	571
16	x Net-To-Gross Multiplier	1.440649	1.440649	1.440649	1.440649	1.440649
17	**= Increase in Revenue Requirement**		**1,201**	**826**	**826**	**822**
	Common Equity					
18	Prior Year Return on Common Equity	10.20%	10.20%	10.20%	10.20%	10.20%
19	x Prior Year Common Equity Capitalization	52.00%	52.00%	52.00%	52.00%	52.00%
20	= Prior Year Weighted Cost of Common Equity	5.30%	5.30%	5.30%	5.30%	5.30%
21	x Change in WAVG Rate Base		490,536	337,248	337,405	335,665
22	= Change in Weighted Cost of Common Equity		25,998	17,874	17,882	17,790
23	x Net-To-Gross Multiplier	1.440649	1.440649	1.440649	1.440649	1.440649
24	**= Increase in Revenue Requirement**		**37,455**	**25,750**	**25,762**	**25,630**
25	**Total Increase in ED Revenue Requirement**		**93,946**	**68,861**	**70,604**	**71,401**

Table 18

SAN DIEGO GAS & ELECTRIC
2019 CPUC General Rate Case (Application)
Electric Generation
Calculation of Revenue Requirement Increase
Depreciation Expense, State Tax Depreciation, Ad Valorem Taxes, & Payroll Taxes
(Thousands of Dollars)

Line No.	Description	TY 2019	PTY 2020	PTY 2021	PTY 2022	PTY 2023
	Depreciation Expense					
1	Test Year (TY) Accrual	52,031				
2	/ TY Weighted Average (WAVG) Plant-in-Service	1,082,514				
3	= System Average Depreciation Rate	4.81%	4.81%	4.81%	4.81%	4.81%
4	x Plant in Service Weighted Average Increase		22,623	31,082	31,714	32,297
5	= Increase in Depreciation Expense		1,087	1,494	1,524	1,552
6	x Net-to-Gross Multiplier	1.440649	1.440649	1.440649	1.440649	1.440649
7	**= Increase in Revenue Requirement**		**1,566**	**2,152**	**2,196**	**2,236**
	Ad Valorem Taxes					
8	TY Ad Valorem Taxes	12,183				
9	/ TY Plant In Service	1,089,848				
10	= System Average Ad Valorem Tax Rate	1.12%	1.12%	1.12%	1.12%	1.12%
11	x Current Attrition Year Additions		30,721	31,446	31,985	32,612
12	= Increase to Ad Valorem Taxes		343	352	358	365
13	x FF&U Factor	1.037504	1.037504	1.037504	1.037504	1.037504
14	**= Increase in Revenue Requirement**		**356**	**365**	**371**	**378**
	State Regulatory Tax Depreciation					
15	TY State Tax Depreciation	36,175				
16	/ TY Plant In Service	1,089,848				
17	= System Average State Tax Depreciation Rate	3.32%	3.32%	3.32%	3.32%	3.32%
18	x Current Attrition Year Additions		30,721	31,446	31,985	32,612
19	= Increase in State Tax Depreciation Expense		1,020	1,044	1,062	1,082
20	x -State Income Tax Rate	(0.0884)	(0.0884)	(0.0884)	(0.0884)	(0.0884)
21	= State Income Taxes		(90)	(92)	(94)	(96)
22	x Net-to-Gross Multiplier	1.440649	1.440649	1.440649	1.440649	1.440649
23	**= Decrease in Revenue Requirement**		**(130)**	**(133)**	**(135)**	**(138)**
	Payroll Taxes					
24	Prior Year Payroll Taxes		906	935	963	995
25	x Current Year Labor Escalation Rate		3.17%	3.03%	3.25%	3.22%
26	= Increase in Full Year Additions		29	28	31	32
27	x FF&U Factor		1.037504	1.037504	1.037504	1.037504
28	**= Increase in Revenue Requirement**		**30**	**29**	**33**	**33**

Table 19

SAN DIEGO GAS & ELECTRIC
2019 CPUC General Rate Case (Application)
Electric Generation
Calculation of Revenue Requirement Increase
Federal Tax Depreciation Expense & Prior Year CCFT
(Thousands of Dollars)

Line No.	Description	TY 2019	PTY 2020	PTY 2021	PTY 2022	PTY 2023
	Federal Regulatory Tax Depreciation					
1	TY Federal Tax Depreciation	49,761				
2	/ TY Plant-In-Service	1,089,848				
3	= System Average Federal Tax Depreciation Rate	4.57%	4.57%	4.57%	4.57%	4.57%
4	x Current Attrition Year Additions		30,721	31,446	31,985	32,612
5	= Increase in Federal Tax Depreciation Expense		1,403	1,436	1,460	1,489
6	x -Federal Income Tax Rate	(0.2100)	(0.2100)	(0.2100)	(0.2100)	(0.2100)
7	= Federal Income Taxes		(295)	(302)	(307)	(313)
8	x Net-to-Gross Multiplier	1.440649	1.440649	1.440649	1.440649	1.440649
9	**= Decrease in Revenue Requirement**		**(424)**	**(434)**	**(442)**	**(450)**
	California Corporation Franchise Tax (Prior Year)					
10	+ RevReq from Book Depreciation			1,566	2,152	2,196
11	+ RevReq from State Tax Depreciation			(130)	(133)	(135)
12	+ RevReq from Federal Tax Depreciation (ACRS.MACRS)			(424)	(434)	(442)
13	+ Rate Base: Preferred Stock			(44)	(29)	(30)
14	+ Rate Base: Common Stock Equity			(1,372)	(897)	(942)
15	+ CCFT			(122)	41	9
16	= Revenue Requirement Increase			(526)	701	656
17	x Prior Year State Income Tax Cumulative Component			0.088400	0.088400	0.088400
18	= Prior Year State Income Tax Increase			(47)	62	58
19	+ Prior Year State Income Tax (State Tax Depreciation Expense)			(90)	(92)	(94)
20	+ Prior Year State Income Tax (State Rate Change)			-	-	-
21	= Prior Year Total State Income Tax Increase			(137)	(30)	(36)
22	Prior Year Current California Corp Franchise Tax		5,801	5,665	5,634	5,598
23	- Prior Year CCFT Deductible for Federal Income Taxes		5,397	5,801	5,665	5,634
24	= Increase CCFT Deduction on Federal Income Taxes		404	(137)	(30)	(36)
25	x -Federal Income Tax Rate		(0.2100)	(0.2100)	(0.2100)	(0.2100)
26	= Federal Income Taxes		(85)	29	6	8
27	x Net-To-Gross Multiplier		1.440649	1.440649	1.440649	1.440649
28	**= Increase in Revenue Requirement**		**(122)**	**41**	**9**	**11**

Table 20

SAN DIEGO GAS & ELECTRIC
2019 CPUC General Rate Case (Application)
Electric Generation
Calculation of Revenue Requirement Increase
Return on Rate Base
(Thousands of Dollars)

Line No.	Description	TY 2019	PTY 2020	PTY 2021	PTY 2022	PTY 2023
	Change in Weighted Average Rate Base					
1	TY WAVG Rate Base	623,973	623,973			
2	CY WAVG Rate Base		606,004	594,263	581,930	568,927
3	Change in WAVG Rate Base		(17,969)	(11,742)	(12,332)	(13,004)
	Long Term Debt					
4	Prior Year Return on Debt	4.59%	4.59%	4.59%	4.59%	4.59%
5	x Prior Year Debt Capitalization	45.25%	45.25%	45.25%	45.25%	45.25%
6	= Prior Year Weighted Cost of Debt	2.08%	2.08%	2.08%	2.08%	2.08%
7	x Change in WAVG Rate Base		(17,969)	(11,742)	(12,332)	(13,004)
8	= Change in Weighted Cost of Debt		(374)	(244)	(257)	(270)
9	x FF&U Factor	1.037504	1.037504	1.037504	1.037504	1.037504
10	**= Increase (Decrease) in Revenue Requirement**		**(388)**	**(253)**	**(266)**	**(281)**
	Preferred Stock					
11	Prior Year Return on Preferred Stock	6.22%	6.22%	6.22%	6.22%	6.22%
12	x Prior Year Preferred Stock Capitalization	2.75%	2.75%	2.75%	2.75%	2.75%
13	= Prior Year Weighted Cost of Preferred Stock	0.17%	0.17%	0.17%	0.17%	0.17%
14	x Change in WAVG Rate Base		(17,969)	(11,742)	(12,332)	(13,004)
15	= Change in Weighted Cost of Preferred Stock		(31)	(20)	(21)	(22)
16	x Net-To-Gross Multiplier	1.440649	1.440649	1.440649	1.440649	1.440649
17	**= Increase (Decrease) in Revenue Requirement**		**(44)**	**(29)**	**(30)**	**(32)**
	Common Equity					
18	Prior Year Return on Common Equity	10.20%	10.20%	10.20%	10.20%	10.20%
19	x Prior Year Common Equity Capitalization	52.00%	52.00%	52.00%	52.00%	52.00%
20	= Prior Year Weighted Cost of Common Equity	5.30%	5.30%	5.30%	5.30%	5.30%
21	x Change in WAVG Rate Base		(17,969)	(11,742)	(12,332)	(13,004)
22	= Change in Weighted Cost of Common Equity		(952)	(622)	(654)	(689)
23	x Net-To-Gross Multiplier	1.440649	1.440649	1.440649	1.440649	1.440649
24	**= Increase (Decrease) in Revenue Requirement**		**(1,372)**	**(897)**	**(942)**	**(993)**
25	**Total Increase in EG Revenue Requirement**		**(528)**	**842**	**794**	**765**

Table 21

SAN DIEGO GAS & ELECTRIC
2019 CPUC General Rate Case (Application)
Gas Distribution
Calculation of Revenue Requirement Increase
Depreciation Expense, State Tax Depreciation, Ad Valorem Taxes, & Payroll Taxes
(Thousands of Dollars)

Line No.	Description	TY 2019	PTY 2020	PTY 2021	PTY 2022	PTY 2023
	Depreciation Expense					
1	Test Year (TY) Accrual	79,929				
2	/ TY Weighted Average (WAVG) Plant-in-Service	2,344,768				
3	= System Average Depreciation Rate	3.41%	3.41%	3.41%	3.41%	3.41%
4	x Plant in Service Weighted Average Increase		189,625	140,636	142,640	145,076
5	= Increase in Depreciation Expense		6,464	4,794	4,862	4,945
6	x Net-to-Gross Multiplier	1.420539	1.420539	1.420539	1.420539	1.420539
7	**= Increase in Revenue Requirement**		**9,182**	**6,810**	**6,907**	**7,025**
	Ad Valorem Taxes					
8	TY Ad Valorem Taxes	15,902				
9	/ TY Plant In Service	2,475,473				
10	= System Average Ad Valorem Tax Rate	0.64%	0.64%	0.64%	0.64%	0.64%
11	x Current Attrition Year Additions		139,704	141,914	143,635	147,052
12	= Increase to Ad Valorem Taxes		897	912	923	945
13	x FF&U Factor	1.023021	1.023021	1.023021	1.023021	1.023021
14	**= Increase in Revenue Requirement**		**918**	**933**	**944**	**966**
	State Regulatory Tax Depreciation					
15	TY State Tax Depreciation	73,871				
16	/ TY Plant In Service	2,475,473				
17	= System Average State Tax Depreciation Rate	2.98%	2.98%	2.98%	2.98%	2.98%
18	x Current Attrition Year Additions		139,704	141,914	143,635	147,052
19	= Increase in State Tax Depreciation Expense		4,169	4,235	4,286	4,388
20	x -State Income Tax Rate	(0.0884)	(0.0884)	(0.0884)	(0.0884)	(0.0884)
21	= State Income Taxes		(369)	(374)	(379)	(388)
22	x Net-to-Gross Multiplier	1.420539	1.420539	1.420539	1.420539	1.420539
23	**= Decrease in Revenue Requirement**		**(524)**	**(532)**	**(538)**	**(551)**
	Payroll Taxes					
24	Prior Year Payroll Taxes		5,645	5,824	6,001	6,196
25	x Current Year Labor Escalation Rate		3.17%	3.03%	3.25%	3.22%
26	= Increase in Full Year Additions		179	177	195	200
27	x FF&U Factor		1.023021	1.023021	1.023021	1.023021
28	**= Increase in Revenue Requirement**		**183**	**181**	**200**	**204**

Table 22

SAN DIEGO GAS & ELECTRIC
2019 CPUC General Rate Case (Application)
Gas Distribution
Calculation of Revenue Requirement Increase
Federal Tax Depreciation Expense & Prior Year CCFT
(Thousands of Dollars)

Line No.	Description	TY 2019	PTY 2020	PTY 2021	PTY 2022	PTY 2023
	Federal Regulatory Tax Depreciation					
1	TY Federal Tax Depreciation	60,683				
2	/ TY Plant-In-Service	2,475,473				
3	= System Average Federal Tax Depreciation Rate	2.45%	2.45%	2.45%	2.45%	2.45%
4	x Current Attrition Year Additions		139,704	141,914	143,635	147,052
5	= Increase in Federal Tax Depreciation Expense		3,425	3,479	3,521	3,605
6	x -Federal Income Tax Rate	(0.2100)	(0.2100)	(0.2100)	(0.2100)	(0.2100)
7	= Federal Income Taxes		(719)	(731)	(739)	(757)
8	x Net-to-Gross Multiplier	1.420539	1.420539	1.420539	1.420539	1.420539
9	**= Decrease in Revenue Requirement**		**(1,022)**	**(1,038)**	**(1,050)**	**(1,075)**
	California Corporation Franchise Tax (Prior Year)					
10	+ RevReq from Book Depreciation			9,182	6,810	6,907
11	+ RevReq from State Tax Depreciation			(524)	(532)	(538)
12	+ RevReq from Federal Tax Depreciation (ACRS.MACRS)			(1,022)	(1,038)	(1,050)
13	+ Rate Base: Preferred Stock			307	183	181
14	+ Rate Base: Common Stock Equity			9,572	5,711	5,635
15	+ CCFT			(672)	(334)	(173)
16	= Revenue Requirement Increase			16,844	10,801	10,961
17	x Prior Year State Income Tax Cumulative Component			0.088400	0.088400	0.088400
18	= Prior Year State Income Tax Increase			1,489	955	969
19	+ Prior Year State Income Tax (State Tax Depreciation Expense)			(369)	(374)	(379)
20	+ Prior Year State Income Tax (State Rate Change)			-	-	-
21	= Prior Year Total State Income Tax Increase			1,121	580	590
22	Prior Year Current California Corp Franchise Tax		4,629	5,749	6,330	6,920
23	- Prior Year CCFT Deductible for Federal Income Taxes		2,376	4,629	5,749	6,330
24	= Increase CCFT Deduction on Federal Income Taxes		2,253	1,121	580	590
25	x -Federal Income Tax Rate		(0.2100)	(0.2100)	(0.2100)	(0.2100)
26	= Federal Income Taxes		(473)	(235)	(122)	(124)
27	x Net-To-Gross Multiplier		1.420539	1.420539	1.420539	1.420539
28	**= Decrease in Revenue Requirement**		**(672)**	**(334)**	**(173)**	**(176)**

Table 23

SAN DIEGO GAS & ELECTRIC
2019 CPUC General Rate Case (Application)
Gas Distribution
Calculation of Revenue Requirement Increase
Return on Rate Base
(Thousands of Dollars)

Line No.	Description	TY 2019	PTY 2020	PTY 2021	PTY 2022	PTY 2023
	Change in Weighted Average Rate Base					
1	TY WAVG Rate Base	1,015,626	1,015,626			
2	CY WAVG Rate Base		1,142,766	1,218,622	1,293,468	1,367,981
3	Change in WAVG Rate Base		127,141	75,856	74,846	74,513
	Long Term Debt					
4	Prior Year Return on Debt	4.59%	4.59%	4.59%	4.59%	4.59%
5	x Prior Year Debt Capitalization	45.25%	45.25%	45.25%	45.25%	45.25%
6	= Prior Year Weighted Cost of Debt	2.08%	2.08%	2.08%	2.08%	2.08%
7	x Change in WAVG Rate Base		127,141	75,856	74,846	74,513
8	= Change in Weighted Cost of Debt		2,645	1,578	1,557	1,550
9	x FF&U Factor	1.023021	1.023021	1.023021	1.023021	1.023021
10	**= Increase in Revenue Requirement**		**2,705**	**1,614**	**1,593**	**1,586**
	Preferred Stock					
11	Prior Year Return on Preferred Stock	6.22%	6.22%	6.22%	6.22%	6.22%
12	x Prior Year Preferred Stock Capitalization	2.75%	2.75%	2.75%	2.75%	2.75%
13	= Prior Year Weighted Cost of Preferred Stock	0.17%	0.17%	0.17%	0.17%	0.17%
14	x Change in WAVG Rate Base		127,141	75,856	74,846	74,513
15	= Change in Weighted Cost of Preferred Stock		216	129	127	127
16	x Net-To-Gross Multiplier	1.420539	1.420539	1.420539	1.420539	1.420539
17	**= Increase in Revenue Requirement**		**307**	**183**	**181**	**180**
	Common Equity					
18	Prior Year Return on Common Equity	10.20%	10.20%	10.20%	10.20%	10.20%
19	x Prior Year Common Equity Capitalization	52.00%	52.00%	52.00%	52.00%	52.00%
20	= Prior Year Weighted Cost of Common Equity	5.30%	5.30%	5.30%	5.30%	5.30%
21	x Change in WAVG Rate Base		127,141	75,856	74,846	74,513
22	= Change in Weighted Cost of Common Equity		6,738	4,020	3,967	3,949
23	x Net-To-Gross Multiplier	1.420539	1.420539	1.420539	1.420539	1.420539
24	**= Increase in Revenue Requirement**		**9,572**	**5,711**	**5,635**	**5,610**
25	**Total Increase in GD Revenue Requirement**		**20,651**	**13,528**	**13,698**	**13,769**

ATTACHMENT C

JESSE S. ARAGON DECLARATION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U 902 M) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019.	Application No. 17-10-007 (Filed October 6, 2017)
And Related Matter.	Application No. 17-10-008 (Filed October 6, 2017)

DECLARATION OF JESSE S. ARAGON ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY IN SUPPORT OF THE JOINT PETITION FOR MODIFICATION OF D.19-09-051

I, Jesse S. Aragon, declare that:

1. I am currently employed by Southern California Gas Company ("SoCalGas") as the Director of Financial and Operational Planning. My current responsibilities include financial planning, operational budgeting and treasury for all capital, operating expenses, and cashflow.

2. I have reviewed the Petition for Modification ("Petition") of Decision ("D.") D.19-09-051, the Decision Addressing the Test Year ("TY") 2019 General Rate Cases ("GRCs") of SoCalGas and San Diego Gas & Electric Company ("SDG&E"), approved on September 26, 2019 (hereinafter referred to as the "2019 GRC Decision"). The purpose of my declaration is to provide the factual support for SoCalGas' proposal for two additional attrition years, 2022 and 2023.

3. As described in the Petition, the Commission's recent decision in Rulemaking ("R.") 13-11-006 (the "Rate Case Plan" or "RCP Rulemaking"), D.20-01-002 (hereinafter referred to as the "RCP Decision"), extends the GRC cycle for each large California investor-owned utility ("IOU") from three to four years. The Petition implements requirements of the

RCP Decision by proposing just and reasonable interim 2022 and 2023 attrition year increases for SoCalGas and SDG&E, consistent with the RCP Decision's transition schedule to a four-year cycle for all IOUs. Specifically, the Petition asks the Commission to continue SoCalGas' approved post-test year ("PTY") mechanism into 2022 and 2023.

The 2019 GRC Decision Approved a Post-Test Year Mechanism for 2020 and 2021.

4. The RCP Decision describes the general methodology for updating revenue requirement results for attrition years as follows: "The post-test year revenue requirements are typically determined by (1) escalating the test year O&M expenses, and (2) authorizing capital expenditures at a level determined by either (i) applying additional escalation factors, or (ii) further review of the applicant utility's actual capital budgets for those years."[1]

5. Here, for SoCalGas' and SDG&E's authorized PTY mechanism, the 2019 GRC Decision approved a two-part attrition mechanism for post-test years 2020 and 2021, where capital-related revenues and Operations and Maintenance ("O&M") expenses are separately escalated.[2] The Commission authorized the post-test year mechanism as part of an extensive review of the record evidence in this proceeding, including various proposals presented by different parties.[3] The authorized attrition mechanism is based on the following:

- **Capital Adjustment:** seven-year average of recorded and forecasted capital additions (2013-2019) that are escalated using IHS Markit Global Insight ("Global Insight") indices to 2019 dollars and then averaged; 2020 and 2021 are determined by escalating the seven-year average using the Global Insight indices.[4]

- **O&M Adjustment:** labor and non-labor (including medical) O&M are escalated using Global Insight indices.[5]

[1] D.20-01-002 at 8.
[2] D.19-09-051 at 705.
[3] *Id.* at 705-706.
[4] *Id.* at 708-710.
[5] *Id.* at 708.

6. SoCalGas' authorized PTY mechanism is based on an escalated seven-year average of recorded and forecasted capital additions, not on a continued review of actual capital costs. The 2019 GRC Decision also approved the continuation of SoCalGas' previously authorized Z-Factor mechanisms.[6] In addition, the authorized PTY mechanism includes a separate component for the Pipeline Safety Enhancement Plan ("PSEP") in the post-test years. PSEP-related post-test year information is further discussed below and in the declaration of Deana Ng (Attachment D).

The Evidentiary Record in the Above-Captioned Proceeding Supports Continuing the Post-Test Year Mechanism for 2022 & 2023.

7. The Petition proposes to extend SoCalGas' PTY mechanism adopted in the 2019 GRC Decision to attrition years 2022 and 2023. Consistent with the approved PTY mechanism, SoCalGas' proposed attrition year 2022 and 2023 increases for non-PSEP capital investments are based on an escalated (using Commission-approved Global Insight indices) seven-year average of capital additions authorized in the 2019 GRC Decision. O&M expenses (including medical) will also continue to be escalated using the Global Insight index approved in the 2019 GRC Decision. SoCalGas performed updates for 2022 and 2023, as outlined in the declaration of Ryan Hom (Attachment A). These updates are included in SoCalGas' proposal to continue the post-test year mechanism.

8. Applying the same post-test year methodology adopted in the 2019 GRC Decision for O&M and non-PSEP capital, as explained above, and making limited updates to escalation factors, yields attrition-year revenue increases of $129.2 million (4.17 percent) in 2022 and $131.4 million (4.07 percent) in 2023, as shown in Table 1 below. Workpapers detailing the

[6] *Id.*, Ordering Paragraph ("OP") 4 at 776.

post-test year mechanism are attached to this declaration, as Attachments C.1 and C.2.

Table 1: SoCalGas Proposed Post-Test Years Attrition Adjustments for O&M and Non-PSEP Capital[7]

	*Approved **		*Proposed*	
($ in millions)	**2020**	**2021**	**2022**	**2023**
O&M Adjustments	36.1	33.3	37.4	39.9
Capital Adjustments	167.0	90.3	91.8	91.5
Revenue Requirement Adjustments	203.1	123.6	129.2	131.4

* 2020 and 2021 figures adjusted for cost of capital and uncollectible rates per D.19-12-056 and D.19-09-051, respectively.

Continuation of the CPUC's Approved Post-Test Year Mechanism for 2022 & 2023 is Reasonable and Should be Adopted.

9. The adopted attrition methodology in the 2019 GRC Decision is appropriate for this Petition, as it has been thoroughly examined and litigated as part of the GRC process. Extending the PTY mechanism to 2022 and 2023 is reasonable, including for the many reasons outlined in SoCalGas' testimony in this proceeding.[8]

10. SoCalGas' and SDG&E's PTY witnesses testified to their evolving capital programs, with a greater focus on increasing investment in utility safety, reliability, grid modernization and clean energy, which directly support California's energy policies.[9] The PTY witnesses testified to Petitioners' S-MAP and RAMP focus, and that through these proceedings, SoCalGas and SDG&E would continue to identify necessary investment opportunities in safety and reliability through the new risk management tools and processes in upcoming years.[10] SoCalGas' and SDG&E's risk management and policy witness also testified to Petitioners' detailed commitment through 2025 and beyond on how they will "continue to build on the progress made thus far to develop their risk, asset, and investment management programs and the

[7] Figures may not add due to rounding.
[8] *See* Ex. 242 (SoCalGas Malik 2nd Revised Direct) at JAM-3.
[9] *Id.* at JAM-8; Ex. 245 (SDG&E Deremer 2nd Revised Direct) at KJD-7.
[10] *Id.* at JAM-8; *Id.* at KJD-7.

overall integration of the three"[11] and on "working with stakeholders during this GRC cycle, and beyond, to meet Commission directives."[12] The Commission's adopted PTY mechanism for capital-related costs captures the recent S-MAP and RAMP focus and historical increase in capital additions and reflects SoCalGas' and SDG&E's evolving priorities in these areas.

11. Continuing the authorized post-test year mechanism through 2022 and 2023 is thus beneficial for the same reasons the Commission provided in authorizing it for 2020 and 2021, as found in the 2019 GRC Decision, because it "reasonably reflects … historical adjustments as well as current and forward-looking [capital] additions,"[13] "provides a more effective normalization of capital additions,"[14] while at the same time maintains SoCalGas' "forward-looking focus and increased programs on improving safety, risk mitigation, … and support of California's clean energy and environmental initiatives."[15]

A PSEP Capital-Related Revenue Requirement Should Continue for 2022 and 2023.

12. In D.16-08-003, the Commission directed SoCalGas to include certain PSEP costs as part of the 2019 General Rate Case:

> Southern California Gas Company and San Diego Gas & Electric Company are authorized to include in their 2019 General Rate Case (GRC) application all Pipeline Safety Enhancement Plan costs not the subject of prior applications, including possible review of any remaining 2018 Phase 1A and 1B capital costs. Future GRC applications could include Pipeline Safety Enhancement Plan costs until implementation of the Plan is complete.[16]

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[11] Ex. 3 (SoCalGas/SDG&E Day Revised Direct) at DD-24.
[12] *Id.* at DD-25.
[13] D.19-09-051 at 708.
[14] *Id.* at 709.
[15] *Id.* at 709.
[16] D.16-08-003, OP 5 at 16

13. In the 2019 GRC Application, SoCalGas presented detailed support for PSEP projects for the years 2019-2022.[17] In addition to seeking Commission approval of these PSEP projects and the associated funding, "SoCalGas propose[d] that the PSEP capital-related costs not fully reflected in the TY 2019 revenue requirement be included as part of the PTY attrition to ensure that shareholders are provided the necessary revenue to have a reasonable opportunity to earn its authorized ROR [rate of return] in the PTY period."[18] SoCalGas further stated that this "adjustment is necessary because the majority of PSEP capital expenditures are expected to close to plant in service in 2020, 2021, and 2022, and therefore the associated capital-related costs will not be fully reflected in the TY 2019 revenue requirement."[19]

14. The PTY PSEP capital-related revenue requirement, as originally proposed in SoCalGas' 2019 GRC Application, was based on specific PSEP capital forecasts beyond TY 2019. The capital additions that contribute to the revenue requirement were based on these forecasts proposed by SoCalGas witness Rick Phillips[20] and were calculated for each year of the requested post-test years (2020, 2021, and 2022).

15. In the 2019 GRC Decision, the Commission found that SoCalGas' approach to calculating the revenue requirement associated with the PSEP PTY capital additions reasonable:

> We also find SoCalGas' proposal that PSEP capital-related costs not fully reflected in the TY2019 revenue requirement be included as part of the PTYs reasonable and we approve it. This is because PSEP is being incorporated into the GRC for the first time and timing and completion of the proposed projects

[17] *See* Ex. 231 (SoCalGas/Phillips), Ex. 232 (SoCalGas/Phillips), Ex. 233C (SoCalGas/Phillips), Ex. 233R (SoCalGas/Phillips), Ex. 234 (SoCalGas/Phillips), Ex. 235 (SoCalGas/Phillips and Chaudhury), and Ex. 235A (SoCalGas/Phillips).
[18] Ex. 242 (SoCalGas Malik 2nd Revised Direct) at JAM-9.
[19] *Id.* at JAM-9.
[20] *See* Ex. 231 (SoCalGas/Phillips).

> should not be delayed. We find the adjustment necessary in order to fully reflect the capital costs we are authorizing but will not be fully reflected in the TY.[21]

16. Accordingly, the 2019 GRC Decision authorized SoCalGas a separate revenue requirement for PSEP in the PTY mechanism for years 2020 and 2021, which includes a forecast of PSEP capital additions beyond TY 2019.[22] It also, however, denied SoCalGas' PTY proposal for a 2022 PSEP capital-related revenue requirement, consistent with its denial of a third attrition year: "we are rejecting SoCalGas' request to change their current three-year GRC cycles into a four-year cycle and so we deny approval of the fourth year PSEP projects as this GRC cycle will only include TY2019 and PTYs 2020 and 2021."[23]

17. In this Petition, SoCalGas is proposing to continue the authorized PSEP PTY mechanism where a separate capital-related revenue requirement for 2022 and 2023 is calculated based on forecasted capital additions. As explained in Ms. Ng's Declaration (Attachment D), for 2022, SoCalGas is proposing to use the PSEP projects presented in the record of this proceeding as the basis for computing capital additions. Ms. Ng also describes that SoCalGas is not proposing additional capital forecasts for 2023 in this Petition. Rather, SoCalGas is requesting to calculate capital additions for 2023 on the PSEP projects already presented for 2022 (and approved in 2019-2021) in the evidentiary record of the instant proceeding.

18. Specifically, to calculate the 2022 and 2023 revenue requirement associated with SoCalGas' Petition proposal, the following adjustments were made to the authorized PTY PSEP capital-related revenue requirement calculation:

a. The logic in the 2019 GRC Decision's PSEP PTY workpapers were extended additional years in order to capture the 2022 and 2023 capital-related revenue requirement, as proposed in this Petition.

[21] D.19-09-051 at 215-216.
[22] *Id.*, OP 4 at 776.
[23] *Id.* at 216.

b. The 2022 PSEP capital forecasts for projects with an in-service date of 2022 that were removed from the 2019 GRC Decision workpapers, were added back and modeled in the workpapers from Step 1 above. These 2022 PSEP capital forecasts were presented in SoCalGas' 2019 GRC Application[24] and are also discussed in Ms. Ng's Declaration. When adding back these 2022 PSEP capital forecasts, SoCalGas applied the adjustments adopted by the Commission in the 2019 GRC Decision for PSEP project forecasts to the 2022 PSEP project capital forecasts originally presented in the 2019 GRC Application.[25]

c. No new capital forecasts (i.e., capital expenditures) for 2023 were included.

d. Limited updates were applied, as described in Mr. Hom's declaration, including uncollectible rates, escalation factors, and authorized rate of return.

19. SoCalGas' PSEP capital-related revenue requirements, authorized for 2020 and 2021 and requested in this Petition for 2022 and 2023, are provided in Table 2 below:

Table 2: SoCalGas Proposed PSEP Post-Test Years Attrition Adjustments

	Approved		*Proposed*	
($ in millions)	**2020**	**2021**	**2022**	**2023**
PSEP Capital Rev Req Adjustment *	12.7	25.2	25.9	5.5
Total PSEP Capital Expenditures	154.0	204.4	36.7	0.0

* Figures not adjusted for cost of capital and uncollectible rates.

20. The continuation of a distinct PSEP capital-related revenue requirement is needed because, similar to the approval in the 2019 GRC Decision, SoCalGas continues to forecast PSEP work that will close to plant in service in 2022 and 2023 that is not accounted for in the traditional post-test year mechanism. SoCalGas' PSEP proposal in this Petition is consistent with the record of this proceeding and the 2019 GRC Decision, in that it is forecasting capital additions as the basis for the PTY revenue requirement.

[24] *See* Ex. 231 (SoCalGas/Philips) at Section X.

[25] D.19-09-051, Conclusion of Law 44 at 766, ("The approved PSEP capital projects should be subject to a 10 percentage points reduction of the risk adjustment component."); *see also* D.19-09-051 at 215 ("The Line 44-1008 replacement project is not authorized.")

Post-Test Year Revenue Requirement Increases for 2022 & 2023.

21. Based on the foregoing, Table 3 below presents a summary of SoCalGas' post-test year revenue requirement proposals for 2022 and 2023. These proposals include: (1) an O&M adjustment; (2) a capital-related adjustment (without PSEP); (3) a PSEP capital-related adjustment; and (4) a reflection of the updates for uncollectibles rates, escalation factors, and rate of return. As shown in Table 3 below, SoCalGas' proposed attrition-year revenue increases are $155.1 million (4.95 percent) in 2022 and $136.8 million (4.16 percent) in 2023. Workpapers detailing the post-test year mechanism are attached to this declaration as Attachments C.1 and C.2.

Table 3: Summary of SoCalGas Proposed Post-Test Year Attrition[26]

	Approved		*Proposed*	
($ in millions)	**2020**	**2021**	**2022**	**2023**
O&M Adjustments	36.1	33.3	37.4	39.9
Capital Adjustments	167.0	90.3	91.8	91.5
Revenue Requirement Adjustments	203.1	123.6	129.2	131.4
PSEP Capital Adjustments	12.7	25.2	25.9	5.5
Revenue Requirement Adjustments *	215.8	148.9	155.1	136.8

* 2020 and 2021 figures adjusted for cost of capital and uncollectible rates per D.19-12-056 and D.19-09-051, respectively.

22. I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, except as to those matters stated to be on information and belief, and as to those matters, I believe them to be true and correct.

Executed this 9th day of April 2020, at Los Angeles, California.

/s/ Jesse S. Aragon
Jesse S. Aragon

[26] Figures may not add due to rounding.

ATTACHMENT C.1

SOCALGAS WORKPAPERS TO DECLARATION OF JESSE S. ARAGON ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY

TABLE OF CONTENTS

PETITION FOR MODIFICATION

This attachment provides detailed information, as required by Decision ("D.") 20-01-002, in support of SoCalGas' attrition year requests for 2022 and 2023. This attachment also reflects the updates to uncollectible rates, escalation factors, and cost of capital as outlined in Ryan Hom's Declaration (Attachment A to the Petition for Modification).

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SOCALGAS

A. REVENUE REQUIREMENT

This Post-Test Year ("PTY") ratemaking mechanism proposes to update the Test Year ("TY") authorized revenue requirement for purposes of adding two additional attrition years, 2022 and 2023. The adopted PTY ratemaking mechanism escalates revenue requirement in PTY's 2020, 2021, 2022, and 2023 for:

1. Labor and non-labor operation and maintenance costs (including medical) based on IHS/Markit Global Insight's ("GI") forecast (Section B), and
2. Calculating PTY capital-related revenue requirements using:
    a) An escalated 7-year average level of capital additions (Section C), and
    b) A forecast for Pipeline Safety Enhancement Plan ("PSEP") capital additions beyond TY 2019 (Section E).

The base margin amounts utilized throughout these workpapers to determine the revenue requirements in 2022 and 2023 were adopted in SoCalGas' TY 2019 GRC Decision, D.19-09-051. SoCalGas then reflected the TY 2020 Cost of Capital ("COC") decision, D.19-12-056 and updated the uncollectible rates[1] using a 10-year rolling average as ordered in D.19-09-051 and illustrated in Table 7. Additionally, SoCalGas added logic changes to incorporate the COC and uncollectible updates and updates for escalation factors. These changes are reflected in the PTY model for years 2020-2023.

In preparing this workpaper, SoCalGas applied the updates above to the PTYs 2020 through 2023 for modeling purposes only. SoCalGas is not seeking to update the revenue requirements that were previously approved by the Commission in D.19-09-051.

[1] *See* SoCalGas Advice Letter 5536-G, approved January 3, 2020 and effective January 1, 2020.

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SOCALGAS

The table below summarizes the total revenue requirement with SoCalGas PTY ratemaking mechanism including Miscellaneous Revenues and Franchise Fees & Uncollectible ("FF&U").

Table 1

Line No.	Description ($ in millions)	PTY – 2020	PTY – 2021	PTY – 2022	PTY – 2023
1	Total O&M Margin (excluding FFU)	$1,380.1	$1,413.2	$1,450.7	$1,489.9
2	Capital Related Costs (Depreciation, Taxes, Return)	1,447.7	1,538.3	1,630.4	$1,722.2
3	PSEP Capital Related Costs	12.7	37.9	$63.8	$69.3
4	Total (L1 + L2 + L3)	2,840.5	2,989.5	$3,144.9	$3,281.4
5	FF&U	45.7	46.2	$46.9	$47.5
6	Total Base Margin (L4 + L5)	2,886.1	3,035.7	$3,191.8	$3,328.9
7	Miscellaneous Revenues	103.9	103.9	$103.9	$103.9
8	Total Revenue Requirement (L6 + L7)	2,990.0	3,139.6	3,295.7	3,432.8
9	Cost of Capital Adjustment	(3.7)	(4.0)	(4.4)	(4.6)
10	FF&U Adjustment	-	(0.4)	(1.1)	(1.2)
11	Adjusted Total Revenue Requirement (L8 + L9 + L10)	$2,986.3	$3,135.2	$3,290.2	$3,427.1
12	Revenue Requirement Increase $	$215.8	$148.9	$155.1	$136.8
13	Revenue Requirement Increase %	*7.79%*	*4.98%*	*4.95%*	*4.16%*

B. OPERATION & MAINTENANCE ("O&M") EXPENSES

The starting base for O&M escalation is the authorized 2021 revenue requirement excluding miscellaneous revenues, capital related margin, franchise fees, and uncollectibles (O&M Margin). After the PTY O&M expense is escalated, it will be grossed up for FF&U using the factors authorized in the TY 2019.

1. Escalation of O&M (including medical): For simplicity in calculating PTY escalation, a single weighted average gas O&M utility input price index ("GOMPI") is used to adjust O&M expenses to reflect the expected cost inflation of goods and services that SoCalGas will incur to serve its customers. The calculation of GOMPI is described in Mr. Scott Wilder's testimony (Exhibit 334) and also shown in the Update Testimony of SoCalGas and SDG&E (Exhibit 514). The escalation rates for 2022 and 2023 are outlined in the Declaration of Ryan Hom. The PTY O&M revenue requirement is calculated below (differences due to rounding) in Table 2:

Table 2

Line No.	O&M Expense Adjustment ($ in millions)	TY – 2019	PTY – 2020	PTY – 2021	PTY – 2022	PTY – 2023
1	Prior Year O&M Margin		$1,344.6	$1,380.1	$1,413.2	$1,450.7
2	O&M Escalation Rate		2.64%	2.40%	2.65%	2.71%
3	Attrition Year O&M Escalation (L1 * L2)		$35.5	$33.1	$37.5	$39.3
4	O&M Expense (L1 + L3)	$1,344.6	$1,380.1	$1,413.2	$1,450.7	$1,489.9

C. CAPITAL-RELATED

1. 7-Year Capital Additions Average

This section describes the development of PTY plant additions and other PTY rate base changes to determine the capital-related revenue requirement (authorized return, depreciation expense, tax, and franchise fee and uncollectible gross ups). The recorded (2013-2016) plant additions are taken from historically recorded rate base. The recorded (2016) and forecasted (2017-2019) rate base components, plant additions and plant retirements are from the testimony and workpapers of SoCalGas witness Mr. Patrick Moersen (Exhibits 376 and 377). Once each attrition year net plant additions are computed, incremental depreciation reserve, and deferred taxes are calculated in order to determine the rate base for each attrition year. The change in year over year rate base is then utilized to calculate the capital costs components of the revenue requirement.

Table 3

Line No.	Capital-Related Attrition ($ in millions)	TY – 2019	PTY – 2020	PTY – 2021	PTY – 2022	PTY – 2023
1	Prior Year Capital-Related Costs		$1,277.0	$1,447.7	$1,538.3	$1,630.4
2	Capital-Related Attrition		170.7	90.6	92.1	91.7
3	Capital-Related Costs (L1+ L2)	$1,277.0	$1,447.7	$1,538.3	$1,630.4	$1,722.2

The development of the PTY rate base and the derivation of individual revenue requirement components are described in detail below.

2. Rate Base: The starting point in developing rate base for each attrition year is the prior year plant in service. Weighted average ("WAVG") net plant additions for

the attrition year are added, and current year changes to the net depreciation and accumulated deferred tax reserve are made.

a) Weighted Net Plant Additions

1) The starting point used for the plant additions for the PTY is a seven-year average of plant additions. The seven-year average is comprised of four years of recorded (2013-2016, refer to Table-12, Line 7) and three years of forecasted (2017-2019 from the test year Results of Operations ("RO") model, see Table-14, Line 13) capital additions. Each year is escalated to test year dollars and then averaged (Table-5, Line 7-9). The seven-year average is then escalated to 2020, 2021,2022, and 2023 (Table-5, Line 10) using Global Insight indices, as described in the testimony of Scott Wilder (Exhibit 334) and Update Testimony of SoCalGas and SDG&E (Exhibit 514). The escalation rates for 2022 and 2023 are outlined in the Declaration of Ryan Hom (Attachment A in this Petition).

2) Plant retirements for the PTY are also calculated using a seven-year average of retirements. The seven-year average is comprised of four years of recorded (2013-2016, refer to Table-13, Line 7) and three years of forecasted (2017-2019) capital retirements from the Test Year RO model (Table-14, Line 14). Each year is escalated to test year dollars (Table-5, Lines 11-13) and then averaged. The resulting seven-year average is then escalated to 2020, 2021,2022, and 2023. (Table-5, Line 14) using Global Insight indices, as described in the testimony of Scott Wilder (Exhibit 334) and Update Testimony of SoCalGas and SDG&E (Exhibit 514). The escalation rates for 2022 and 2023 are outlined in the Declaration of Ryan Hom (Attachment A in this Petition)..

3) WAVG Net Plant Additions: Each PTY's WAVG net plant additions is calculated using the ratio of the prior year WAVG net plant additions balance to the prior year end of year ("EOY") net plant additions balance multiplied by the attrition-year's EOY net plant additions. (Table-5, Line 2)

   a. e.g. ($584,465 / $1,751,666) * $975,797 = $325,587

b) Change in Accumulated Depreciation Reserve: Each PTY's WAVG net depreciation reserve is calculated using the ratio of the attrition year WAVG plant in service balance to the prior year WAVG plant in service balance multiplied by the prior year's net depreciation reserve. Net depreciation reserve includes annual retirements, cost of removal and salvage. (Table-5, Line 5)

1) e.g. ($17,398,593 / $15,905,805) * $204,606= $223,808

c) Working Capital and Other: SoCalGas is not proposing to change the rate base elements of Materials and Supplies, Working Cash, Customer Advances for Construction, and deferred revenue from the Test Tear 2019 amounts. (Table 4, Line 4,5,7,8)

d) Repair Deductions Rate Base Adjustment (2016 – 2038) (Table-4, Line 9): SoCalGas proposes to continue the amortization of this rate base adjustment as ordered in D.16-06-054, page 192, and adjusted for Tax Cuts & Jobs Act ("TCJA") as discussed in the testimony and workpapers of witness Ragan Reeves (Exhibit 261 and 262).

e) Accumulated Deferred Taxes – 2017 Tax Cuts & Jobs Act Adj (Table-4, Line 11): SoCalGas calculated this rate base adjustment using the average rate assumption method ("ARAM") as explained by witness Ragan Reeves (Exhibit 261). SoCalGas proposes to continue the amortization of this adjustment into the PTYs.

f) Change in Accumulated Deferred Taxes – Plant: Each PTY's WAVG accumulated deferred taxes is calculated using the ratio of the test year level of deferred taxes to the test year WAVG plant in service. (Table-4, Line 13)

1) e.g. $750,352 / $15,905,805 * $17,398,593 = $820,773

g) Change in Accumulated Deferred Taxes – CIAC: Each PTY's WAVG accumulated deferred taxes is calculated using the ratio of the test year level of deferred taxes to the test year WAVG plant in service. (Table 4, Line 14)

1) e.g. (-$144,495 / $15,905,805) * $17,398,593 = -$158,056

The resulting Weighted Average Depreciated Rate Base and supporting calculations are shown in the tables below:

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SOCALGAS

Table 4

SOUTHERN CALIFORNIA GAS COMPANY
Weighted Average Depreciated Rate Base
(Thousands of Dollars)

Line No.	Account Description	2019 RO Model: Recorded Year 2016	Estimated Year 2017	Estimated Year 2018	Test Year 2019	2020-2023 Attrition Year: AY 2020	AY 2021	AY 2022	AY 2023
	Fixed Capital								
1	Plant In Service	12,560,245	13,395,415	14,599,337	15,905,805	17,398,593	18,379,540	19,374,787	20,386,009
2	Work-In-Progress (non-interest bearing)	507	558	605	625	625	625	625	625
3	Total Fixed Capital	12,560,752	13,395,973	14,599,941	15,906,431	17,399,218	18,380,166	19,375,412	20,386,634
	Working Capital								
4	Materials & Supplies	21,490	22,268	22,988	23,671	23,671	23,671	23,671	23,671
5	Working Cash	(341)	(353)	(365)	95,488	95,488	95,488	95,488	95,488
6	Total Working Capital	21,149	21,915	22,623	119,159	119,159	119,159	119,159	119,159
	Other								
7	Customer Advances For Construction	(97,909)	(95,539)	(96,209)	(96,879)	(96,879)	(96,879)	(96,879)	(96,879)
8	Deferred Revenue - ITCC	(38,640)	(38,038)	(36,462)	(33,664)	(33,664)	(33,664)	(33,664)	(33,664)
9	Repair Deductions Rate Base Adjustment (2016 - 2038)	(14,300)	(13,650)	(13,000)	(12,350)	(11,700)	(11,050)	(10,400)	(9,750)
10	Total Other	(150,848)	(147,227)	(145,670)	(142,892)	(142,242)	(141,592)	(140,942)	(140,292)
	Deductions For Reserves								
11	Accumulated Deferred Taxes - 2017 Tax Cuts & Jobs Act Adj			520,550	503,230	485,911	468,591	451,272	433,952
12	Accumulated Depreciation Reserve	6,788,175	7,089,107	7,450,074	7,856,806	8,295,823	8,767,656	9,265,565	9,789,947
13	Accumulated Deferred Taxes - Plant	1,186,177	1,248,928	793,820	750,352	820,773	867,049	914,000	961,704
14	Accumulated Deferred Taxes - CIAC	(124,794)	(135,689)	(140,886)	(144,495)	(158,056)	(166,968)	(176,009)	(185,195)
15	Accumulated Deferred Investment Tax Credits	0	0	0	0	0	0	0	0
16	Total Deductions For Reserves	7,849,558	8,202,346	8,623,557	8,965,892	9,444,451	9,936,329	10,454,827	11,000,408
17	Weighted Average Depreciated Rate Base	4,581,494	5,068,314	5,853,336	6,916,806	7,931,685	8,421,404	8,898,802	9,365,093

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SOCALGAS

Table 5

Line No.		2019 RO Model		2020-2023 Attrition Year Calc											
		2019		2020			2021			2022			2023		
	Plant In Service	End of Year	WAVG	End of Year	WAVG	WAVG Increase	End of Year	WAVG	WAVG Increase	End of Year	WAVG	WAVG Increase	End of Year	WAVG	WAVG Increase
1	Beginning of the Year	15,321,340	15,321,340	17,073,006	17,073,006	1,751,666	18,048,803	18,048,803	975,797	19,040,036	19,040,036	991,234	20,043,296	20,043,296	1,003,260
2	Net Additions	1,751,666	584,465	975,797	325,587	(258,878)	991,234	330,738	5,151	1,003,260	334,750	4,013	1,027,122	342,712	7,962
3	Total Fixed capital	17,073,006	15,905,805	18,048,803	17,398,593	1,492,787	19,040,036	18,379,540	980,948	20,043,296	19,374,787	995,246	21,070,419	20,386,009	1,011,222

Line No.		2019		2020			2021			2022			2023		
	Accum Depreciation	End of Year	WAVG	End of Year	WAVG	WAVG Increase	End of Year	WAVG	WAVG Increase	End of Year	WAVG	WAVG Increase	End of Year	WAVG	WAVG Increase
4	Beginning of the Year	7,652,200	7,652,200	8,072,015	8,072,015	419,815	8,531,230	8,531,230	459,215	9,016,335	9,016,335	485,106	9,527,710	9,527,710	511,374
5	Depreciation Reserve	419,815	204,606	459,215	223,808	19,203	485,106	236,427	12,619	511,374	249,229	12,802	538,064	262,237	13,008
6	Total	8,072,015	7,856,806	8,531,230	8,295,823	439,017	9,016,335	8,767,656	471,834	9,527,710	9,265,565	497,908	10,065,774	9,789,947	524,382

Line No.		Recorded				Forecast			PTY			
		2013 (2013$)	2014 (2014$)	2015 (2015$)	2016 (2016$)	2017 (2017$)	2018 (2018$)	2019 (2019$)	2020	2021	2022	2023
7	Capital Additions	582,977	496,049	766,383	752,748	1,360,330	1,196,044	1,861,864	Escalation Rate			
									1.93%	1.58%	1.21%	2.38%
8	Capital Additions (2016$)	579,407	487,669	764,153	752,748	1,291,246	1,098,050	1,645,469				
9	Capital Additions (2019$)	655,605	551,802	864,646	851,742	1,461,057	1,242,455	1,861,864				
10	Capital Additions 7-Year Average							1,069,882	1,090,485	1,107,737	1,121,176	1,147,843
11	Retirements	71,668	79,422	126,816	127,664	121,945	86,641	110,199				
12	Retirements (2016$)	71,229	78,081	126,447	127,664	115,752	79,543	97,391				
13	Retirements (2019$)	80,597	88,349	143,076	144,453	130,974	90,003	110,199				
14	Retirements 7-Year Average							112,522	114,688	116,503	117,916	120,721
15	Plant Additions for Ratebase								975,797	991,234	1,003,260	1,027,122

3. Revenue Requirement: The capital-related revenue requirement components for each attrition year are calculated using the methodologies described below:

   a) Depreciation Expense: Depreciation expense is calculated by multiplying the current PTY plant-in-service weighted average increase by the test year's system average depreciation rate. (Table-8, Lines 1-7)

   b) Ad Valorem Tax: Ad Valorem Tax is calculated by multiplying the current attrition year additions by the test year's system ad valorem tax rate. (Table-8, Lines 8-14)

   c) State Tax Depreciation: State Tax Depreciation income tax expense is calculated by multiplying the current attrition year additions by the test year's system average state tax depreciation rate and by the state income tax rate. (Table-10, Lines 10-18)

   d) Payroll Tax: Payroll Tax is calculated by multiplying the prior year payroll taxes by the current attrition year labor escalation rate forecasted by Global Insight. (Table-8, Lines 15-19)

   e) Federal Tax Depreciation: Federal Tax Depreciation income tax expense is calculated by multiplying current attrition year additions by the test year's system average federal tax depreciation rate and by the federal income tax rate. (Table-10, Lines 1-9)

   f) California Corporation Franchise Tax (Prior Year): Prior Year's state income tax is a deduction for federal income tax purposes. (Table-11, Lines 1-22)

g) Long-Term Debt Cost: Long-Term Debt Cost is calculated by multiplying the attrition year change in weighted average rate base by the authorized weighted cost of Long Term Debt. (Table-9, Lines 4-10)

h) Preferred Stock Cost: Preferred Stock Cost is calculated by multiplying the attrition year change in weighted average rate base by the authorized weighted return on Preferred Stock. (Table-9, Lines 11-17)

i) Common Equity Cost: Common Equity Cost is calculated by multiplying the attrition year change in weighted average rate base by the authorized weighted return on Common Equity. (Table-9, Lines 18-25)

j) Gross Ups: All revenue requirement components which are not directly deductible for income taxes are grossed up for income taxes. These are Book Depreciation, State Tax Depreciation, Federal Tax Depreciation, Preferred Stock Cost, Common Equity Cost, and California Corporation Franchise Tax (Prior Year). All revenue requirement components are grossed up for FF&U using the factors referenced in Section D.

4. Tax Law Changes: SoCalGas' revenue requirement will reflect all tax law changes (depreciation policy) and tax rate changes, including but not limited to changes in income taxes, payroll taxes, and ad valorem taxes.

D. ADJUSTMENTS TO O&M AND CAPITAL-RELATED

1. Cost of Capital Adjustment: Per D.19-12-056 (TY 2020 Cost of Capital), SoCalGas' authorized cost of debt decreased from 4.33% to 4.23%, resulted in a 0.0456% decrease in rate of return ("ROR"). As such, ROR has been adjusted to reflect this decrease as shown in Table 6 below.

Table 6

Line No.	Cost of Capital Adjustment	2020	2021	2022	2023
1	Weighted Avg Rate Base (w/o PSEP)	7,931,685	8,421,404	8,898,802	9,365,093
2	Weighted Avg Rate Base (PSEP only)	106,432	310,326	494,350	515,354
3	Total Weighted Avg Rate Base	8,038,117	8,731,729	9,393,152	9,880,447
4	Change in ROR *	(3,728)	(4,050)	(4,356)	(4,583)

* ROR is grossed up for FF&U

2. Franchise Fees and Uncollectible Gross Up: All revenue requirement components are grossed up for FF&U as calculated in the 2019 GRC RO Model. The calculation of the gross up factor is shown in Table 7 below:

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SOCALGAS

Table 7

Line No.	Description	2019	2020	2021	2022	2023
1	Revenues	1.000000	1.000000	1.000000	1.000000	1.000000
2	Uncollectible Tax Rate	0.003130	0.003130	0.003010	0.002780	0.002780
3	Uncollectible Amount Applied	1.000000	1.000000	1.000000	1.000000	1.000000
4	Less: Uncollectible (L2 * L3)	0.003130	0.003130	0.003010	0.002780	0.002780
5	Subtotal (L3 - L4)	0.996870	0.996870	0.996990	0.997220	0.997220
6	Franchise Fees Tax Rate	0.013720	0.013720	0.013720	0.013720	0.013720
7	Franchise Fees Amount Applied (L5)	0.996870	0.996870	0.996990	0.997220	0.997220
8	Less: Franchise Fees (L6 * L7)	0.013677	0.013677	0.013679	0.013682	0.013682
9	Subtotal (L7 - L8)	0.983193	0.983193	0.983311	0.983538	0.983538
10	Franchise Fee and Uncollectible Factor (1 / L9)	1.017094	1.017094	1.016972	1.016737	1.016737

The remaining capital-related tables are shown below.

Table 8

Southern California Gas Company
2019 GRC
Calculation of Revenue Requirement Increase
(Thousands of Dollars)

	Section-1					
Line	Depreciation Expense	2019	2020	2021	2022	2023
1	2019 Accrual	598,136				
2	/ 2019 Wtd Avg Plant in Service	15,905,805				
3	= System Average Depreciation Rate	3.76%	3.76%	3.76%	3.76%	3.76%
4	x Plant in Service Weighted Average Increase		1,492,787	980,948	995,246	1,011,222
5	= Increase in Depreciation Expense		56,136	36,888	37,426	38,027
6	x Net-to-Gross Multiplier	1.4123095	1.4123095	1.4123095	1.4123095	1.4123095
7	= Increase in Revenue Requirements		79,282	52,098	52,857	53,706
	Ad Valorem Taxes					
8	2019 Ad Valorem Taxes	77,451				
9	/ 2019 Plant in Service	17,073,006				
10	= System Average Ad Valorem Tax Rate	0.45%	0.45%	0.45%	0.45%	0.45%
11	x Current Attrition Year Additions		975,797	991,234	1,003,260	1,027,122
12	= Increase Full Year Additions		4,427	4,497	4,551	4,659
13	x Franchise Fee and Uncollectible Factor	1.0170944	1.0170944	1.0170944	1.0170944	1.0170944
14	= Increase in Revenue Requirements		4,502	4,574	4,629	4,739
	Payroll Taxes					
15	Prior Year Payroll Taxes		47,440	48,999	50,494	52,160
16	x Current Year Labor Escalation Rate		3.29%	3.05%	3.30%	3.25%
17	= Increase in Full Year Additions		1,560	1,494	1,667	1,694
18	x Franchise Fee and Uncollectible Factor		1.0170944	1.0170944	1.0170944	1.0170944
19	= Increase in Revenue Requirements		1,586	1,520	1,695	1,723

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SOCALGAS

Table 9

Southern California Gas Company
2019 GRC
Calculation of Revenue Requirement Increase
(Thousands of Dollars)

		Section-2				
Line	Change in Weighed Average Ratebase	2019	2020	2021	2022	2023
1	2019 Test Year Weighted Average Ratebase	6,916,806	6,916,806			
2	Weighed Average Ratebase		7,931,685	8,421,404	8,898,802	9,365,093
3	Change in Weighted Average Ratebase		1,014,879	489,719	477,398	466,291
	Long Term Debt					
4	Prior Year Return on Debt	4.33%	4.33%	4.33%	4.33%	4.33%
5	x Prior Year Debt Capitalization	45.60%	45.60%	45.60%	45.60%	45.60%
6	= Prior Year Weighted Cost of Debt	1.97%	1.97%	1.97%	1.97%	1.97%
7	x Change in Weighted Average Ratebase		1,014,879	489,719	477,398	466,291
8	= Change in Weighted Average Cost of Debt		20,039	9,669	9,426	9,207
9	x Franchise Fee and Uncollectible Factor		1.0170944	1.0170944	1.0170944	1.0170944
10	= Increase in Revenue Requirements		20,381	9,835	9,587	9,364
	Preferred Stock					
11	Prior Year Return on Preferred Stock	6.00%	6.00%	6.00%	6.00%	6.00%
12	x Prior Year Preferred Stock Capitalization	2.40%	2.40%	2.40%	2.40%	2.40%
13	= Prior Year Weighted Cost of Preferred Stock	0.14%	0.14%	0.14%	0.14%	0.14%
14	x Change in Weighted Average Ratebase		1,014,879	489,719	477,398	466,291
15	= Change in Weighted Cost of Preferred Stock		1,461	705	687	671
16	x Net-to-Gross Multiplier	1.4123095	1.4123095	1.4123095	1.4123095	1.4123095
17	= Increase in Revenue Requirements		2,064	996	971	948
	Common Equity					
18	Prior Return on Common Equity	10.05%	10.05%	10.05%	10.05%	10.05%
19	x Prior Year Common Equity Capitalization	52.00%	52.00%	52.00%	52.00%	52.00%
20	= Prior Year Weighted Cost of Common Equity	5.23%	5.23%	5.23%	5.23%	5.23%
21	x Change in Weighted Average Ratebase		1,014,879	489,719	477,398	466,291
22	= Change in Weighted Cost of Common Equity		53,038	25,593	24,949	24,368
23	x Net-to-Gross Multiplier	1.4123095	1.4123095	1.4123095	1.4123095	1.4123095
24	= Increase in Revenue Requirements		74,905	36,145	35,235	34,416
25	Total Increase in Revenue Requirements		97,351	46,975	45,794	44,728

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SOCALGAS

Table 10

Southern California Gas Company
2019 GRC
Calculation of Revenue Requirement Increase
(Thousands of Dollars)

		Section-3				
Line	Federal Tax Depreciation (ACRS/MACRS Basis)	2019	2020	2021	2022	2023
1	2019 Federal Tax Depreciation	428,715				
2	/ 2019 Plant in Service	17,073,006				
3	= System Average Federal Tax Depreciation Rate	2.51%	2.51%	2.51%	2.51%	2.51%
4	x Current Attrition Year Additions		975,797	991,234	1,003,260	1,027,122
5	= Increase in Federal Tax Depreciation Expense		24,503	24,891	25,193	25,792
6	x -Federal Income Tax Rate	(0.210)	(0.210)	(0.210)	(0.210)	(0.210)
7	= Federal Income Taxes		(5,146)	(5,227)	(5,290)	(5,416)
8	x Net-to-Gross Multiplier	1.4123095	1.4123095	1.4123095	1.4123095	1.4123095
9	= Increase in Revenue Requirements		(7,267)	(7,382)	(7,472)	(7,649)
	State Tax Depreciation					
10	2019 State Tax Depreciation	588,783				
11	/ 2019 Plant in Service	17,073,006				
12	= System Average State Tax Depreciation Rate	3.45%	3.45%	3.45%	3.45%	3.45%
13	x Current Attrition Year Additions		975,797	991,234	1,003,260	1,027,122
14	= Increase in State Tax Depreciation Expense		33,652	34,184	34,599	35,422
15	x -State Income Tax Rate		(0.0884)	(0.0884)	(0.0884)	(0.0884)
16	= State Income Taxes		(2,975)	(3,022)	(3,059)	(3,131)
17	x Net-to-Gross Multiplier	1.4123095	1.4123095	1.4123095	1.4123095	1.4123095
18	= Increase in Revenue Requirements		(4,201)	(4,268)	(4,320)	(4,422)

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SOCALGAS

Table 11

Southern California Gas Company
2019 GRC
Calculation of Revenue Requirement Increase
(Thousands of Dollars)

Line	Section-4 California Corporation Franchise Tax (Prior Year)	2020	2021	2022	2023
1	+ Depreciation		79,282	52,098	52,857
2	+ State Tax Depreciation		(4,201)	(4,268)	(4,320)
3	+ Federal Tax Depreciation (ACRS/MACRS)		(7,267)	(7,382)	(7,472)
4	+ Ratebase: Preferred Stock		2,064	996	971
5	+ Ratebase: Common Stock Equity		74,905	36,145	35,235
6	+ Financial Component: Preferred Stock		-	-	-
7	:Common Equity		-	-	-
8	+ CCFT		(540)	(2,899)	(1,062)
9	+ State & Federal Rate Changes		-	-	-
10	= Increase in Revenue Requirements		144,242	74,689	76,210
11	x Prior Year State Income Tax Cumulative Component		0.088400	0.088400	0.088400
12	= Prior Year State Income Tax Increase		12,751	6,603	6,737
13	+ Prior Year State Income Tax (State Tax Depreciation Expense)		(2,975)	(3,022)	(3,059)
14	+ Prior Year State Income Tax (State Rate Change)		-	-	-
15	= Prior Year Total State Income Taxes		9,776	3,581	3,678
16	Prior Year Current California Corp Franchise Tax	6,808	16,584	20,165	23,843
17	- Prior Year CCFT Deductible for Federal Income Taxes	4,987	6,808	16,584	20,165
18	= Increase CCFT Deduction on Federal Income Taxes	1,821	9,776	3,581	3,678
19	x -Federal Income Tax Rate	(0.2100)	(0.2100)	(0.2100)	(0.2100)
20	= Federal Income Taxes	(382)	(2,053)	(752)	(772)
21	x Net-to-Gross Multiplier	1.4123095	1.4123095	1.4123095	1.4123095
22	= Increase in Revenue Requirements	(540)	(2,899)	(1,062)	(1,091)

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SOCALGAS

Table 12

Line No.	Description ($ in dollars)	2013 Adjusted Recorded Additions	2014 Adjusted Recorded Additions	2015 Adjusted Recorded Additions	2016 Adjusted Recorded Additions
1	Intangible	5,718	5,261	0	0
2	Storage	32,461,877	36,417,901	133,676,696	89,966,359
3	Transmission	105,867,039	67,096,836	102,469,928	82,628,733
4	Distribution	246,899,120	307,159,114	348,902,169	426,062,987
5	General Plant	197,004,643	83,434,006	180,396,910	154,089,845
6	Cushion Gas Purchases	738,372	1,936,291	937,167	0
7	Total Additions (L1 + L2 + L3 + L4 + L5 + L6)	582,976,769	496,049,409	766,382,870	752,747,924

Note: This table excludes SECCBA, Native Gas Production, AMI, and Aliso leak costs.

Table 13

Line No.	Description ($ in dollars)	2013 Adjusted Recorded Retirements	2014 Adjusted Recorded Retirements	2015 Adjusted Recorded Retirements	2016 Adjusted Recorded Retirements
1	Intangible	0	0	0	0
2	Storage	5,987,647	4,261,709	7,161,105	14,944,464
3	Transmission	1,741,030	3,808,455	5,025,441	10,024,057
4	Distribution	29,606,085	25,445,905	50,269,767	54,529,434
5	General Plant	34,333,288	45,906,338	64,359,822	48,165,721
6	Cushion Gas Purchases	0	0	0	0
7	Total Retirements (L1 + L2 + L3 + L4 + L5 + L6)	71,668,050	79,422,407	126,816,135	127,663,676

Note: This table excludes PSEP and Native Gas Production which are not part of the TY2019 GRC scope.

PROPOSED POST-TEST YEAR RATEMAKING MECHANISM
SOCALGAS

Table 14

Southern California Gas Company
Calculation of Monthly CWIP, Plant and Accumulated Depreciation Balances
(Thousands of Dollars)

Asset Type: Total Utility Plant

Line No.		2017	2018	2019
1	Beg Month CWIP Balance	605,070	433,459	608,059
2	Expenditures	1,125,072	1,316,423	1,688,403
3	Expenditures - AFUDC	63,647	54,221	70,540
4	Total Expenditures	1,188,719	1,370,644	1,758,944
5	Additions	1,302,257	1,151,583	1,784,353
6	Additions - AFUDC	58,073	44,461	77,511
7	Total Additions	1,360,330	1,196,044	1,861,864
8	End Month CWIP	433,459	608,059	505,139
9	Interest Bearing CWIP	432,941	607,370	504,579
10	Non-interest Bearing CWIP	518	689	560
11	End Month CWIP	433,459	608,059	505,139
12	Beg Month Plant Balance	12,972,482	14,211,937	15,321,340
13	Additions	1,360,330	1,196,044	1,861,864
14	Retirements	121,945	86,641	110,199
15	Transfers	1,070	0	0
16	End Month Plant Balance	14,211,937	15,321,340	17,073,006
17	Depreciation Accrual Accrual Monthly Rate	495,064	538,431	598,136
18	Beg Month Reserve Balance	6,928,247	7,254,355	7,652,200
19	Provision	495,064	538,431	598,136
20	Retirements	121,945	86,641	110,199
21	Salvage	1,712	1,835	1,847
22	Removal Costs	48,738	55,780	69,969
23	Transfers	14	0	0
24	End Month Reserve Balance	7,254,355	7,652,200	8,072,015

E. PSEP CAPITAL-RELATED

Please see Attachment C.2 of this Petition for the workpapers in support of the PSEP capital-related revenue requirements calculations (SCG-PFM PSEP-1 to SCG-PFM PSEP-11).

ATTACHMENT C.2

SOCALGAS PSEP WORKPAPERS TO DECLARATION OF JESSE S. ARAGON ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY

WORKPAPER TITLE
Direct Costs
WITNESS
Jesse S. Aragon

(2016 $ in Thousands of Dollars)

Line No.		Phase	In Service Date	Total	Prior to 2017 [1]	2017	2018	2019	2020	2021	2022
	FERC 376 Distribution Mains										
1	36-9-09 North Section 14	Phase 1B	Jan-20	$18,331	$735	$0	$0	$13,748	$3,848	$0	$0
2	36-9-09 North Section 15	Phase 1B	May-20	$13,022	$694	$0	$0	$0	$12,328	$0	$0
3	36-9-09 North Section 16	Phase 1B	Aug-20	$16,575	$726	$0	$0	$0	$15,849	$0	$0
4	36-1032 Section 11	Phase 1B	Sep-20	$7,962	$443	$0	$0	$0	$7,519	$0	$0
5	PSEP PMO		Dec-20	$3,129	$0	$0	$0	$0	$3,129	$0	$0
6	Valve Enhancement Plan	Phase 1B	Jun-20	$6,797	$0	$0	$544	$544	$5,709	$0	$0
7	36-1032 Section 12	Phase 1B	Feb-21	$24,374	$515	$0	$0	$0	$0	$23,859	$0
8	36-1032 Section 13	Phase 1B	Jul-21	$16,385	$457	$0	$0	$0	$0	$15,928	$0
9	36-1032 Section 14	Phase 1B	Nov-21	$12,778	$439	$0	$0	$0	$0	$12,339	$0
10	44-1008	Phase 1B	Jul-21, Jul-22	$36	$36	$0	$0	$0	$0	$0	$0
11	PSEP PMO		Dec-21	$3,129	$0	$0	$0	$0	$0	$3,129	$0
12	Valve Enhancement Plan	Phase 1B	Jun-21	$6,797	$0	$0	$0	$544	$544	$5,709	$0
13	Fourth Year PSEP PMO		Dec-22	$3,091	$0	$0	$0	$0	$0	$0	$3,091
14	**Subtotal FERC 376 (L1 + L2 + … + L13)**			**$132,405**	**$4,046**	**$0**	**$544**	**$14,836**	**$48,925**	**$60,964**	**$3,091**
	FERC 367 Transmission Mains										
15	407	Phase 2A	Oct-20	$861	$0	$11	$0	$0	$850	$0	$0
16	235 West Section 2	Phase 2A	Dec-20	$0	$0	$0	$0	$0	$0	$0	$0
17	235 West Section 3	Phase 2A	Jun-20	$3,076	$0	$13	$0	$1,025	$2,038	$0	$0
18	2000 Section E	Phase 2A	Dec-20	$1,437	$0	$24	$36	$0	$1,378	$0	$0
19	2000-E Cactus City Compressor Station	Phase 2A	Dec-20	$6,131	$0	$0	$0	$0	$6,131	$0	$0
20	2000 Blythe to Cactus City Hydrotest	Phase 2A	Dec-20	$10,919	$0	$73	$0	$0	$10,846	$0	$0
21	PSEP PMO		Dec-20	$6,073	$0	$0	$0	$0	$6,073	$0	$0
22	Allowance for Pipeline Failure	Phase 2A	Jun-20	$2,057	$0	$0	$0	$0	$2,057	$0	$0
23	Valve Enhancement Plan	Phase 1B	Jun-20	$68,722	$0	$0	$5,498	$5,498	$57,726	$0	$0
24	235 West Section 1	Phase 2A	Dec-21	$0	$15	$0	$0	$0	$0	($15)	$0
25	2001 W Section E	Phase 2A	Jun-21	$2,712	$0	$49	$0	$0	$0	$2,663	$0
26	2001 W Section D	Phase 2A	Sep-21	$4,393	$0	$89	$0	$0	$0	$4,304	$0
27	2001 W Section C	Phase 2A	Dec-21	$3,058	$0	$48	$0	$0	$0	$3,010	$0
28	2000 Chino Hills	Phase 2A	Dec-21	$10,483	$0	$3	$0	$0	$0	$10,480	$0
29	1011	Phase 2A	Jul-21	$666	$0	$12	$0	$0	$0	$654	$0
30	85 Elk Hills to Lake Station	Phase 1B	Dec-21	$81,687	$3,404	$1,266	$2,630	$6,592	$11,912	$55,883	$0
31	PSEP PMO		Dec-21	$6,073	$0	$0	$0	$0	$0	$6,073	$0
32	Allowance for Pipeline Failures	Phase 2A	Jun-21	$2,057	$0	$0	$0	$0	$0	$2,057	$0
33	Valve Enhancement Plan	Phase 1B	Jun-21	$68,722	$0	$0	$0	$5,498	$5,498	$57,726	$0
34	225 North	Phase 2A	Dec-22	$4,482	$0	$112	$0	$83	$83	$83	$4,122
35	1030	Phase 2A	Dec-22	$7,393	$0	$45	$0	$186	$186	$186	$6,791
36	5000	Phase 2A	Dec-22	$4,172	$0	$89	$0	$6	$6	$6	$4,064
37	2005	Phase 2A	Dec-22	$852	$0	$39	$0	$27	$27	$27	$733
38	2001E	Phase 2A	Sep-22	$7,753	$0	$37	$0	$173	$173	$173	$7,196
39	2001 East Replacement	Phase 2A	Sep-22	$3,517	$0	$80	$0	$6	$6	$6	$3,420
40	2001 West	Phase 2A	Sep-22	$1,572	$0	$38	$0	$89	$89	$89	$1,267
41	Fourth Year PSEP PMO		Dec-22	$6,001	$0	$0	$0	$0	$0	$0	$6,001
42	**Subtotal FERC 367 (L15 +L16 + … + L41)**			**$314,868**	**$3,419**	**$2,026**	**$8,163**	**$19,182**	**$105,077**	**$143,405**	**$33,595**
43	**Total Capital (L14 + L42)**			**$447,274**	**$7,465**	**$2,026**	**$8,707**	**$34,018**	**$154,002**	**$204,369**	**$36,686**

[1] Prior to 2017 represents actual costs recorded in prior period
*Numbers may not add due to rounding.

WORKPAPER TITLE
Annual Escalation Rates and Factors
WITNESS
Jesse S. Aragon

Line No.	Cost Category		% Change 2016	2017	2018	2019	2020	2021	2022
1	Gas Distribution - Capital	Gas Distribution Plant	0.00%	5.35%	3.39%	3.88%	1.93%	1.58%	1.21%
2	Gas Transmission - Capital	Gas Transmission Plant	0.00%	5.35%	3.39%	3.88%	1.93%	1.58%	1.21%

Line No.	Cost Category		Escalation Factor (2016 Base) 2016	2017	2018	2019	2020	2021	2022
3	Gas Distribution - Capital	Gas Distribution Plant	100.00%	105.35%	108.92%	113.15%	115.33%	117.15%	119.29%
4	Gas Transmission - Capital	Gas Transmission Plant	100.00%	105.35%	108.92%	113.15%	115.33%	117.15%	119.29%

Line No.	Cost Category		Escalation Factor 2016	2017	2018	2019	2020	2021	2022
5	Gas Distribution - Capital	Gas Distribution Plant	0.00%	5.35%	8.92%	13.15%	15.33%	17.15%	19.29%
6	Gas Transmission - Capital	Gas Transmission Plant	0.00%	5.35%	8.92%	13.15%	15.33%	17.15%	19.29%

Factors through 2021 are from escalation indices published in the IHS Global Insight 2nd Quarter 2018 Utility Cost Forecast, which D.19-09-051 is based on.
Per D.20-01-002, factors for 2022 are updated based on Global Insight 4th Quarter 2019 Utility Cost Forecast.

WORKPAPER TITLE Overhead Factor
WITNESS Jesse S. Aragon

Line No.		2017	2018	2019	2020 [1]	2021 [1]	2022 [1]
1	Composite Overhead Factor (%)	12.30%	9.46%	7.12%	9.63%	9.63%	9.63%

Factors shown above are from the 2019 GRC RO model

[1] Composite overhead factor (%) was derived by averaging the 2017 through 2019 composite overhead factor (%)

WORKPAPER TITLE
Cost of Removal Factor
WITNESS
Jesse S. Aragon

Line No.	Asset ID	Description	Cost of Removal Percentage
1	70	Trans - Depreciable	-6.12%
2	100	Dist - Depreciable	-3.23%

Factors shown above are from the 2019 GRC RO model

WORKPAPER TITLE
Fully Loaded and Escalated Costs

WITNESS
Jesse S. Aragon

($ in Thousands of Dollars)

Line No.		Total	Prior to 2017 [1]	2017	2018	2019	2020	2021	2022
	FERC 376 Distribution Mains								
1	Total Direct Capital (WP PSEP-1, L14)	$132,405	$4,046	$0	$544	$14,836	$48,925	$60,964	$3,091
2	Escalation Impact (L1 * WP PSEP-2, L5)	$20,554	$0	$0	$49	$1,951	$7,500	$10,458	$596
	Actual Overhead								
3	Overhead ((L1 + L2) * WP PSEP-3, L1) (1)	$14,153	$241	$0	$56	$1,195	$5,431	$6,875	$355
4	Cost of Removal ((L1 + L2+ L3) * WP PSEP-4, L1)	($5,261)	$0	$0	($21)	($581)	($1,998)	($2,530)	($131)
5	Total Capital (Loaded & Escalated, less Cost of Removal) (L1 + L2 + L3 + L4)	$161,852	$4,286	$0	$627	$17,401	$59,858	$75,767	$3,912
6	Capital - Property Tax	$628	$7	$44	$52	$142	$210	$173	$0
7	Capital - AFUDC	$4,643	$53	$362	$385	$1,096	$1,473	$1,274	$0
8	**Subtotal FERC 376 (L5 + L6 + L7)**	$167,123	$4,347	$407	$1,064	$18,638	$61,541	$77,214	$3,912
	FERC 367 Transmission Mains								
9	Total Direct Capital (WP PSEP-1, L42)	$314,868	$3,419	$2,026	$8,163	$19,182	$105,077	$143,405	$33,595
10	Escalation Impact (L9 * WP PSEP-2, L6)	$50,549	$0	$108	$729	$2,523	$16,108	$24,600	$6,481
11	Overhead ((L9 + L10) * WP PSEP-3, L1)	$34,911	$567	$263	$841	$1,545	$11,665	$16,172	$3,858
12	Cost of Removal ((L9 + L10+ L11) * WP PSEP-4, L2)	($24,276)	$0	($147)	($596)	($1,424)	($8,137)	($11,281)	($2,691)
13	Total Capital (Loaded & Escalated, less Cost of Removal) (L9 + L10 + L11 + L12)	$376,052	$3,987	$2,250	$9,137	$21,826	$124,714	$172,897	$41,242
14	Capital - Property Tax	$2,049	$7	$49	$107	$268	$716	$901	$0
15	Capital - AFUDC	$15,428	$53	$410	$820	$2,038	$5,272	$6,835	$0
16	**Subtotal FERC 367 (L13 + L14 + L15)**	$393,529	$4,047	$2,710	$10,063	$24,132	$130,702	$180,633	$41,242
17	**Total Capital (L8 + L16)**	**$560,653**	**$8,394**	**$3,116**	**$11,128**	**$42,771**	**$192,243**	**$257,848**	**$45,154**

[1] Prior to 2017 represents actual costs recorded in prior period
Numbers may not add due to rounding.

Southern California Gas Company
2019 GRC Post Test Year PSEP Capital Related Costs
Revenue Requirement Summary ($ in Thousands of Dollars)

	Total	2017	2018	2019	2020	2021	2022	2023
Revenue Requirement - Total	183,777	-	-	-	12,720	37,944	63,829	69,285
FF&U:	3,089	-	-	-	214	638	1,073	1,164
O&M:	-	-	-	-	-	-	-	-
Working Capital:	-	-	-	-	-	-	-	-
Depreciation:	39,715	-	-	-	2,848	8,426	13,680	14,761
Return on Common:	74,547	-	-	-	5,562	16,218	25,835	26,932
Return on Preferred:	2,054	-	-	-	153	447	712	742
Return On Debt:	28,165	-	-	-	2,101	6,127	9,761	10,176
Federal Taxes:	20,972	-	-	-	1,605	4,493	7,312	7,562
State Taxes:	2,468	-	-	-	236	249	818	1,166
Property Taxes:	12,766	-	-	-	-	1,346	4,639	6,781

	Total	2017	2018	2019	2020	2021	2022	2023
Revenue Requirement - Distribution	63,783	-	-	-	6,287	15,952	20,559	20,985
FF&U:	1,072	-	-	-	106	268	346	353
O&M:	-	-	-	-	-	-	-	-
Working Capital:	-	-	-	-	-	-	-	-
Depreciation:	13,915	-	-	-	1,397	3,518	4,449	4,551
Return on Common:	25,219	-	-	-	2,652	6,559	8,060	7,947
Return on Preferred:	695	-	-	-	73	181	222	219
Return On Debt:	9,528	-	-	-	1,002	2,478	3,045	3,003
Federal Taxes:	7,138	-	-	-	803	1,883	2,248	2,204
State Taxes:	2,026	-	-	-	254	525	607	639
Property Taxes:	4,190	-	-	-	-	540	1,581	2,070

	Total	2017	2018	2019	2020	2021	2022	2023
Revenue Requirement - Transmission	119,994	-	-	-	6,433	21,992	43,270	48,300
FF&U:	2,017	-	-	-	108	370	727	812
O&M:	-	-	-	-	-	-	-	-
Working Capital:	-	-	-	-	-	-	-	-
Depreciation:	25,800	-	-	-	1,451	4,908	9,230	10,211
Return on Common:	49,328	-	-	-	2,910	9,658	17,774	18,985
Return on Preferred:	1,359	-	-	-	80	266	490	523
Return On Debt:	18,637	-	-	-	1,100	3,649	6,715	7,173
Federal Taxes:	13,834	-	-	-	802	2,610	5,064	5,358
State Taxes:	442	-	-	-	(18)	(276)	210	526
Property Taxes:	8,576	-	-	-	-	807	3,058	4,712

Southern California Gas Company

2019 GRC Post Test Year PSEP Capital Related Costs

FF&U Summary ($ in Thousands of Dollars)

	Total	2017	2018	2019	2020	2021	2022	2023
O&M	-	-	-	-	-	-	-	-
Working Capital	-	-	-	-	-	-	-	-
Depreciation	39,715	-	-	-	2,848	8,426	13,680	14,761
Return on Common	74,547	-	-	-	5,562	16,218	25,835	26,932
Return on Preferred	2,054	-	-	-	153	447	712	742
Return On Debt	28,165	-	-	-	2,101	6,127	9,761	10,176
Federal Taxes	20,972	-	-	-	1,605	4,493	7,312	7,562
State Taxes	2,468	-	-	-	236	249	818	1,166
Property Taxes	12,766	-	-	-	-	1,346	4,639	6,781
Sum	180,688	-	-	-	12,506	37,306	62,756	68,120
FF&U Rate		-	-	-	1.71%	1.71%	1.71%	1.71%
FF&U	3,089	-	-	-	214	638	1,073	1,164

Southern California Gas Company

2019 GRC Post Test Year PSEP Capital Related Costs

Rate Base and Return ($ in Thousands of Dollars)

	Total	2017	2018	2019	2020	2021	2022	2023
Average Monthly Rate Base		-	-	-	106,432	310,326	494,350	515,354
Return on Equity ($)	74,547	-	-	-	5,562	16,218	25,835	26,932
Weighted Return on Equity (%)		-	-	-	5.23%	5.23%	5.23%	5.23%
Return on Preferred ($)	2,054	-	-	-	153	447	712	742
Weighted Return on Preferred (%)		-	-	-	0.14%	0.14%	0.14%	0.14%
Return on Debt ($)	28,165	-	-	-	2,101	6,127	9,761	10,176
Weighted Return on Debt (%)		-	-	-	1.97%	1.97%	1.97%	1.97%
Total Return	104,766	-	-	-	7,817	22,792	36,307	37,850
Total Rate of Return		-	-	-	7.34%	7.34%	7.34%	7.34%

Southern California Gas Company

2019 GRC Post Test Year PSEP Capital Related Costs

Property Taxes ($ in Thousands of Dollars)

-

	Total	2016	2017	2018	2019	2020	2021	2022	2023
Average of Month-End Rate Base		-	-	-	-	106,259	309,775	493,508	514,491
Property Tax Rate	0.67%	-	-	-	-	0.00%	0.43%	0.94%	1.32%
Property Tax	12,766	-	-	-	-	-	1,346	4,639	6,781

Southern California Gas Company

2019 GRC Post Test Year PSEP Capital Related Costs

Income Taxes ($ in Thousands of Dollars)

	Total	2017	2018	2019	2020	2021	2022	2023
Revenue	183,777	-	-	-	12,720	37,944	63,829	69,285
Operational Costs	(55,570)	-	-	-	(3,062)	(10,410)	(19,391)	(22,707)
EBIT	128,206	-	-	-	9,658	27,534	44,437	46,578
Income Taxes	(23,440)	-	-	-	(1,841)	(4,742)	(8,130)	(8,728)
NOI	104,766	-	-	-	7,817	22,792	36,307	37,850
Interest	(28,165)	-	-	-	(2,101)	(6,127)	(9,761)	(10,176)
Interest During Construction	(21,484)	(772)	(1,205)	(3,134)	(6,744)	(8,109)	(1,519)	-
Preferred Dividends	(2,054)	-	-	-	(153)	(447)	(712)	(742)
Earnings for Common	53,063	(772)	(1,205)	(3,134)	(1,182)	8,109	24,316	26,932

FIT Detail	**Total**	2017	2018	2019	2020	2021	2022	2023
EBIT	128,206	-	-	-	9,658	27,534	44,437	46,578
Difference in Depreciation	1,130	-	-	-	85	226	393	426
State Taxes (Prior Period)	1,303	-	-	-	-	236	250	818
Salvage	-	-	-	-	-	-	-	-
Interest	28,165	-	-	-	2,101	6,127	9,761	10,176
Total Federal EBT Adjustments	(28,339)	-	-	-	(2,016)	(6,137)	(9,617)	(10,568)
Federal EBT	99,867	-	-	-	7,641	21,396	34,820	36,010
Federal Tax Rate		-	-	-	21.0%	21.0%	21.0%	21.0%
FIT	20,972	-	-	-	1,605	4,493	7,312	7,562

SIT Detail	**Total**	2017	2018	2019	2020	2021	2022	2023
EBIT	128,206	-	-	-	9,658	27,534	44,437	46,578
Difference in Depreciation	(72,122)	-	-	-	(4,886)	(18,593)	(25,426)	(23,218)
Salvage	-	-	-	-	-	-	-	-
Interest	28,165	-	-	-	2,101	6,127	9,761	10,176
Total State EBT Adjustments	(100,288)	-	-	-	(6,988)	(24,720)	(35,187)	(33,393)
State EBT	27,919	-	-	-	2,670	2,814	9,250	13,184
State Tax Rate		-	-	-	8.84%	8.84%	8.84%	8.84%
SIT	2,468	-	-	-	236	249	818	1,166

Southern California Gas Company

2019 GRC Post Test Year PSEP Capital Related Costs

Rate Base Detail ($ in Thousands of Dollars)

		2016	2017	2018	2019	2020	2021	2022	2023
January	Historical Costs		-	-	-	23,045	206,964	513,303	563,307
	Accumulated Depreciation		-	-	-	(52)	(3,303)	(12,402)	(26,190)
	Deferred Taxes Impacting Rate Base		-	-	-	(4)	(1,517)	(6,614)	(13,138)
	Month End Rate Base		-	-	-	22,989	202,144	494,287	523,979
	New Investment		-	-	-	23,045	-	-	-
	Average Monthly Rate Base		**-**	**-**	**-**	**23,017**	**202,475**	**495,102**	**524,842**
February	Historical Costs		-	-	-	23,045	237,333	513,303	563,307
	Accumulated Depreciation		-	-	-	(104)	(3,826)	(13,524)	(27,420)
	Deferred Taxes Impacting Rate Base		-	-	-	(8)	(1,732)	(7,121)	(13,633)
	Month End Rate Base		-	-	-	22,933	231,775	492,658	522,254
	New Investment		-	-	-	-	30,369	-	-
	Average Monthly Rate Base		**-**	**-**	**-**	**22,961**	**232,144**	**493,473**	**523,117**
March	Historical Costs		-	-	-	23,045	237,333	513,303	563,307
	Accumulated Depreciation		-	-	-	(157)	(4,350)	(14,646)	(28,650)
	Deferred Taxes Impacting Rate Base		-	-	-	(12)	(1,947)	(7,627)	(14,128)
	Month End Rate Base		-	-	-	22,876	231,036	491,029	520,529
	New Investment		-	-	-	-	-	-	-
	Average Monthly Rate Base		**-**	**-**	**-**	**22,905**	**231,405**	**491,844**	**521,392**
April	Historical Costs		-	-	-	23,045	237,333	513,303	563,307
	Accumulated Depreciation		-	-	-	(209)	(4,873)	(15,768)	(29,880)
	Deferred Taxes Impacting Rate Base		-	-	-	(16)	(2,163)	(8,134)	(14,623)
	Month End Rate Base		-	-	-	22,820	230,297	489,400	518,804
	New Investment		-	-	-	-	-	-	-
	Average Monthly Rate Base		**-**	**-**	**-**	**22,848**	**230,667**	**490,215**	**519,667**
May	Historical Costs		-	-	-	39,374	237,333	513,303	563,307
	Accumulated Depreciation		-	-	-	(298)	(5,396)	(16,891)	(31,110)
	Deferred Taxes Impacting Rate Base		-	-	-	(28)	(2,378)	(8,641)	(15,118)
	Month End Rate Base		-	-	-	39,048	229,559	487,771	517,079
	New Investment		-	-	-	16,329	-	-	-
	Average Monthly Rate Base		**-**	**-**	**-**	**39,099**	**229,928**	**488,586**	**517,941**
June	Historical Costs		-	-	-	139,507	337,645	513,303	563,307
	Accumulated Depreciation		-	-	-	(604)	(6,136)	(18,013)	(32,340)
	Deferred Taxes Impacting Rate Base		-	-	-	(138)	(2,692)	(9,148)	(15,613)
	Month End Rate Base		-	-	-	138,765	328,817	486,142	515,354
	New Investment		-	-	-	100,133	100,312	-	-
	Average Monthly Rate Base		**-**	**-**	**-**	**138,973**	**329,344**	**486,957**	**516,216**
July	Historical Costs		-	-	-	139,507	359,233	513,303	563,307
	Accumulated Depreciation		-	-	-	(909)	(6,925)	(19,135)	(33,570)
	Deferred Taxes Impacting Rate Base		-	-	-	(249)	(3,025)	(9,655)	(16,108)
	Month End Rate Base		-	-	-	138,349	349,284	484,514	513,629
	New Investment		-	-	-	-	21,588	-	-
	Average Monthly Rate Base		**-**	**-**	**-**	**138,557**	**349,844**	**485,328**	**514,491**
August	Historical Costs		-	-	-	160,440	359,233	513,303	563,307
	Accumulated Depreciation		-	-	-	(1,262)	(7,714)	(20,257)	(34,800)
	Deferred Taxes Impacting Rate Base		-	-	-	(381)	(3,357)	(10,161)	(16,603)
	Month End Rate Base		-	-	-	158,796	348,163	482,885	511,904
	New Investment		-	-	-	20,933	-	-	-
	Average Monthly Rate Base		**-**	**-**	**-**	**159,039**	**348,723**	**483,699**	**512,766**
September	Historical Costs		-	-	-	170,543	364,795	529,716	563,307
	Accumulated Depreciation		-	-	-	(1,638)	(8,514)	(21,415)	(36,030)
	Deferred Taxes Impacting Rate Base		-	-	-	(529)	(3,701)	(10,703)	(17,098)
	Month End Rate Base		-	-	-	168,376	352,580	497,598	510,179
	New Investment		-	-	-	10,103	5,562	16,413	-
	Average Monthly Rate Base		**-**	**-**	**-**	**168,638**	**353,152**	**498,448**	**511,041**
October	Historical Costs		-	-	-	171,632	364,795	529,716	563,307
	Accumulated Depreciation		-	-	-	(2,016)	(9,315)	(22,572)	(37,260)
	Deferred Taxes Impacting Rate Base		-	-	-	(679)	(4,045)	(11,244)	(17,593)
	Month End Rate Base		-	-	-	168,937	351,435	495,899	508,454
	New Investment		-	-	-	1,090	-	-	-
	Average Monthly Rate Base		**-**	**-**	**-**	**169,202**	**352,007**	**496,749**	**509,316**
November	Historical Costs		-	-	-	171,632	381,185	529,716	563,307
	Accumulated Depreciation		-	-	-	(2,394)	(10,153)	(23,729)	(38,490)
	Deferred Taxes Impacting Rate Base		-	-	-	(830)	(4,444)	(11,786)	(18,087)
	Month End Rate Base		-	-	-	168,409	366,588	494,201	506,729
	New Investment		-	-	-	-	16,390	-	-
	Average Monthly Rate Base		**-**	**-**	**-**	**168,673**	**367,206**	**495,050**	**507,591**
December	Historical Costs	-	-	-	-	206,964	513,001	563,307	563,307
	Accumulated Depreciation	-	-	-	-	(2,848)	(11,274)	(24,960)	(39,721)
	Deferred Taxes Impacting Rate Base	-	-	-	-	(1,309)	(6,106)	(12,643)	(18,582)
	Year End Rate Base	-	-	-	-	202,807	495,621	525,704	505,003
	New Investment	-	-	-	-	35,332	131,816	33,591	-
	Average Monthly Rate Base		**-**	**-**	**-**	**203,273**	**497,012**	**526,748**	**505,866**
Average of Month-End Rate Base		**-**	**-**	**-**	**-**	**106,259**	**309,775**	**493,508**	**514,491**
Average Monthly Rate Base		**-**	**-**	**-**	**-**	**106,432**	**310,326**	**494,350**	**515,354**

ATTACHMENT D

DEANA NG DECLARATION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U 902 M) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019.	Application No. 17-10-007 (Filed October 6, 2017)
And Related Matter.	Application No. 17-10-008 (Filed October 6, 2017)

DECLARATION OF DEANA M. NG ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY AND SAN DIEGO GAS & ELECTRIC COMPANY IN SUPPORT OF PETITION FOR MODIFICATION OF D.19-09-051

I, Deana M. Ng, declare that:

1. I am currently employed by Southern California Gas Company ("SoCalGas") as Director of the Program Management Office ("PMO"). My current responsibilities include providing independent, consistent and timely oversight and reporting of the health and successful delivery of the natural gas infrastructure construction portfolio, with particular focus on governance, financial performance, process assurance, data analytics and reporting, training and development, resource planning, and regulatory compliance.

2. I have reviewed the Petition for Modification ("Petition") of Decision ("D.") D.19-09-051, the Decision Addressing the Test Year ("TY") 2019 General Rate Cases ("GRCs") of San Diego Gas & Electric Company ("SDG&E") and SoCalGas, approved on September 26, 2019 (hereinafter referred to as the "2019 GRC Decision"). The purpose of my declaration is to provide factual support for SoCalGas' proposal for additional attrition years (2022 and 2023), specifically for the PSEP component.

3. As described in the Petition, the Commission's recent decision (D.20-01-002, hereinafter referred to as the "RCP Decision") in Rulemaking ("R.") 13-11-006 (the "Rate Case

Plan" or "RCP" Rulemaking) extends the GRC cycle for each large California investor-owned utility ("IOU") from three to four years. To implement this transition, the Commission directed SoCalGas and SDG&E to file a petition for modification of D.19-09-051 "as soon as practicable" to request the addition of 2022 and 2023 as attrition years to the current GRC cycle and to include "anticipated … [PSEP] and other capital projects for 2022 and 2023."[1]

4. To address the requirements of the RCP Decision related to PSEP, in this declaration, SoCalGas proposes to 1) apply the PSEP methodology authorized in the 2019 GRC Decision to the 2022 project forecasts presented in its 2019 GRC Application to support development of a 2022 PSEP capital revenue requirement, and 2) rely on the projects presented in the 2019 GRC record as the basis for the 2023 revenue requirement and not forecast additional PSEP projects for 2023. Each is discussed further below. The revenue requirements for 2022 and 2023 resulting from these PSEP proposals are provided in the declaration of Jesse Aragon (Petition Attachment C).

The Commission Authorized a Test Year Revenue Requirement and a Post-Test Year Mechanism Associated with SoCalGas' PSEP Projects for 2019 - 2021.

5. In the 2019 GRC Application, SoCalGas presented detailed estimates to complete eleven PSEP pressure test projects, eleven PSEP replacement projects, and 284 PSEP valve projects. SoCalGas characterized the PSEP projects included in the 2019 GRC Application as those "expected" to be completed in the three-year (2019-2021) GRC cycle[2] and requested recovery of the associated revenue requirement through a two-way balancing account

[1] D.20-01-002 at 52-53.
[2] Ex. 231 (SoCalGas Philips Direct) at RDP-A-22. In compliance with Ordering Paragraph 5 of D.16-08-003, SoCalGas incorporated PSEP projects into the TY 2019 GRC. Since the majority of PSEP work was projected to be completed after the 2019 Test Year, a revenue requirement adder was developed specifically for PSEP capital in the post test years. The TY 2019 O&M forecast was an average of the projected level of PSEP O&M over the 2019 – 2021 period.

mechanism.

6. SoCalGas also provided support for additional PSEP projects for a third post-test year (projects forecasted to be completed in 2022) if the request for an additional attrition year were to be approved in this proceeding.[3]

7. As explained in SoCalGas' 2019 GRC testimony, PSEP projects were developed using a risk-informed prioritization methodology:

> As directed by the Commission, the SoCalGas and SDG&E PSEP includes a risk-based prioritization methodology that prioritizes pipelines located in more populated areas ahead of pipelines located in less populated areas and further prioritizes pipelines operated at higher stress levels above those operated at lower stress levels. This prioritization directive and the goals to enhance public safety, comply with Commission directives, minimize customer impacts, and maximize the cost effectiveness of safety investments have led to the development of the PSEP mitigation described in the RAMP.[4]

This methodology was contested by parties and fully litigated in the 2019 GRC proceeding. In the 2019 GRC Decision, the Commission found "SoCalGas' method and cost estimates to be reasonable, appropriate for the proposed projects, and supported by the testimony submitted."[5]

8. The 2019 GRC Decision authorized revenue requirements for 2019-2021 associated with SoCalGas' forecasts for nine of the proposed PSEP pressure test projects, ten of the proposed PSEP replacement projects, and 284 of the proposed valve project bundles subject to a ten percentage point reduction of a risk assessment component of the cost estimates.[6]

9. The Commission determined that the PSEP post-test year attrition mechanism should be based on a forecast of PSEP capital additions beyond test year 2019,[7] because "PSEP

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[3] *See* Ex. 231 (SoCalGas Phillips Direct) at Section X and XI.
[4] *Id.* at RDP-A-18 – RDP-A-19.
[5] D.19-09-051 at 204.
[6] *Id.*, Conclusions of Law ("COL") 43, 44 at 766.
[7] *Id.,* Ordering Paragraph 4 at 776.

capital-related costs [are] not fully reflected in the TY 2019 revenue requirement."[8]

10. In declining to include a third attrition year at that time, the 2019 GRC Decision did not adopt SoCalGas' 2022 proposals, including PSEP-related requests.[9]

SoCalGas' Methodology for Updating the Authorized PSEP Post-Test Year Mechanism in Response to the RCP Decision for 2022 and 2023 is Reasonable.

11. The RCP Decision describes the general methodology for updating revenue requirement results for attrition years as follows: "The post-test year revenue requirements are typically determined by (1) escalating the test year O&M expenses, and (2) authorizing capital expenditures at a level determined by either (i) applying additional escalation factors, or (ii) further review of the applicant utility's actual capital budgets for those years."[10]

12. In the Petition, SoCalGas updates its forecasts for PSEP capital project work for purposes of establishing an attrition mechanism for 2022 and 2023.[11]

13. To establish the 2022 PSEP capital proposal presented in the Petition, SoCalGas began with the 2022 PSEP forecasted project estimates presented in its 2019 GRC Application.[12] These estimates were developed using the same methodology that was found appropriate and reasonable in the 2019 GRC Decision.[13] SoCalGas then applied this methodology to the 2022 PSEP capital forecasts in the 2019 GRC Application. In doing so, the cost forecast for the Line

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[8] *Id.* at 215.
[9] *See* D.19-09-051 at 30 ("Proposals under various topics as well as testimony and other evidence made in those proceedings concerning 2022 are not discussed further in this decision.").
[10] D.20-01-002 at 8.
[11] SoCalGas is not proposing changes to the authorized treatment of PSEP O&M in the proposed 2022 and 2023 post-test year mechanism. In the authorized 2020 and 2021 post-test year mechanism, PSEP O&M was aggregated and treated consistently with other GRC O&M margin. The continuation of the escalation mechanism for O&M to include the additional post-test years is described in the Declaration of Jesse Aragon.
[12] *See* Exhibit 231 (SoCalGas Phillips Direct) at Section X.
[13] *Id.* at RDP-A-49 – RDP-A-54 and 233C (Confidential Supplemental Workpapers to SoCalGas Phillips Direct) at 340-420. The 2022 project forecasts were included to support SoCalGas' proposal for a third (2022) attrition year.

44-1008 project was excluded,[14] and the risk assessment component of the other 2022 forecasted projects was reduced by ten percentage points.[15] The derivation of the revenue requirement associated with the 2022 PSEP capital forecasts is described in Mr. Aragon's declaration. SoCalGas proposes to use these 2022 capital project forecasts to determine the PSEP capital revenue requirement for 2022.

14. This Petition does not propose to include additional PSEP project forecasts for 2023. Rather, as described in Mr. Aragon's declaration, SoCalGas proposes continuation of the mechanism authorized in the 2019 GRC Decision to derive the 2023 revenue requirement for PSEP capital.

15. It is reasonable to use this mechanism to determine the forecasted revenue requirement necessary to support the planned level of PSEP capital project work for the additional 2022 and 2023 attrition years, for several reasons.

16. First and most importantly, SoCalGas' proposal will enable SoCalGas to continue to implement PSEP to enhance the safety of California's gas transmission infrastructure, in accordance with Commission requirements and State law.

17. Second, this mechanism is supported by the evidence in the record of this proceeding (i.e., the detailed PSEP project forecasts for 2022 that were supported by testimony and supplemental workpapers).

18. Third, this mechanism takes into account the inherent challenges of forecasting projects to be executed several years into the future, by extending the cost forecast without inhibiting SoCalGas' ability to sequence the construction in accordance with the approved PSEP decision tree and prioritization process using updated assessments of pipeline conditions,

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[14] D.19-09-051, COL 42 at 766.
[15] *Id.*, COL 44 at 766.

permitting, land acquisition, and material lead times, as well as operational, environmental, community and customer impacts for each project.

19. Finally, as described in Mr. Aragon's declaration, this proposal is also consistent with the adopted post-test year mechanism for capital, in that it uses prior year authorized PSEP capital expenditures and capital additions for the purposes of establishing revenue requirement for future years. As discussed in the declaration of Ryan Hom (Petition Attachment A), SoCalGas will provide detailed project forecasts for the years 2022, 2023, and test year 2024 in its TY 2024 GRC Application. The Commission and interested parties will have the opportunity to evaluate PSEP project forecasts for those years during the TY 2024 GRC proceeding and preview the proposed PSEP level of work in the 2021 RAMP submittal. PSEP will also be included in the annual Risk Spending Accountability Reporting. This proposed approach will align PSEP project forecasts with the rate case plan requirements for other GRC forecasted projects.[16]

20. The total revenue requirement authorized for PSEP for 2019 through 2021 in the 2019 GRC Decision, plus the proposed revenue requirement for PSEP for years 2022 and 2023 described in Mr. Aragon's declaration, supports SoCalGas' current forecasted level of PSEP project work to be completed in the years 2019 through 2023. Thus, SoCalGas' proposal also supports the objectives of PSEP "to enhance public safety, comply with Commission directives, minimize customer impacts, and maximize cost effectiveness of safety investments."[17]

[16] D.07-07-004, Appendix A at A-30-A-32.
[17] D.19-09-051 at 197.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, except as to those matters stated to be on information and belief, and as to those matters, I believe them to be true and correct.

Executed this 9th day of April 2020, at Los Angeles, California.

/s/ Deana M. Ng
Deana M. Ng

ATTACHMENT E

PROPOSED MODIFICATIONS PER RULE 16.4(b)

Proposed Language per Rule 16.4(b)	
New Finding of Fact (FOF)	On January 16, 2020, the Commission issued D.20-01-002, which extended the GRC cycle for each investor-owned utility ("IOU") from three to four years and implemented changes to conduct GRC proceedings more efficiently. For SoCalGas' and SDG&E's current GRC cycle, the Commission designated 2022 and 2023 as additional attrition years and 2024 as the next GRC test year.
New FOF	D.20-01-002 and D.19-09-051 require SoCalGas and SDG&E to petition to modify D.19-09-051 to include the 2022 and 2023 attrition years.
New FOF	SoCalGas' and SDG&E's proposals to add two additional attrition years (2022 and 2023) to this GRC cycle are reasonable.
New FOF	It is reasonable to extend SoCalGas' and SDG&E's post-test year O&M and capital adjustments mechanisms adopted for attrition years 2020 and 2021 to attrition years 2022 and 2023.
New FOF	It is reasonable to derive SoCalGas' and SDG&E's revenue requirements for 2022 and 2023 by starting with the revenue requirements authorized in D.19-09-051 and applying the authorized post-test-year mechanisms to update the relevant forecasts, including updates for capital projects, by updating the revenue requirement for each consecutive year.
New FOF	A Test Year 2020 Cost of Capital was adopted in D.19-12-056 for SoCalGas and SDG&E.
New FOF	It is reasonable to update the applied uncollectible rate, the Commission-approved cost escalation factors, and the authorized rate of return for 2022 and 2023 (set forth in D.19-12-056), as proposed in SoCalGas and SDG&E's petition for modification.
New FOF	It is reasonable to adopt SoCalGas' proposal to use its 2022 capital project forecasts to determine the PSEP capital revenue requirement to be approved for 2022, using the same methodology that was found appropriate and reasonable in D.19-09-051. For 2023 capital for PSEP, it is reasonable to adopt SoCalGas' proposal to continue the mechanism authorized in D.19-09-051 to derive the rest of the 2023 revenue requirement, as described in the petition for modification.
New FOF	It is reasonable to continue the authorized Z-Factor, regulatory accounting provisions, and any other post-test year determinations reflected in D.19-09-051 (including regulatory accounting mechanisms, the measurements of them, and whether thresholds are met) through 2022 and 2023 and be calculated over the GRC cycle.
New FOF	It is reasonable to adopt SoCalGas' and SDG&E's proposed revenue requirements for 2022 and 2023, as set forth in the petition for modification.
New FOF	The disposition of I.19-11-015/-016 (cons.) is being addressed in that RAMP proceeding.