

Decision 20-01-002 January 16, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to
Develop a Risk-Based
Decision-Making Framework to
Evaluate Safety and Reliability
Improvements and Revise the General
Rate Case Plan for Energy Utilities.

Rulemaking 13-11-006

**DECISION MODIFYING THE COMMISSION'S RATE CASE PLAN FOR
ENERGY UTILITIES**

TABLE OF CONTENTS

Title	Page
DECISION MODIFYING THE COMMISSION’S RATE CASE PLAN FOR ENERGY UTILITIES.....	1
1. Background	4
2. The Commission’s Rate Case Plan for Energy Utilities	8
3. The Energy Division Workshop	19
4. Energy Division Recommendations.....	21
5. Discussion	22
5.1. Retention or Change of the Three-Year GRC Cycle.....	28
5.2. Combining PG&E’s GT&S and GRC Proceedings.....	41
5.3. Moving the Due Date for the Public Advocates Office’s Opening Testimony.....	44
5.4. Adopted Revisions to Rate Case Plan.....	47
5.5. Additional Workshops.....	56
5.5.1. Should a Future Workshop Address Standardizing GRC Filings?.....	57
5.5.1.1. Data Request Format	58
5.5.1.2. Standardized Joint Comparison Exhibit.....	59
5.5.1.3. Standard Index for Testimony	60
5.5.1.4. The Base Year and Requirements Regarding Recorded Data	61
5.5.2. Should a Future Workshop Address Stipulated Terms, Rebuttable Presumptions, and Formula-Based Attrition Year Revenue Requirements?	62
5.5.3. Should a Future Workshop Consider Greater Uniformity in the Results of Operation Model?.....	65
5.5.4. Should a Future Workshop Address FERC Accounting?.....	67
5.5.5. Adopted Workshop Topics and Schedule	69
5.6. Should the Commission Open a “Tax Rulemaking”?	72
5.7. Closure of this Rulemaking	73
6. Comments on Proposed Decision	74
7. Assignment of Proceeding.....	75
Findings of Fact.....	75
Conclusions of Law	77
ORDER	78

Appendix A: Adopted Revised GRC Application Filing Schedule, Effective June 30, 2020

Appendix B: Schedule for the Transition from the Current Three-Year GRC Cycle to the Four-Year GRC Cycle

DECISION MODIFYING THE COMMISSION'S RATE CASE PLAN FOR ENERGY UTILITIES

Summary

The Commission manages its General Rate Case (GRC) proceedings for the large energy utilities subject to its jurisdiction in accordance with a “rate case plan” (RCP) that sets the schedule for each milestone in the proceeding.¹ The purpose of the RCP is to ensure that complex and financially significant GRC proceedings follow a predictable schedule that balances the need for timely Commission decisions with procedural fairness for all parties. In this decision we review and address proposals regarding how we could conduct GRC proceedings more efficiently, and whether we should extend the GRC cycle for each utility from three years to four years. We adopt the following:

- The generic GRC cycle is changed from a three-year to a four-year cycle, and the filing deadline shall transition to May 15th of the year that is two years prior to the test year.
- The generic GRC proceeding schedule adopted in Decision 14-12-025 is modified as follows:
 - The filing date for GRC applications is moved from September 1 of the year that is two years prior to the applicant's test year, to May 15th of that year;
 - Additional time is provided to the Commission's independent Public Advocates Office to complete its comprehensive review of the utilities' application and serve its testimony; and

¹ The large energy utilities required to follow this schedule are Pacific Gas and Electric Company, Southern California Edison Company, Southern California Gas Company and San Diego Gas & Electric Company. The smaller energy utilities subject to the Commission's jurisdiction are not required to follow the Rate Case Plan in every detail (Bear Valley Electric Service, Liberty Utilities, PacifiCorp doing business as Pacific Power, and Southwest Gas Corporation).

- PG&E shall combine its currently-separate GRC and Gas Transmission and Storage rate cases into a single rate case application beginning with its 2020 Risk Assessment and Mitigation Phase (RAMP) filing and the GRC application due to be filed in 2021 for its 2023 test year.
- The large energy utilities shall implement their transitions to the four-year GRC cycle according to the schedule specified below:
 - Pacific Gas and Electric Company shall file its next RAMP application, as specified in this decision, in June 2020, and shall file its next combined GRC application, based on a four-year GRC cycle, in June 2021.
 - Pursuant to the Commission's decision on their 2019 GRC applications, Decision 19-09-051, and in order to accommodate the transition to a four-year GRC cycle, Southern California Gas Company and San Diego Gas & Electric Company shall file a petition to modify that decision to add third and fourth attrition years for 2022 and 2023. These utilities' next respective GRC applications, based on a four-year GRC cycle, shall be filed on May 15, 2022 and shall be based on a 2024 test year and 2025-2027 attrition years.
 - Southern California Edison Company shall follow directions forthcoming from the Administrative Law Judge or the assigned Commissioner for its GRC application (A.) 19-08-013 to amend the application to add a third attrition year for 2024. The utility's first four-year GRC application shall be filed on May 15, 2023 and shall be based on a 2025 test year and 2026-2028 attrition years.
- A workshop or workshops will be facilitated by the Commission's Energy Division, in consultation with the Safety and Enforcement Division, as needed, to further explore and develop proposals to increase the efficiency of GRC proceedings, including:
 - Standardizing the organization and format of GRC and RAMP filings;

- The possible use of stipulated terms and rebuttable presumptions to reduce litigated issues, and improving the accuracy of attrition year forecasting, escalation factors, and ratemaking;
- High level consistency in the Results of Operations modeling process across utilities;
- GRC Phase 2 scheduling; and
- Possible frameworks for monitoring attrition year revenue requirements.

This proceeding is closed.

1. Background

This decision concerns “Phase 1” of the General Rate Case (GRC) proceedings for the investor-owned large energy utilities, where the Commission reviews and authorizes the revenue requirement necessary for the utility to recover the reasonable capital investment costs and annual expenses necessary to operate and maintain its facilities and equipment, in a safe and reliable manner. The Commission conducts these proceedings according to a standard “rate case plan” and schedule (RCP) that requires each utility to file a GRC application with the Commission every three years. In a later and separately-filed “Phase 2” of a GRC, the Commission addresses proposals regarding how the revenue requirement that it authorized in Phase 1 should be allocated among customer classes, and collected from those customers in rates.²

The Commission opened this rulemaking in 2013 out of concern that the energy utilities were not explicitly or adequately addressing safety and reliability issues in their GRC funding requests. The Commission determined that the

² For natural gas utilities, the allocation issues are addressed in subsequent cost allocation proceedings, rather than a second phase of their GRC.

assigned Commissioner and Administrative Law Judge (ALJ) in GRC proceedings would be better equipped to guide the proceeding from its inception if the RCP required the applicant utility to include an appropriate showing on safety and reliability issues in its application. Thus, the primary purpose of this rulemaking was to determine whether and how to formalize rules to ensure the effective use by large electric and gas utilities of a “risk-based decision-making framework” to evaluate the safety and reliability improvements requested in their GRC applications.³ However, the Commission also articulated a second purpose for the rulemaking: “in conjunction with this focused review on safety, security and reliability issues, we may also consider broader revisions in the RCP in more general terms to promote more efficient and effective management of the overall rate case process.”⁴

Following a public workshop and several rounds of comments by parties to the rulemaking, the Commission adopted Decision (D.) 14-12-025, its “Decision Incorporating a Risk-Based Decision-Making Framework into the Rate Case Plan.” The Commission adopted a risk-based decision-making framework consisting of a Safety Model Assessment Proceeding (S-MAP), a Risk Assessment and Mitigation Phase (RAMP) proceeding, and the filing of annual post-GRC verification reports consisting of a Risk Mitigation Accountability Report and a Risk Spending Accountability Report.⁵ The Commission also modified the RCP in order to accommodate the newly created proceedings.⁶ In making these

³ Rulemaking (R.) 13-11-006 at 1.

⁴ *Id.*, at 6.

⁵ D.14-12-025, Ordering Paragraph 1.

⁶ *Id.*, Ordering Paragraph 2.

modifications, however, the Commission denied requests by some parties to expand the standard three-year GRC cycle to a four-year cycle.⁷

In September 2015, several parties filed a joint petition for modification (PFM) of D.14-12-025, again requesting that the standard length of the GRC cycle be extended from three years to four years.⁸ The petitioners contended that moving to a four-year GRC cycle would allow better use of both utility and Commission resources, and facilitate the timely completion of the newly created proceedings implementing the risk-based decision-making framework, as well as the GRC proceedings themselves.

The Commission denied the PFM in D.16-06-005, explaining that (as of June 2016) extending the GRC cycle by an additional year would delay incorporation of the RAMP process into future GRC filings of the energy utilities. The Commission also found that the joint parties were renewing arguments that the Commission had already considered and rejected in D.14-12-025. However, the Commission also stated in D.16-06-005 that “we think it is appropriate to explore the GRC cycle length further in the context of timely processing all of the recurring major rate-related proceedings, such as the GRCs, cost allocation proceedings, and PG&E’s gas transmission and storage proceeding, in addition to the added processes of the S-MAP and RAMP.”⁹ The Commission directed

⁷ *Id.*, at 40: “On the three-or four-year GRC cycle, we will retain the three-year cycle. The three year cycle will minimize overlapping GRCs so long as the RCP schedule is followed. We recognize, however, that there are oftentimes other circumstances or events that interfere with the timely proceeding of GRCs. The assigned Commissioner and ALJ shall have the discretion to alter the schedule as may be needed. Should the S-MAP, RAMP, and GRC processes pose scheduling conflicts, we may need to revisit the need for a four-year rate cycle.”

⁸ Joint Petition of SDG&E, SoCalGas and Office of Ratepayer Advocates (Public Advocates Office) for Modification of General Rate Case Cycle Length in Decision 14-12-025, at 7.

⁹ D.16-06-005 at 6.

the Commission's Energy Division to conduct a workshop to address the issues that are involved in moving to a longer GRC cycle, and to prepare a workshop report on whether a longer GRC cycle is worth pursuing.¹⁰ This rulemaking proceeding has remained open to consider the results of the workshop and other miscellaneous changes to the RCP.¹¹

The Energy Division conducted its workshop on January 11, 2017 and completed its workshop report in March 2018. On March 8, 2018 the assigned ALJ issued a ruling that provided the Energy Division's "General Rate Case Plan Workshop Report" (Staff Report) to the service list, accepted the report into the proceeding record, and set a schedule for comments and reply comments on the recommendations made in the Staff Report.

The parties listed below filed and served comments on April 5, 2018:

- Pacific Gas and Electric Company (PG&E);
- Southern California Edison Company (SCE);
- Southern California Gas Company and San Diego Gas & Electric Company (jointly, as SDG&E and SoCalGas);
- the Commission's independent Office of Ratepayer Advocates (hereinafter, the Public Advocates Office);¹²
- the Southern California Generation Coalition (SCGC); and
- The Utility Reform Network (TURN).

SCE and TURN filed and served reply comments on April 19, 2018.

¹⁰ *Id.*, Ordering Paragraph 2.

¹¹ *Id.*, Ordering Paragraph 3.

¹² In 2018 the Office of Ratepayer Advocates (ORA) was renamed the Public Advocates Office of the Public Utilities Commission pursuant to Senate Bill 854 (Stats. 2018, ch. 51). Although all the pleadings in this proceeding were submitted under the name of ORA, this decision updates those references to the Public Advocates Office in order to avoid confusing readers.

The Staff Report and parties' comments and reply comments on that report constitute the record that serves as the basis for this decision.

2. The Commission's Rate Case Plan for Energy Utilities

As noted above and explained in the Staff Report, 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. The large energy utilities are required to file a GRC application every three years with the Commission, meaning they follow a three-year GRC rate case cycle. 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."¹³ The Commission's decision is based on its extensive review of the test year forecasts. 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.

For all its procedural and technical complexity, the Commission's decision in a GRC proceeding can be summarized on a single page, the "Summary of

¹³ The term "attrition" is used in reference to possible effects on utility earnings in the years between rate cases. Hypothetically, if the Commission required that the test year revenue requirement remained unchanged until the next rate case, the utility's earnings in the post-test years would be affected in two ways. If the utility incurred higher costs, its earnings would decrease: earnings "attrition" would occur. Conversely, if the utility incurred lower costs, the utility could retain more revenue for its earnings than it forecast: earnings "accretion" would occur. See, Costello, Ken, "Future Test Years: Challenges Posed for State Utility Commissions," National Regulatory Research Institute Briefing Paper, Report No. 13-08, July 2013, at 2-3 and 7.

Earnings” authorized for the applicant utility in the test year. The table below depicts a typical Summary of Earnings statement:¹⁴

<u>Annual Summary of Earnings</u>			
Line no.			
1			Authorized O&M Expenses
2	plus		Return on Rate Base
3	plus		Depreciation Expense
4	plus		Taxes
<hr/>			
5	equals:		Annual Customer Revenue Requirement

As shown above, the adopted revenue requirement consists of (1) the forecast O&M expenses approved by the Commission, plus (2) the revenues the utility forecasts will be necessary to recover the costs of its capital investments during the test year, and (3) the utility’s estimated tax obligations. The capital-related revenues are expressed indirectly as the sum of (i) the depreciation expense associated with the capital assets in the rate base, and (ii) the return on the utility’s rate base.

Procedurally, a typical GRC proceeding at the CPUC unfolds in the manner described in the quote below:

Required revenues and the rates necessary to realize them are established via the rate case, which is a quasi-judicial procedure designed to provide due process to all affected parties (e.g., the utility, investors, customers) and produce rates which are just and reasonable. As part of the rate case process, regulators evaluate the prudence (i.e., recoverability) of costs after they are incurred.¹⁵

¹⁴ As will be seen below, the utilities calculate the Summary of Earnings using a “Results of Operations” (RO) model; at times the two terms are used interchangeably.

¹⁵ Edison Electric Institute, “Cost of Service Regulation in the Investor-Owned Electric Utility Industry: A History of Adaptation,” prepared by Dr. Karl McDermott, at viii and 12.

The economic literature also discusses the need for timely and predictable Commission action on GRCs and related issues:

Once the revenue requirement is established, the rates are applied to the real time, real world market place where a set of dynamic factors, including demand growth, inflation, and government mandates determines the actual cash flows and earnings of the utility. To the extent that the real world approximates the assumptions used to establish the total revenue requirements, the cost-of-service model can operate effectively with regulatory lag serving as an incentive to control costs. However, if technical, economic, and financial shocks negate these assumed conditions, regulators have been required to search for pragmatic policy adjustments in order to re-establish the balance of interests.¹⁶

Regular participants in GRC proceedings at the CPUC will certainly recognize that the GRC proceedings of the large energy utilities reflect both the necessity of regulation, and the challenges inherent in this form of government oversight.

Referring again to the economic literature, the general rate case proceeding is viewed as the embodiment of what is often described as the “regulatory compact.” This compact is viewed as a contract between the utility’s investors and its customers; as such, it establishes rights, obligations, and benefits for both sides of the bargain:

- Utilities accept the obligation to serve and charge regulated cost-based rates, and customers accept limited entry (i.e., loss of choice) in exchange for protection from monopoly pricing.
- Under this agreement, the utility is provided the opportunity to recover its actual legitimate or prudent costs – determined by a public examination of the utility’s outlays – plus a fair return on capital investment as measured by the cost of obtaining capital in a competitive capital market.

¹⁶ *Id.* at viii.

- Investors will only provide capital for provision of utility services if they anticipate obtaining a return that is consistent with returns they might expect from employing their capital in an alternative use with similar risk;
- Customers will only accept utility rates if they perceive that the rates fairly compensate the utility for its costs, but are not excessive as a result of the utility taking advantage of its privileged position.¹⁷

It is the role of regulatory bodies such as this Commission to ensure that both sides fulfill their respective obligations under this bargain. Given the vastly different resources at the disposal of the utilities and their customers, it is up to the Commission to maintain the balance in outcomes between customers and shareholders. This somewhat theoretical construct becomes very real when the Commission fulfills its responsibility and quantifies this balanced outcome in its decisions in general rate cases.

Our brief summary of the regulatory compact does not reveal anything that is not already well-understood by the utilities and intervenors in GRC proceedings. However, in light of a number of extraordinary catastrophic events involving California's regulated energy utilities in recent years (e.g., the 2010 San Bruno pipeline explosion in PG&E's service territory and the major wildfires in 2007, 2017 and 2018 in SDG&E, PG&E and SCE service territories) a review of first principles may be in order. As the utilities consider and implement corrective measures after these events, the forum for Commission review and authorization of the related capital investment costs and operating expenses is,

¹⁷ *Id.* at 6.

either directly or indirectly, each utility's GRC proceeding.¹⁸ As such, utility investors and utility customers can reference over a century of legal and regulatory history that confirms the Commission's role is not to merely pass utility cost estimates on to ratepayers, but rather to independently determine the just and reasonable level of costs necessary for the utility to meet its obligations.

The authority of state regulatory commissions dates back to 1877, when the U.S. Supreme Court upheld the power of government to regulate private industries by recognizing that certain economic activities were so critical to the functioning of a modern society that government has the right to oversee the prices charged to assure that such services are provided to the public in a reasonable manner.¹⁹ The *Munn* decision was limited by subsequent Court decisions, though not its broad application to state regulation of public utilities. However, it was not until 1944 that the Court directly articulated the notion that some sort of bargain offers guidance to regulators, establishing a principal that continues to guide every rate case: in its *Hope* decision, the Court stated that the regulatory process involved a balancing of customer and stockholder interests:

[t]he rate-making process ... i.e., the fixing of just and reasonable rates, involves a balancing of the investor and the consumer interest.²⁰

We find it important to restate this principal in order to remind parties that the *benefits* to each side of the regulatory compact come with corresponding *obligations* for each side. In the remainder of this section we briefly review how

¹⁸ See, for example, Pub. Util. Code § 8386.4(b)(1) which provides that the Commission shall consider whether the cost of implementing each utility's wildfire mitigation plan is just and reasonable in that utility's general rate case application.

¹⁹ *Munn v. Illinois*, 94 U.S. 113, 146 (1877).

²⁰ *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), at 603.

the CPUC came to interpret the terms of the regulatory compact and how it would act to maintain the balance of interests contemplated by the *Hope* court.

The Commission has managed large energy utility GRC proceedings in accordance with some form of “rate case plan” since 1977, when it adopted its first “Regulatory Lag Plan for Major Utility General Rate Cases” (RLP).²¹ As the title of the RLP indicates, the Commission has always recognized the challenges created by “regulatory lag.” In 1997 the Commission summed up the intervening 20 years and succinctly articulated the purpose of such plans:

With regulatory lag i.e., the delay between seeking and obtaining relief from the Commission confronting our regulatory process, we adopted a Regulatory Lag Plan ... on July 6, 1977. The experience gained from processing general rate changes under the RLP enabled us to consider modifications that would make the RLP more workable and *further minimize regulatory delay while providing an administrative forum with fairness to all.*²²

Notably, in the text quoted above the Commission expressed its dual goals as minimizing regulatory delay without sacrificing fairness for all parties. As we

²¹ Resolution A-4693, July 6, 1977. In 1982, the Commission revised the RLP and renamed it the “Rate Case Processing Plan” (RCPP). *See*, Resolution ALJ-149, October 20, 1982. Perhaps reasoning that its handiwork can always be further improved, the Commission declared two months later that “the name of the RCPP is too lengthy and should be changed to Rate Case Plan (RCP).” *See*, D.82-12-072 at 2.

²² R.97-06-038, “Order Instituting Rulemaking on the Commission's Own Motion into the Establishment of a Rate Case Plan for Small Local Exchange Carriers” at 2. Emphasis added.

We note that the economic literature distinguishes between two types of “regulatory delay” or “lag”: (1) the lag between rate cases, and (2) the lag during the pendency of a rate case. Over the years, the CPUC has established ratemaking mechanisms that reduce the risk that the lag between rate cases will result in utility revenues not matching forecast costs. For the second type of lag, which this Commission terms “regulatory lag,” the literature notes that it “can cause gaps in the ability of utilities to recover prudently incurred costs or, depending on the circumstances, may cause costs in the test year to be overstated.” *See*, Edison Electric Institute, “Cost of Service Regulation in the Investor-Owned Electric Utility Industry: A History of Adaptation,” prepared by Dr. Karl McDermott, at 15-16.

discuss further below, an important result when the Commission achieves these goals is that all stakeholders, most notably the utilities' investors and customers, can rely on the Commission to process GRCs in a manner that produces predictable results.

In addition to acting on its own motion the Commission also modified the RCP over the years to incorporate legislative directives. In 1951 the passage of the Public Utilities Act established the Public Utilities Code (Pub. Util. Code) in its modern form. At that time, Pub. Util. Code § 311 (hereinafter, Section 311) was limited to defining the powers of the Commissioners and "examiners" to administer oaths, examine witnesses, issue subpoenas, and receive evidence.²³ Since that time, the Legislature periodically amended and expanded Section 311 in ways that required the Commission to update the RCP to remain consistent with the express intent of the Legislature. In 1982 the Legislature amended Section 311 to define the role of ALJs in more detail, introducing the requirement that "[t]he proposed decision of the administrative law judge shall be filed with the commission and served upon all parties to the commission without undue delay but in no event later than 90 days after the matter has been submitted for decision."²⁴ Notably, the same amendment clarified that

[i]t is the intent of the Legislature that the implementation of this act shall not require extension of the time period currently required for the Public Utilities Commission to act on any matter before it, and that the schedule for acting on rate increase applications by the commission, as specified in the commission's Regulatory Lag Plan

²³ Stats 1951, ch. 764. In 1979 the Legislature amended Section 311 to refer to "administrative law judges" instead of "examiners."

²⁴ Stats. 1982, ch. 1542.

for Major Utility General Rate Cases...shall not be changed by the provisions of this act.²⁵

The Commission again found it necessary to revise the RCP after the Legislature further amended Section 311 in 1986 to require that, after the issuance of the ALJ's proposed decision, the Commission shall issue its own final decision not sooner than 30 days following that date.²⁶ The 1986 amendments led the Commission to initiate R.87-11-012, its "Order Instituting Rulemaking to Revise the Time Schedules for the Rate Case Plan and Fuel Offset Proceedings." The Commission's list of tasks for R.87-11-012 indicate its continuing focus on the goals of timeliness and procedural fairness:

1. Reflect the requirements of Section 311 in the processing of GRCs and energy offset proceedings;
2. Develop reasonable time schedules for processing GRCs and energy offset proceedings; and
3. Consider changes to GRCs that could ease the burden of issuing year-end decisions.²⁷

The Commission proceeded to adopt a number of major changes to the RCP in D.89-01-040, each of which is reflected in the current RCP. First, the Commission established a generic annual cost of capital proceeding for energy utilities, to remove that workload from GRCs. Second, the Commission moved electric rate design issues to a newly created Phase 2 proceeding; in subsequent decisions the Commission moved the related issues of marginal costs and cost allocation to Phase 2 as well. The Commission also specified in D.89-01-040 that cost allocation and rate design for gas utilities would be addressed in separate

²⁵ *Ibid.*

²⁶ Stats. 1986, ch. 893.

²⁷ D.89-01-040 in R.87-11-012, at 2.

Annual Cost Allocation Proceedings (ACAPs, which more recently have taken the form of biennial, triennial, or simply “gas cost allocation proceedings, i.e., BCAPs, TCAPs or GCAPs). Finally, the Commission established new and separate proceedings for the reasonableness reviews of the electric utilities’ energy procurement.²⁸

The streamlined RCP framework adopted in D.89-01-040 remained essentially unchanged for the next 25 years.²⁹ However, its significant procedural modifications and narrowing of scope for Phase 1 proceedings did not result in dramatic improvements in the timely processing of the now-streamlined GRC proceedings. Indeed, although the instant rulemaking focused on developing the S-MAP and RAMP, the Preliminary Scoping Memo included in the Rulemaking invited parties to submit comments on six sets of questions, listed below. Questions 3 – 6 concerned procedural aspects of the GRC process itself:

1. Process to provide appropriate analysis and testimony on safety and risk management;
2. Comprehensive review of safety, reliability, security, and risk management in the utilities’ GRC applications;
3. Timing of the GRC applications;
4. RCP schedule;

²⁸ For PG&E, SCE and SDG&E that proceeding has become the Energy Resource Recovery Account (ERRA) compliance review, and is no longer an “after-the-fact” reasonableness review of utility procurement decisions. For PacifiCorp and Liberty Utilities, that proceeding is the Energy Cost Adjustment Clause (ECAC).

²⁹ Several Commission decisions in the intervening years made non-substantive changes to the RCP, such that the RCP adopted in D.14-12-025, which we modify in this decision, was itself a modification of the RCP adopted by the Commission in D.07-07-004. That decision modified the RCP adopted in D.93-07-030, which in turn had modified the RCP adopted in D.89-01-040, albeit only for SCE.

5. Uniform application of the provisions of the RCP; and
6. Reducing complexity.³⁰

Parties provided responses to these questions in their January 2014 comments on the Rulemaking. Next, pursuant to the May 15, 2014 Scoping Memo, parties filed and served comments and reply comments on the RCP issues on July 25 and August 22, 2014, respectively.

Consistent with the schedule established in the 2014 Scoping Memo, in D.14-12-025 the Commission approved its risk-based decision-making framework to evaluate safety and reliability improvements in the energy utilities' GRC proceedings. Where necessary to accommodate this new framework, the Commission also revised the RCP schedule adopted in Appendix A of D.07-07-004.³¹ However, the Commission also noted that a second phase, and a separate decision, would address proposals to revise the RCP to promote more efficient and effective management of the overall rate case process.³² As noted above, in D.16-06-005 the Commission established the workshop process that led to the Staff Report and parties' associated recommendations that we address in today's decision.

The current RCP is provided in Table 4 of D.14-12-025 (GRC Application Filing), and reproduced on the following page.

³⁰ R.13-11-006 at 10-16. In addition, the May 15, 2014 Scoping Memo determined that a first round of comments would provide the record for a Commission decision addressing questions #1 and #2 regarding the risk-based decision-making framework, while a second round of comments would provide the record for a subsequent Commission decision addressing questions #3 through #6 regarding possible revisions to the RCP.

³¹ D.14-12-025, Ordering Paragraph 2.

³² D.14-12-025 at 9, citing the May 15, 2014 Scoping Memo at 6.

Table 1
Decision 14-12-025
Current GRC Application Filing Schedule³³

Date	Day #	Event
Test Year minus-3		
September 1		Utility requests initiation of RAMP proceeding
By November 15		RAMP Order Instituting Investigation (OII) is opened
By November 30		Utility files its RAMP submission in the OII
Test Year minus-2		
September 1	0	Utility files GRC application, and serves prepared testimony
30 days after Daily Calendar notice		Due date for protests and responses to GRC application, pursuant to Rule 2.6(a) ³⁴
By October 15	44	Utility holds public workshop on overall GRC application
By October 31	60	Prehearing Conference held
	90	Scoping Memo of Assigned Commissioner issued
Test Year minus-1		
By February 20	172	Public Advocates Office serves opening testimony
By March 17	197	Intervenors serve opening testimony
May 1	242	Concurrent rebuttal testimony served
March/ April		Public Participation Hearings
May/June	270	Evidentiary hearings begin, if needed
	289	Evidentiary hearings end
May/June		Update testimony and hearings, if necessary
To be decided	324	Briefs filed
To be decided	345	Reply briefs filed, proceeding submitted for Commission decision
September/October	425	Proposed decision issued
November	455	Final decision adopted
Test Year		
January 1	487	Effective date

³³ D.14-12-025, at 42 (Table 4). For further clarity, we have added the column labeled “Day #” to indicate the time that passes between various milestones. This information was included in earlier versions of the RCP.

³⁴ All references to “Rules” in this decision are to the Commission’s Rules of Practice and Procedure.

As will be seen below, some of the changes to the RCP schedule adopted in D.14-12-025 have proven to be overly optimistic, or unrealistic. For example, the schedule assumes the proceeding will be concluded in 16 months, even though Pub. Util. Code § 1701.5(a) provided for 18 months from the date the scoping memo was issued in the proceeding.³⁵ The Commission also shortened the deadline for the Public Advocates Office to serve its testimony by two months, which has proven to be unreasonable for development of a comprehensive record.

3. The Energy Division Workshop

The Energy Division staff organized the workshop agenda and discussions to focus on two primary questions: (1) how to process GRCs more efficiently, and (2) whether to extend the standard GRC cycle to four years. Staff provided parties with discussion questions prior to the workshop, so that participants were prepared to discuss these issues in depth.

The morning session of the workshop addressed the topic of “facilitating the timely completion of GRCs.” Staff posed the following questions to participants prior to the workshop to stimulate discussion:

1. Does the current RCP schedule allow sufficient time for the utilities, all intervening parties, and Commission staff to process GRC proceedings in a timely manner? If not, why not?
2. Are there ways to reduce the complexity of GRC proceedings and streamline GRC filings? What are they?
3. What are other areas needing improvement within the current RCP?

³⁵ Section 1701.5 was amended in 2016 to modify the term “scoping memo is issued” to “proceeding is initiated” which had the effect of shortening the prior statutorily-allowed timeline by 2 or 3 months.

4. Are there things the utilities or parties can do to assist the Commission to review GRC filings more efficiently? If so, what are they?³⁶

The Energy Division invited a panel of speakers to address these questions, consisting of representatives from the Commission's Safety Enforcement Division (SED), SDG&E and SoCalGas, PG&E, Public Advocates Office, and TURN. Participants discussed the challenges that have impeded the Commission from resolving GRC proceedings according to the RCP schedule and possible ways to help the Commission process GRC proceedings more efficiently.³⁷

The afternoon session of the workshop addressed the topic of "the pros and cons of a three-year versus four-year GRC cycle." Staff again provided a number of questions to participants prior to the workshop:

1. Does a four-year GRC cycle relieve constrained resources issues (Commission staff – ALJ, Energy Division, SED, Public Advocates Office, and parties)? What resources would be freed up with the four-year cycle that are currently constrained by the three-year cycle?
2. What processes and/or procedures are improved with a four-year GRC cycle? What other benefits does a four-year GRC cycle bring?
3. What issues does a four-year cycle create that would not occur in a three-year cycle?
4. Why should the Commission pursue or not pursue a four-year GRC cycle? What assurances are there that a four-year cycle wouldn't suffer the same delays as the three-year cycle?³⁸

³⁶ Staff Report at 6.

³⁷ *Id.*, at 6-12.

³⁸ Staff Report at 21.

Panelists from the Sempra Utilities (SDG&E and SoCalGas), PG&E, Public Advocates Office, and TURN discussed the challenges of a three-year rate case cycle versus a four-year rate case cycle.³⁹

4. Energy Division Recommendations

The Energy Division's post-workshop Staff Report included a detailed review and discussion of parties' presentations and positions (Appendix A of the Staff Report provides links to parties' workshop presentations, which are posted on the Commission's website). The Staff Report concluded with the following recommendations:

1. The Commission should retain the current three-year GRC cycle, because its drawbacks are outweighed by challenges created by moving to a four-year cycle.
2. The Commission should direct PG&E to combine its gas transmission and storage (GT&S) and GRC proceedings, because a single proceeding would provide the Commission with the best overall picture of PG&E's operations.
3. The Commission should modify the Rate Case Plan to move the submittal date for the Public Advocates Office's opening testimony from the current February date to April, because the additional time is necessary for the Public Advocates Office to prepare the comprehensive testimony that the Commission requires for its decision-making.
4. In order to improve the efficiency of GRC proceedings, Energy Division should host additional workshops to address the following topics:
 - i) Broader standardization of GRC filings across the utilities;
 - ii) The feasibility for the Commission to adopt stipulated terms or rebuttable presumptions in order to reduce litigated issues;

³⁹ *Id.*, at 21-23.

- iii) Results of Operations (RO) model uniformity; and
 - iv) The feasibility of utilities submitting their GRC requests using the standard FERC system of accounts.
5. The Commission should open a rulemaking to revisit its policies on the utilities' recovery of income tax expenses and related ratebase issues.

As noted above, parties were invited to submit comments and reply comments on those recommendations. We turn to our discussion of parties' recommendations below.

5. Discussion

At the outset of our discussion, it is important to be clear about what we are trying to accomplish with any modifications to the RCP that we adopt in this decision. Our goals must also account for the statutory requirements described above, as well as others that apply to ratesetting proceedings such as GRCs.⁴⁰

First, we should change the RCP if it will improve our ability to meet our obligations under the Public Utilities Code. Pub. Util. Code § 451 requires us to ensure that utility rates are "just and reasonable." Pub. Util. Code § 1701.3 requires that our decisions on utility GRC applications be "based on evidence in the record."⁴¹ If not, our decisions may be annulled if a reviewing court finds they are not supported by the findings, or are not supported by substantial evidence in light of the whole record.⁴² Procedurally, the Commission must

⁴⁰ As noted above, in D.14-12-025 the Commission recognized that "there are oftentimes other circumstances or events that interfere with the timely proceeding of GRCs." D.14-12-025 at 40. Nevertheless, our purpose in this decision is to revise the RCP plan and schedule so that, absent intervening circumstances, the Commission can predictably meet the expectations of the applicants and intervenors.

⁴¹ Pub. Util. Code § 1701.3 (j).

⁴² Pub. Util. Code § 1757 (a)(3) and (a)(4).

complete GRC proceedings within 18 months of the initiation of the proceeding (i.e., the date the utility files its application).⁴³ Within the specified time frame, Pub. Util. Code § 311(d) requires that the proposed decision of the assigned ALJ or the assigned commissioner shall be issued not later than 90 days after the matter has been submitted for decision and the Commission shall not issue its decision sooner than 30 days following issuance of the proposed decision.⁴⁴

Second, our review of the Staff Report and parties' comments indicate that we should change the RCP if we can better satisfy the "must-haves" expressed by the utilities, the Public Advocates Office, and the other parties that routinely intervene in GRC proceedings. Those priorities affect our options regarding modifications to the RCP schedule in significant ways:

- The utilities want the Commission to issue a timely final decision adopting their revenue requirement in time to be implemented on January 1st of the test year;
- The Public Advocates Office requires sufficient time to conduct discovery and prepare its testimony, because its analysis and recommendations serve as a point of reference for the testimony served by other intervenors a month later;
- The other intervenors should also be provided with sufficient time after the Public Advocates Office serves its testimony, to complete their own discovery and prepare their testimony;
- Once all testimony has been served, all parties in the proceeding should have sufficient time to prepare their rebuttal testimony;

⁴³ Pub. Util. Code § 701.5 (a). However, the Commission may specify a later resolution date in the scoping memo for the proceeding; *see*, Pub. Util. Code § 1701.5 (b).

⁴⁴ Pursuant to Rule 13.14 (a) (Submission and Reopening of Record), a proceeding shall stand submitted for decision by the Commission after the taking of evidence, the filing of briefs, and the presentation of oral argument as may have been prescribed.

- After rebuttal testimony has been served, all parties should have sufficient time to prepare for evidentiary hearings, and to subsequently prepare post-hearing briefs and reply briefs; and
- Once the case is submitted, the assigned ALJ and Commission staff should have sufficient time to prepare the proposed decision, and to calculate the resulting Summary of Earnings and authorized annual revenue requirements using the RO model.

Our consideration of the challenges listed above is illuminated by our very recent experience in SCE's test year 2018 GRC proceeding (A.16-09-001). That case was a "typical" GRC in many ways because it closely tracked the RCP schedule mandated by D.14-12-025:

- SCE filed and served its GRC application on the September 1 due date;
- The schedule adopted in the scoping memo provided almost all the other "must-haves" listed above:
 - ORA received two extra months to prepare its testimony;
 - the intervals between other major procedural milestones were established as requested by parties;
 - based on the submittal date in the Scoping Memo, the proposed decision would be issued by the end of December 2017 for consideration by the Commission at a voting meeting 30 days later, i.e., approximately one month after the 2018 test year began.
- All the major issues in the case were fully litigated, rather than settled, so the "typical" three weeks of evidentiary hearings were held, and voluminous briefs and reply briefs were filed and served by SCE, Public Advocates Office and other intervenors.

The proceeding tracked the schedule required by the RCP through the submittal date in September 2017, when reply briefs were filed and served. From that point onward, however, the Commission did not follow the RCP. In fact, the proposed decision of the two assigned ALJs was issued on April 12, 2019 (i.e.,

more than 18 months after the submittal date). The Commission adopted the PD at its next meeting on May 16, 2019. In short, the applicant and the other parties met the requirements and deadlines of the RCP, but the Commission, collectively, did not.⁴⁵

We consider a delay of this magnitude to be a one-time occurrence. Still, the long delay in issuing this particular PD was merely an extreme example of what parties consider to be typical in large GRC proceedings: the PD is rarely completed and issued by the 90-day statutory deadline.

Based on our review of the history of the RCP at the Commission, related statutory requirements, and with the benefit of very recent hindsight regarding the SCE GRC, we nevertheless find that several relatively simple changes will address many of the challenges created by the current RCP schedule. Those scheduling changes, along with other procedural recommendations from the Staff Report or parties that we also adopt herein, should greatly improve our ability to produce timely GRC decisions following a fair administrative hearing process, on a schedule that provides predictable outcomes for the utilities and the stakeholders in the regulatory compact: investors and customers.

To simplify the solution, we can begin with two “must-haves” and work backwards from those milestones to create a new RCP schedule. First, we should plan that the Commission will issue its final decision on December 1st of the year preceding the test year. This meets the utilities’ stated must-have and provides them with 30 days to incorporate the Commission’s decision into any rate change that takes effect on January 1st of the test year. Second, we should modify the

⁴⁵ For the purposes of this illustration, we acknowledge but ignore the fact that the proceeding also remained open in order to address the passage in late 2017 of the Tax Cut and Jobs Act, because the proposed decision would have already been issued if the RCP had been followed.

RCP schedule to provide the Public Advocates Office with the time it has consistently stated it requires to conduct discovery and prepare its testimony. With these two “must-haves” in place, we should also maintain the time gaps between other major milestones in the proceeding, as requested by other parties. Finally, a realistic period of time should be established for the ALJ or ALJs to draft the PD and oversee calculation of the resulting Summary of Earnings.

With the above scheduling milestones in mind, we find that if we modify the RCP schedule to require the utilities to file their GRC applications several months earlier, on May 15th instead of September 1st of “test-year minus-2” then the Public Advocates Office can be given a realistic amount of time to prepare its testimony, and the utilities can receive their decision prior to the start of their test year, all while preserving the other intervals between major milestones that parties have indicated are important to them.

The illustrative generic schedule in Table 2 below is the result of applying these criteria:

Table 2
Illustrative Generic GRC Schedule
(RAMP omitted)

Date	~ Day #	Milestone
Test Year minus-2		
May 15	0	Utility files GRC application and serves prepared testimony
December 15	215	Public Advocates Office serves opening testimony
Test Year minus-1		
January 9	240	Intervenors serve opening testimony
February 23	285	Concurrent rebuttal testimony served
March 19	310	Evidentiary Hearings Begin
April 8	330	Evidentiary Hearings End
May 13	365	Briefs filed
June 3	385	Reply briefs filed
November 1	535	Proposed decision mailed for comment
December 1	565	Final decision adopted
Test Year		
January 1	595	Effective date of final decision

These changes are deceptively simple. However, given the complexity of GRCs and the importance of adhering to a schedule that results in a final Commission decision by a predictable “date-certain” we note that the Commission must still support major GRC proceedings with adequate staff resources to ensure success. This begins at the ALJ level, but extends to the staff level in the industry divisions so that the ALJs and the Commissioners have sufficient analytical resources to support their decision-making. In fact, this expanded staffing is already occurring in the Commission’s Energy Division and Safety and Enforcement Division so we need mainly to ensure that this trend continues and is sustained.

With this partially modified RCP schedule as our initial reference point, we turn next to the specific recommendations in the Staff Report, and determine how a modified schedule would or would not accommodate them.

5.1. Retention or Change of the Three-Year GRC Cycle

As we explained above, in D.16-06-005 the Commission indicated it wished to explore lengthening the GRC cycle “in the context of timely processing all of the recurring major rate-related proceedings, such as the GRCs, cost allocation proceedings, and PG&E’s gas transmission and storage proceeding, in addition to the added processes of the S-MAP and RAMP.”⁴⁶

In our view, parties at times conflate two distinct issues to contend that (1) the Commission would find it easier to complete GRCs “on time” if (2) the GRC cycle was lengthened from three years to four years. We disagree with this formulation. In order to issue a GRC decision prior to the test year, the Commission, the ALJs and the staff must process a large amount of information and accurately calculate a large revenue requirement in a short period of time. Given the complexity of large energy GRCs, in practical terms it will remain difficult to prepare the draft decision within the 90-day statutory deadline following submittal of the proceeding, regardless of whether the GRC cycle is three or four years. That said, although we do not consider a four-year GRC cycle as *the* solution to the need for timely decisions, parties offered other reasons for lengthening the GRC cycle, and we consider those now.

At the outset, we note the Staff Report recommends the Commission retain a three-year GRC cycle at this time.⁴⁷ Staff acknowledges the drawbacks of a three-year cycle (primarily related to the relative burden placed on resources of the applicant, the intervenors, and the Commission), but suggests these

⁴⁶ D.16-06-005 at 6.

⁴⁷ Staff Report at 28, Section 7.4.

drawbacks are outweighed by the potential problems that could come with a longer GRC cycle, such as:

- Increased uncertainty regarding forecast expenditures for the third attrition year;
- Greater reliance on the accuracy of post-test year ratemaking mechanisms;
- Concerns that attrition year revenue requirements tend to be higher than test year revenue requirements (perhaps due to less scrutiny of the attrition year forecasts); and
- Concerns that it may be more difficult for the Commission to address emergent issues during the three attrition years, particularly given the rapid changes currently occurring in the electric sector (e.g., expected increases in distributed energy resources and, most recently, increased wildfire-related costs).⁴⁸

Staff tempers its recommendation to retain a three-year cycle by noting workshop participants seemed most concerned that a four-year GRC cycle would result in greater uncertainty about attrition year forecasts and post-test year ratemaking. Staff thus recommends the Commission reconsider the merits of a four-year GRC cycle if the Commission receives input from future workshops that addresses these concerns:

If the Commission were able to establish a uniform and consistent attrition year ratemaking mechanism that would factor in uncertainties during the attrition years, the risks of inaccurate cost forecasts associated with an additional attrition year would be mitigated.⁴⁹

Retention of the current three-year cycle is supported in the comments and/or reply comments of SCE, SCGC and TURN. SCGC states its agreement

⁴⁸ *Ibid.*

⁴⁹ *Ibid*, emphasis added.

with Staff's framing of the potential problems of a four-year cycle (summarized above) and adds that it is unclear to SCGC how standardizing attrition year ratemaking would address Staff's concerns: "standardization would not address the uncertainty that is inherent in forecasting an additional year of attrition year experience, and standardization would not address issues that may emerge during the attrition period."⁵⁰ TURN also concurs with Staff's recommendations and supporting analysis,⁵¹ while also endorsing Staff's recommendation that a workshop process further explore a third attrition year while "retaining the three-year GRC cycle in the meantime."⁵² SCE does not oppose a four-year cycle "outright" but contends that a change to a four-year cycle must (1) include an attrition year mechanism that provides the funding necessary for safe and reliable service, and does not lead to shortfalls in authorized spending; (2) incorporate "[a] greater tolerance on the part of the Commission and parties with respect to errors and variances in forecasting;" and (3) consider the necessity of using a Z-factor mechanism to "help mitigate unforeseen developments that necessarily are more likely to occur in the attrition period when a rate case cycle is extended another year."⁵³

Movement to a four-year cycle is supported by PG&E, SDG&E and SoCalGas, and the Public Advocates Office. PG&E links its support to "appropriate attrition mechanisms and other mechanisms to adjust the revenue

⁵⁰ SCGC Comments at 1 and 2.

⁵¹ TURN Comments at 2.

⁵² TURN Reply Comments at 5. TURN clarifies that it is not offering an opinion on Staff's premise that the risks associated with an additional attrition year could be mitigated by (in Staff's words) "a uniform and consistent attrition year ratemaking mechanism that would factor in uncertainties during attrition years."

⁵³ SCE Comments at 2-3.

requirement during the GRC period – if needed – to address unusual circumstances.” PG&E also notes the four-year cycle would provide the Commission with additional time to weigh “the extraordinary amount of evidence” presented in GRCs; to review additional financial data, including the data regarding the IOUs’ expenditures in the filing year; allow an improved assessment of the IOUs’ risks and risk-related spending, including possibly changing the timing of the RAMP to allow for better integration into the IOUs’ GRCs.⁵⁴ PG&E does acknowledge the concerns of Staff and other parties about adding a fourth year, but believes they can be addressed through an appropriate and uniform attrition mechanism, more flexibility regarding rate adjustments between GRCs, and existing memorandum accounts to address extraordinary circumstances and other anticipated expenses.⁵⁵ PG&E concludes by emphasizing its agreement with Staff that resolving the attrition issue and examining processes to request interim changes to the revenue requirement where appropriate could resolve some of the larger concerns that led Staff to recommend retaining a three-year cycle.⁵⁶

SDG&E and SoCalGas reiterate their support for a four-year cycle. Here, they endorse further efforts to standardize attrition mechanisms. They also note that the RAMP phase adds a long lead time and this adds to resource constraints on all parties, including Commission staff, utilities, and intervenors.

Lastly, the Public Advocates Office has consistently advocated for a four-year cycle. As the party that conducts the most comprehensive quantitative

⁵⁴ PG&E Comments at 4-5.

⁵⁵ *Id.* at 5.

⁵⁶ *Id.* at 5-6.

analysis of GRC filings, their comments include a useful explanation of one challenge inherent in the three-year cycle:

Test years of the initial case serve as base years for the following rate case. This presents a problem because recorded test year costs may not be representative of future costs, as utilities often initiate new programs during the test year, and these initial costs may not be representative of a more stable or steady-state level of expenses or expenditures. A 4-year GRC term allows for better utility financial and operational management of spending and investment.⁵⁷

The Public Advocates Office's comments also reference testimony by SDG&E and SoCalGas in their then-pending GRC applications, where both utilities proposed that the Commission authorize four-year GRC cycles (2019-2022). SDG&E noted that the GRC process has become more complex and subject to extended delays, which is now compounded by new processes, reviews, and reporting emerging from the S-MAP and RAMP proceedings.⁵⁸ SoCalGas echoed SDG&E, and added that a four-year GRC cycle would "reduce the administrative burden on all parties, and allow the utility to more effectively operate its business while implementing new risk-mitigation and accountability structures, processes and reporting requirements."⁵⁹

While we acknowledge Staff's reasons for retaining the three-year cycle, we adopt a four-year cycle in this decision. As summarized above, we have found parties' comments on both sides of this question to be very useful in deciding whether to move to a four-year GRC cycle. Based on our review, we find that a four-year cycle should improve the GRC process in two ways. First,

⁵⁷ Public Advocates Office Comments at 5-6.

⁵⁸ *Id.*, at 4-5, quoting SDG&E testimony in A.17-10-007.

⁵⁹ *Id.*, at 5, quoting SoCalGas testimony in A.17-10-008.

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.

The first of these expected improvements is the most compelling reason for this shift. It is important to create more time for the utilities to focus on day-to-day operations while implementing the still-relatively-new framework for risk-mitigation and accountability that we established in D.14-12-025. We agree with parties' comments contending that the Commission's directives can be better implemented if the GRC cycle is longer. By lengthening the GRC cycle we can shift Commission resources to implementing the expanded utility reporting requirements. This will assist our oversight over utility risk management and safety spending, resulting in greater transparency and accountability of utility actions. We finalized this reporting framework earlier this year in D.19-04-020, our decision adopting risk spending accountability reporting requirements and safety performance metrics for PG&E, SCE, SDG&E and SoCalGas. That decision reviewed the first S-MAP applications filed by these utilities pursuant to D.14-12-025 and finalized the following reporting requirements in order to "allow Commission staff to more readily review and verify these safety-related activities, and to understand the reasons for the changes in priority that may have taken place."⁶⁰

⁶⁰ D.14-12-025 at 46.

- PG&E, SCE, SDG&E and SoCalGas shall report annually on 26 safety performance metrics to measure achieved safety improvements.
- To improve understanding of the metrics, the reports shall include examples of how the metrics were used to improve safety training, take corrective action and support risk based decision-making.
- The reports shall include summaries of how reported data reflect progress against the risk mitigation and management goals approved in each utility's applicable RAMP filing and GRC application, and shall identify and provide additional information for any metrics that may be linked to financial incentives.
- Each utility shall file an annual Safety Performance Metrics report. The Commission's Safety and Enforcement Division staff will submit a review of each report.
- A standard format is established for the annual Risk Spending Accountability Reports (RSARs) by the utilities, which will report on deviations between approved and actual risk mitigation and maintenance spending and activities. A process for parties to comment on the RSARs is established.

In sum, then, the first advantage we see in moving to a four-year GRC cycle is that we expect the extra year between each utility's GRC to facilitate the efforts of the Commission, its staff, and intervenors to use the mandated reporting to fulfill the intent expressed by the Commission in D.14-12-025:

It is our intent that the adoption of these additional procedures will result in additional transparency and participation on how the safety risks for energy utilities are prioritized by the Commission and the energy utilities, and provide accountability for how these safety risks are managed, mitigated and minimized.⁶¹

⁶¹ *Id.* at 2.

The second improvement we expect from moving to the four-year cycle is related to the first, but warrants separate discussion: a longer GRC cycle will facilitate the Commission's adjustment to an emerging reality of modern utility regulation, one that implies a fundamental change in the role of GRC proceedings. In earlier days, the theoretical and real-world purposes of a GRC were essentially the same: the Commission authorized the revenue requirement necessary to allow the utility to recover the reasonable costs of providing safe and reliable service, and to have an opportunity to earn a fair return on its investments. This focus on basic utility service was a workable approach during a time of less rapid technological change, relatively stable costs, and growing populations and demand for utility service. The core activities of the GRC process needed only to be repeated on a periodic basis to maintain fairness for all stakeholders.

Over time, GRC proceedings at the Commission have become much less simple and straightforward. For example, in our review of the "regulatory compact" earlier in this decision, we noted that a utility's response to rapidly unfolding events that affect utility service, such as the catastrophic wildfires in 2007, 2017, 2018 and now, 2019 may require a utility to fund its response by quickly re-directing Commission-authorized GRC funding from its originally-intended purpose to a wholly different purpose. Under the Commission's standard GRC framework, those re-prioritizations would be subject to review in the utility's next GRC, often long after the event. The Staff Report noted that workshop participants discussed the relatively rapid developments in the electric utility industry in recent years; the utilities, especially, described the challenges within the current GRC framework of

bringing “emergent issues” with substantial revenue requirement implications to the Commission’s attention in attrition years.

Moving to a four-year cycle will enable the Commission to become more involved in monitoring how utilities reprioritize authorized GRC funding, not less. Implementing a four-year cycle and its attendant widening of “forecast error” means that the Commission, the utilities and stakeholders will be able to spend less time in a GRC trying to achieve precision in forecasts, and instead dedicate more time and effort between GRCs to monitoring how each utility spends its authorized revenue requirements. If the Commission is to accommodate the utilities’ suggestions that a four-year cycle requires a more flexible regulatory approach, the utilities must reciprocate by more openly engaging in an ongoing dialog throughout the GRC cycle that enables the Commission to review their activity in a transparent manner and ensure the utilities are held accountable for how they spend ratepayer funds.⁶² Again, this will fulfill the Commission’s intent that underlies the entire risk-mitigation framework adopted in D.14-12-025.⁶³

There is a tradeoff inherent whenever a utility’s revenue requirement is authorized based on a future test year, followed by one or more attrition years:

⁶² An example from our recent decision on SCE’s test year 2018 GRC application illustrates the problematic utility approach today, which we intend to address through increased monitoring throughout the GRC cycle. In D.19-05-020 the Commission cited TURN’s testimony regarding SCE’s Service Center Modernization program, which demonstrated “for the past ten years, over the course of three GRC cycles, SCE has repeatedly requested and received significant funding to modernize its service centers, but has not used significant portions of those funds for that purpose. Instead, SCE explains that the funds were ‘reallocated at the corporate level to projects that were deemed more critical for the delivery of safe and reliable service to SCE’s customers.’” D.19-05-020, citing Exhibit SCE-23, Vol. 2 at 16. The Commission noted that SCE’s explanation provided only “one or two sentences that invoke the general principal that ‘utilities must retain flexibility in spending funds authorized in GRC decisions.’” *Ibid.*

⁶³ See, D.14-12-025, Finding of Fact 27 and discussion at 10 and 43.

the 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. Several parties' comments on the PD indicated some uncertainty regarding the Commission's intentions in this respect, and we address those comments here.

For example, TURN's comments on the PD described the benefit TURN sees in a multi-year GRC cycle with only limited attrition year rate adjustments: "[b]y providing the utility a steady revenue requirement over a period of years, based on the Commission's adopted forecast of the utility's cost of service, the utility has a financial incentive to reduce costs during the rate case cycle through process improvements, cost-cutting measures, and increases in efficiencies or productivity."⁶⁴ As TURN observes, this incentive to cut costs works to the benefit of the utility's ratepayers. However, TURN misreads the PD as possibly creating "confusion as to whether the Commission is intending to move away from this framework" as well as suggesting that "the review of a utility's GRC forecasts is somehow less important because of spending accountability reporting requirements."⁶⁵

The utilities, on the other hand, appear to misread the same section of the PD as suggesting the Commission intends to introduce "a rote exercise in which

⁶⁴ TURN Comments on the PD at 4.

⁶⁵ *Ibid.*

utilities are penalized for spending less than an authorized revenue requirement.”⁶⁶ SCE supports moving to a four-year rate case cycle “provided that language is added to the Proposed Decision stating that utilities will receive an attrition year mechanism that fully funds reasonable spending during the three attrition years and avoids funding shortfalls.”⁶⁷

TURN and the utilities need not be concerned, because the PD simply affirms the same ratemaking principles that guide their own approach to, and expectations of, GRCs. To the extent necessary we have modified the PD to clarify that the task we face is how to adhere to these principles in a world where--as all stakeholders can surely agree – events are moving much more quickly than can be accommodated by the existing GRC process.

In such circumstances, the importance of Commission oversight in the midst of a utility’s GRC cycle increases. It is no longer sufficient for the Commission to authorize a multi-year GRC revenue requirement for the utility, and then sit back and wait for the utility and intervenors to report back three years later regarding whether the utility spent the authorized amounts, for specifically authorized purposes, or found it necessary to use the funds elsewhere. Indeed, that is the “rote exercise” described by PG&E, and it is an exercise we find to be less useful as a regulatory tool than it once may have been.

The Commission has always acknowledged that utilities may need to reprioritize spending between GRCs. Now, given the evolving reality we described above, that necessity may even be growing. However, we do not agree with PG&E’s suggestion at the 2017 workshop that one of the necessities of

⁶⁶ PG&E Reply Comments on the PD at 3, emphasis added.

⁶⁷ SCE Comments on the PD, Summary Of Proposed Changes, emphasis added.

moving to a four-year GRC cycle is “stakeholder agreement on the utility’s need to reprioritize.”⁶⁸ Similarly, SCE suggested that adding a fourth year “would assign to the Commission a greater tolerance for forecast error and acceptance of recorded expenses and [capital expenditures] that departed more markedly from authorized levels.”⁶⁹ We disagree with SCE as well.

Lastly, we note that supporters of the three-year cycle such as TURN and, especially, SCE did not rule out further examination of a four-year cycle, albeit on a slower timeline than we adopt in this decision. As we touched upon above, their comments and their earlier workshop presentations offer detailed and well-reasoned analyses of the forecasting, accounting and ratemaking challenges that we believe can be addressed so as to mollify parties’ concerns about moving to a four-year cycle. For example, TURN’s workshop presentation identified challenges such as (1) the added uncertainty inherent in forecasting capital spending for a third attrition year so far in advance; (2) exacerbating the overall risk of relying on outdated forecasts; and (3) the importance, at least initially, of reviewing the implementation of the safety and risk-related S-MAP and RAMP

⁶⁸ See, PG&E presentation at January 11, 2017 workshop, at 3. Available at <https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452101>

In its comments on the PD, PG&E clarifies that it “does not seek *carte blanche* in making reprioritization decisions” and recommends deletion of this reference. PG&E Comments on the PD at 4. We leave the reference intact because the PD addressed a statement by PG&E that is part of the record in this proceeding. However, we note PG&E’s clarification of its position, which shall be our point of reference going forward.

⁶⁹ SCE’s presentation noted that because “the utility industry is going through significant change and there are many emergent issues, forecast error will be magnified and managing the 4th year with authorized revenue requirement may prove challenging.” See, SCE presentation at January 11, 2017 workshop. Available at <https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442462802>

processes more often by retaining the three-year cycle.⁷⁰ As we have just explained, the improved monitoring tools provided by new reporting requirements should directly address the first two concerns listed by TURN. Regarding TURN's third point, the initial implementation of the S-MAP and RAMP processes are now mostly behind us, so we see less need to retain a three-year cycle to enable the more frequent review that TURN suggested at the workshop.

In its comments on the PD, SCE appears to go beyond its prior recommendations, stating it supports moving to a four-year rate case cycle, "provided that language is added to the Proposed Decision stating that utilities will receive an attrition year mechanism that fully funds reasonable spending during the three attrition years and avoids funding shortfalls."⁷¹ SCE proposes adding the following Conclusion of Law:

Each utility in its general rate case will receive an attrition year mechanism that (a) fully compensates the utility for its costs of service in the attrition years, and (b) reflects that circumstances and needs may change over the course of three attrition years, so that the utility's actual spending needs to provide safe and reliable service are addressed during the attrition years.⁷²

In reply comments, TURN opposes SCE's request because it is inconsistent with the purpose of an attrition mechanism, where the Commission has "long affirmed its discretion to grant or deny requests for revenue requirement

⁷⁰ See, TURN presentation at January 11, 2017 workshop, "Summary of TURN's Positions" at 3. Available at <https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452102>.

⁷¹ SCE Comments on the PD, Summary Of Proposed Changes.

⁷² *Id.*, at 4 and Appendix B, emphasis added.

increases in the post-test years through an attrition mechanism.”⁷³ As TURN noted, the Commission has clarified that the annual “attrition adjustment” that it adopts in many, if not most, GRC decisions

is not intended to replicate a test year analysis, or to cover all potential cost changes so as to guarantee [the utility’s] rate of return [during the attrition years],” but “is merely to mitigate economic volatility between test years to a reasonable degree so that a well-managed utility can provide safe and reliable service while maintaining financial integrity.”⁷⁴

TURN’s thorough recitation of the Commission’s history on this issue requires no further amplification. We reject SCE’s request for additional assurances because SCE’s proposed language would inappropriately shift financial risk from the utility to its ratepayers.

Although we have not substantively modified the PD in response to the comments and reply comments of TURN, PG&E and SCE, we do find that further dialog at upcoming workshops would be useful. Parties should discuss and develop recommendations regarding how the Commission should apply the long-standing principles that underlie attrition adjustments to any particular challenges associated with a four-year GRC cycle or emergent issues. We have added this task to the list of topics for future workshops, which we discuss later in this decision.

5.2. Combining PG&E’s GT&S and GRC Proceedings

PG&E is unique among California’s regulated utilities in that its revenue requirements for its gas transmission and storage systems are reviewed in a

⁷³ TURN Reply Comments on the PD at 1-2.

⁷⁴ TURN Reply Comments on the PD at 2, quoting and citing the Commission’s decision in PG&E’s test year 2014 GRC, D.14-08-032 at 652-653.

separate rate case, not part of its GRC. This framework dates back to 1997 when the Commission approved a settlement agreement between PG&E and numerous other parties, labeled the Gas Accord.⁷⁵ The settling parties described the Gas Accord as a “Proposal for a New Gas Market Structure for Northern California.” As adopted, the Gas Accord set PG&E’s gas transmission and storage rates through the end of 2002. The Commission subsequently approved similar settlements known as Gas Accords II, III, IV, and V, which carried the same approach to PG&E’s gas transmission and storage rates forward through 2014. The first fully litigated GT&S rate case was A.13-12-012, which authorized revenue requirements and rates through 2018. Most recently, D.19-09-025 addressed the most recent PG&E GT&S rate case, adopting revenue requirements and rates through 2022.

The Staff Report recommends that PG&E’s GT&S-related rate case requests and its GRC-related requests be submitted in a single application.⁷⁶ Staff acknowledges that a combined GT&S and GRC proceeding for PG&E would result in a “very large” filing, but contends that this would also provide the Commission with a larger perspective on PG&E’s company-wide operations and revenue requirement (with the exception of PG&E’s FERC-regulated transmission system). Staff also recommends that the Commission ensure that additional staff and resources are dedicated to the combined proceeding.

PG&E supports Staff’s proposal to combine the revenue requirement components of its GRC and GT&S rate case proceedings, but requests that the Commission also direct that GT&S rate design and revenue allocation issues be

⁷⁵ D.97-08-055, 73 CPUC 2d, 754.

⁷⁶ Staff Report at 29, Section 7.5.

considered in a separate proceeding, not as part of the GT&S application as is the case today. TURN agrees, and suggests PG&E's periodic gas cost allocation and rate design proceedings as the appropriate forum, because they are similar to the electric GRC Phase 2 proceedings.⁷⁷

We agree that the RCP should be modified to direct PG&E to file a single GRC application that incorporates its GT&S revenue requirement. This change shall be implemented as follows:

Step 1: the Commission addressed PG&E's test year 2019 GT&S application (A.17-11-009) in D.19-09-025 and authorized revenue requirements for 2019-2021. The Commission also added a third attrition year, 2022, and determined that the next test year for PG&E's GT&S will be 2023.⁷⁸

Step 2: in PG&E's pending test year 2020 GRC application (A.18-12-008), PG&E seeks approval of revenue requirements for 2020-2022, so PG&E's next GRC test year will also be 2023.

Step 3: PG&E should initiate its next RAMP proceeding in June 2020, and that filing should examine all the risks that are currently addressed separately in PG&E's GT&S and GRC proceedings.

Step 4: in June 2021 PG&E shall file a single "general rate case" application requesting integrated GRC- and GT&S-related revenue requirements for test year 2023, and three attrition years.

In its comments on the PD, PG&E provided additional detail regarding how to schedule the rate design and cost allocation issues that are traditionally addressed in Phase 2 of the GRC. PG&E notes that the RCP requires utilities to file their Phase 2 application 90 days after the filing of the Phase 1 application, but suggests "[t]his deadline has proven to be unrealistic in recent years."⁷⁹ We

⁷⁷ TURN Comments at 2.

⁷⁸ D.19-09-025, Ordering Paragraphs 2 and 101.

⁷⁹ PG&E comments on the PD at 2, citing D.07-07-004, Appendix A, at A-22.

also clarify that PG&E is not required to file its gas cost allocation applications on any set schedule. On October 24, 2019 the Commission adopted D.19-10-036 in PG&E's 2017 GCAP proceeding. Pursuant to Ordering Paragraph 12 of that decision, PG&E shall file future GCAP applications in three- to five-year cycles.

We agree with PG&E that, because this rulemaking proceeding focused on Phase 1 of the GRCs, we would benefit from a more robust record on whether to modify the filing requirements for Phase 2 applications. As PG&E suggests, we have added that topic to the workshops listed later in this decision. In the meantime, however, D.07-07-004 and D.19-10-036 remain in effect so each utility should follow the procedural vehicles provided in the Commission's Rules if it cannot meet the deadlines required by those decisions.⁸⁰

5.3. Moving the Due Date for the Public Advocates Office's Opening Testimony

The Staff Report recommends that the Commission modify the RCP schedule established in D.14-12-025 to move the due date for the Public Advocates Office's testimony from February 20th to "early April" of the year prior to the test year.⁸¹ The Staff Report demonstrated that the February deadline is not realistic, because the Public Advocates Office simply cannot complete its comprehensive review of the utility application by that date. Staff agrees that a later date is needed to give the Public Advocates Office sufficient time to complete discovery and prepare its testimony.⁸²

⁸⁰ Our direction here is consistent with SCE's comments on the PD (at 7-8), which assume the timing for the filing of the Phase 2 application remains 90 days after the GRC Phase 1 application is filed.

⁸¹ Staff Report at 24, Section 7.1.

⁸² In its comments on the Staff Report, the Public Advocates Office notes that it actually requested a later due date in April, approximately mid-month, not the first of the month as Staff recommends. Public Advocates Office Comments at 3-4.

Other parties offer qualified support for an April due date. First, PG&E recommends that the Commission make an additional modification to the RCP so that the IOUs' approved revenue requirements become automatically effective on January 1st of the test year, regardless of when the Commission issues its final decision on the application.⁸³ Second, SCE emphasizes that a revised April deadline must be considered a firm date for receiving the Public Advocates Office's testimony, "rather than a new starting point from which [the Public Advocates Office] can readily seek additional extensions."⁸⁴ Third, SDG&E and SoCalGas recommend that if the Public Advocates Office's due date is moved to April 1st, then all intervenors should serve testimony no later than April 21 as Staff proposed: "[t]he Rate Case Plan should always attempt to conclude a GRC application before the Test Year begins."⁸⁵

We agree that the RCP schedule adopted in D.14-12-025 should be modified to provide the Public Advocates Office with additional time to prepare and serve its testimony. The Public Advocates Office's testimony and recommendations are an indispensable element of all energy utility GRCs, which the Commission relies upon extensively as part of its own evaluation of a utility's requests. The Public Advocates Office is usually the only party that offers a complete alternative to the utility's requested revenue requirement, meaning that the Public Advocates Office runs the RO model based on its own recommendations and calculates its recommended revenue requirement in the

⁸³ PG&E Comments at 6. Under current Commission practice, the utility must formally request this authorization, and the Commission addresses the request in a stand-alone decision early in the proceeding.

⁸⁴ SCE Comments at 3.

⁸⁵ SDG&E and SoCalGas Comments at 1.

same format as presented in the utility's application and testimony (*e.g.*, operation and maintenance expenses, depreciation expenses, tax expenses and return on ratebase). This provides the Commission with a fully realized alternative to consider. The other intervenors typically lack the resources of the Public Advocates Office and generally cannot evaluate the entire utility request. Instead, they focus on specific issues and do not present an alternative total revenue requirement as the Public Advocates Office does. This more-focused intervenor testimony is no less helpful to the Commission, but our point here is that any changes to the RCP schedule should be supportive of the Public Advocates Office's task.

The revised RCP schedule we adopt in this decision provides the additional time the Public Advocates Office requests. We also agree that the Public Advocates Office should treat this date as a firm deadline that is unlikely to be extended in future GRC proceedings. Indeed, having granted the Public Advocates Office's request here, we do not expect they will seek extensions in future proceedings.

Several parties suggested in their comments or reply comments on the PD that the RCP schedule could also be revised to require that all intervenor testimony be served on the same day as the Public Advocates Office, rather than several weeks later as is the case today.⁸⁶ TURN provides a useful discussion of the pros and cons of eliminating the staggered deadlines, from the perspective of the intervenors. On balance, we find that moving to a single due date for the Public Advocates Office and intervenor testimony will improve the overall

⁸⁶ TURN Comments on the PD at 6-7, PG&E Reply Comments on the PD at 3, SCE Reply Comments on the PD at 3.

efficiency of future GRCs. We are somewhat more optimistic than TURN that all parties will be able to coordinate their testimony as needed, and we note that the GRC record also typically includes a joint comparison exhibit that compares the positions of parties. Therefore, this modification of the RCP schedule is included in the revised schedule adopted in this decision.

We do not adopt PG&E's request to modify the RCP to provide that a utility's GRC application shall automatically have an effective date of January 1 of the test year. Every GRC application has its own unique aspects, and we should maintain the flexibility to approve effective dates with consideration of whatever circumstances may present themselves during any particular GRC proceeding.

5.4. Adopted Revisions to Rate Case Plan

Having addressed the three recommendations in the Staff Report that directly affect the RCP schedule for future GRCs, we turn our attention back to the generic schedule we outlined earlier in this decision. That schedule demonstrated that we can satisfy the scheduling requests of the applicant utility, the Public Advocates Office, and the other intervenors if we move the filing date for the utility GRC application to May 15 of the year falling two years prior to the test year. Each of the three modifications we have just adopted will still work in that modified schedule. Therefore, in this decision we adopt the revised RCP schedule shown in Table 3 below.

In adopting the May 15th filing date, we modify the PD's choice of a March 1 filing date. Parties' comments on the PD explained clearly why the March 1 deadline would prevent the utilities from including complete spending data from the previous calendar year. The utilities stated they would prefer a June 1 filing date in order to incorporate this data. TURN initially suggested a

May 1 deadline in its comments on the PD. In reply comments, TURN notes that it does not oppose a June 1 filing date, but observes that if the Commission adopts that date, and leaves unchanged the number of days provided for the Public Advocates to complete its testimony, the most reasonable place to adjust the PD's RCP schedule is in the number of days provided for the ALJs to prepare the proposed decision: "If the utilities are willing to accept this risk, TURN does not oppose a June 1 GRC filing."⁸⁷

We adopt a May 15 filing date because, while it is two weeks earlier than the utilities prefer, it allows the remainder of the schedule to unfold in a manner that enables the Public Advocates Office (and, as explained below, all other intervenors) to serve their testimony in mid-December, rather than in January, as all parties suggest is preferable. The utilities' schedule would also reduce the period of time for preparation of the PD so much that one of our goals for the revised RCP, a final decision before the test year begins, would likely remain out of reach.

The revised schedule also clarifies the language in the PD regarding RAMP filing dates and procedures, as recommended by SCE.⁸⁸ The RAMP proceedings shall now be initiated by the utility filing an application (including the RAMP report itself) which may then be categorized as a ratesetting proceeding. As noted in the PD, this will create additional time for SED and parties to complete their review of the utility's RAMP farther in advance of the subsequent GRC filing date, so that the utility has as much time as possible to meaningfully incorporate the results of this review in its GRC application.

⁸⁷ TURN Reply Comments on the PD at 3-4.

⁸⁸ SCE Comments on the PD at 8-9.

Table 3
Adopted Revised GRC Application Filing Schedule
Effective June 30, 2020

Date	Days	Event
Test Year minus-3		
May 15	Day 0	Utility files application to initiate its RAMP proceeding
By September 1	~Day 110	SED files and serve report on utility's RAMP submission.
By November 15	~Day 184	Opening comments on RAMP submission and the SED report
By December 1	~Day 200	Reply Comments
Test Year minus-2		
May 15	Day 0	Utility files GRC application, and serves prepared testimony
By May 30	~Day 15	Utility holds public workshop on overall GRC application
30 days after Daily Calendar notice	~Day 30	Due date for protests and responses to GRC application, pursuant to Rule 2.6(a)
By June 30	~Day 45	Prehearing Conference held
By August 15	~Day 90	Scoping Memo of Assigned Commissioner issued
To be decided		Public Participation Hearings
By December 15	~Day 215	Public Advocates Office and other intervenors serve opening testimony
Test Year minus-1		
By January 30	~Day 260	Concurrent rebuttal testimony served
By February 25	~Day 285	Evidentiary hearings begin
By March 15	~Day 305	Evidentiary hearings end
To be decided		Update testimony and hearings, if necessary
By April 20	~Day 340	Briefs filed
By May 12	~Day 360	Reply briefs filed
By August 3	~Day 445	Status conference, proceeding submitted for Commission decision [Rule 13.14(a)]
By November 1	~Day 535	Proposed decision mailed for comment
By December 1	~Day 565	Final decision adopted
Test Year		
January 1	~Day 595	Effective date of final decision

The revised schedule adds specific dates to areas labeled “to be determined” in the D.14-12-025 schedule, and also incorporates several simple schedule modifications proposed by parties that we agree will help GRCs proceed more efficiently. First, the “kick-off” workshop required of the applicant

utility will take place within 2 weeks of the filing. Workshop participants appeared to agree that this workshop provides a useful and effective opportunity for the applicant to explain its application and respond to clarifying questions from parties. Second, the Prehearing Conference will be scheduled no later than two weeks after the due date for protests and responses to the GRC application. This should also ensure that the Scoping Memo is issued in a timely manner.

We also note the revised schedule breaks the linkage between the submittal date and the date reply briefs are filed. Rule 13.14 (Submission and Reopening of Record), part (a) provides that “[a] proceeding shall stand submitted for decision by the Commission after the taking of evidence, the filing of briefs, and the presentation of oral argument as may have been prescribed.” Pub. Util. Code § 311(d) requires that the proposed decision of the assigned ALJ or the assigned commissioner shall be issued not later than 90 days after the matter has been submitted for decision. Our recent experience indicates that 90 days is not enough time for the ALJs to draft a lengthy GRC proposed decision and to complete the RO modeling that calculates the resulting revenue requirement. Setting the submittal date several months after reply briefs are filed will allow the ALJ to begin drafting the PD upon receipt of briefs, but still leave a realistic period of time for the RO modeling. For this reason, the revised schedule includes a new milestone, a status conference that would take place approximately two months after filing of reply briefs. The status conference will provide an opportunity for the ALJ and the assigned Commissioner to obtain additional information that may assist in completion of the PD. Although the proceeding record would remain open until the status conference, protocols should be established at the outset of every proceeding to ensure that additional

evidence would be taken at the status conference only under well-defined circumstances.⁸⁹

Parties' comments on the PD included many suggestions regarding implementation of the transition to the four-year cycle in the years ahead. The PD noted that the next utility scheduled to initiate its RAMP proceeding is PG&E, in 2020, and stated that the revised schedule should apply to PG&E to avoid delaying combination of PG&E's GT&S and GRC for another GRC cycle.

In its comments on the PD, PG&E proposed a schedule where it would initiate its RAMP proceeding on June 30, 2020.⁹⁰ Similarly, PG&E proposes a June 30, 2021 deadline for its 2023 GRC application.⁹¹ After this one-cycle-only accommodation to allow PG&E to file its RAMP and GRC applications later than the dates adopted in this decision, PG&E would make these filings on May 15 in future GRC cycles.⁹²

We adopt PG&E's suggested schedule in this decision. We note that the Commission's recent GT&S decision authorized an additional attrition year, so PG&E's next GT&S test year will be 2023. PG&E's current GRC application (A.18-12-009) is based on a 2020 test year and two attrition years (2021 and 2022), so that proceeding can be concluded with no modifications to scope or schedule.

⁸⁹ In their comments on the PD (at 11-12), SDG&E and SoCalGas raise concerns about the status conference and the application of Rule 13.14. The PD anticipated and addressed the issues they raise regarding use of this milestone for anything other than facilitating preparation of the PD. In addition, Rule 13.14(a) in its entirety provides that "[a] proceeding shall stand submitted for decision by the Commission after the taking of evidence, the filing of briefs, and the presentation of oral argument as may have been prescribed" (emphasis added). SDG&E and SoCalGas omit the underlined qualifier, incorrectly suggesting that the PD could lead to an outcome inconsistent with Rule 13.14 and other due process concerns.

⁹⁰ PG&E Comments on the PD at 5-6.

⁹¹ *Id.* at 6.

⁹² *Id.* at 8-9.

For SoCalGas and SDG&E, the PD found that the three-year GRC cycle authorized in D.19-09-051 should be implemented as adopted. The next GRC cycle for those utilities' would be initiated with their RAMP proceedings in November of this year, followed by each utility filing a three-year GRC application in September 2020, for 2022 test years. In comments on the PD, SoCalGas and SDG&E cite the Commission's direction in D.19-09-051 where it declined to authorize a 2022 attrition year for each utility, but stated "If a decision adopting a four-year GRC cycle is made in R.13-11-006, Applicants shall file a petition for modification of this decision."⁹³

In consideration of D.19-09-051, we have revised the PD with some necessary adjustments to ensure a pragmatic rate case schedule for parties and Commission staff. Although SoCalGas and SDG&E suggested that we require PG&E to propose a third attrition year in its current GRC proceeding, we decline to do so because that proceeding is nearing its conclusion. Instead, we direct SoCalGas and SDG&E to request two additional attrition years (2022 and 2023) in their petition for modification of D.19-09-051 in order to avoid having their next GRCs filed in the same year as PG&E in 2021. 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

⁹³ In their respective GRC applications filed in 2017 SoCalGas and SDG&E each requested authorization for a third attrition year. The Commission addressed these applications in D.19-09-051. In Ordering Paragraph 33 of D.19-09-051 the Commission directed that if a decision adopting a four-year GRC cycle is adopted in this Rulemaking, SoCalGas and SDG&E "shall file a petition for modification of this decision" to request review and implementation of their post-test year proposals for 2022.

capital projects for 2022 and 2023, and updates to all relevant forecasts from their 2019 GRC applications. The petition filed by SoCalGas and SDG&E should also address the interaction between this decision and their respective RAMP proceedings. We note that both utilities incorporated the results of their 2016 RAMP proceedings (I.16-10-016 and I.16-10-015, respectively) into their 2019 GRC applications. Those results informed each utility's forecasted requests for test year 2019 operations and maintenance expenses and 2017-2019 capital investment (*see*, I.16-10-015 and I.16-10-016, March 5, 2018 Motion of SDG&E and SoCalGas to close their RAMP proceedings, at 5). Furthermore, the Commission recently opened I.19-11-010 and I.19-11-011 for SoCalGas and SDG&E, respectively, which as-filed are intended to support test year 2022 GRC forecasts by each utility. Now that this decision has designated 2022 and 2023 as additional attrition years in the 2019 GRCs and the next GRC test year for SoCalGas and SDG&E will be 2024, their 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.

In summary, as described above PG&E's next GRC application will be filed in 2021, for a 2023 test year and three attrition years. SoCalGas and SDG&E will follow in 2022 with their applications for 2024 test years and three attrition years. Lastly, in order to accommodate the timing for PG&E, SoCalGas and SDG&E, SCE should file its next GRC application in 2023 for a 2025 test year and three attrition years. We note that this schedule will necessitate that SCE amend its current GRC proceeding, A.19-08-013, to add a third attrition year. Compared

to PG&E, it is early enough in SCE's proceeding to accommodate a transition from a three-year to a four-year GRC cycle. We will defer to the assigned Commissioner and Administrative Law Judges for A.19-08-013 to determine the appropriate schedule for that additional attrition year.

Table 4 below provides a higher level summary of the transition from the current three-year cycle to the four-year cycle, including the scheduled filings for PG&E, SCE, SoCalGas, and SDG&E. The forward-looking portion of this schedule is provided in Appendix B to this decision. We note that with the combination of PG&E's GT&S and GRC filings into a single application, the pattern of three utilities filing on a four-year cycle will result in no GRC being filed every fourth year.

Table 4
Schedule for the Transition from the
Current Three-Year GRC Cycle to the Four-Year GRC Cycle

Filing Date	PG&E	SCE	SDG&E and SoCalGas
September 1, 2015	GRC: A.15-09-001 • 3-year cycle • Test Year: 2017 • Attrition Years: 2018-2019		
September 1, 2016		GRC: A.16-09-001 • 3-year cycle • Test Year: 2018 • Attrition Years: 2019-2020	
October 27, 2016			RAMPs: I.16-10-015 & I.16-10-016
October 6, 2017			GRCs: A.17-10-007 and A.17-10-008 • 3-year cycle • Test Year: 2019 • Attrition Years: 2020-2021
November 9, 2017	RAMP: I.17-11-003		
November 17, 2017	GT&S: A.17-11-009 • 4-year cycle • Test Year: 2019 • Attrition Years: 2020-2022		
November 8, 2018		RAMP: I.18-11-006	
December 13, 2018	GRC: A.18-12-009 • 3-year cycle • Test Year: 2020 • Attrition Years: 2021-2022		
August 30, 2019		GRC: A.19-08-013 • Test Year: 2021 • Attrition Year: 2022-2023	
November 7, 2019			I.19-11-010 and I.19-11-011 opened for SDG&E and SoCalGas RAMPs
For SDG&E and SoCalGas: as soon as practicable For SCE: As directed		SCE shall amend A.19-08-013 to propose an additional attrition year for 2024, as directed	SDG&E and SoCalGas shall file Petitions for Modification of D.19-09-051 to add 2022 and 2023 attrition years
By June 30, 2020	Files 2023-2026 RAMP application		
May 15, 2021			SDG&E and SoCalGas shall file 2024-2027 RAMP applications
By June 30, 2021	<u>Files combined GRC/GT&S application:</u> • 4-year cycle • Test Year: 2023 • Attrition Years: 2024-2026		
May 15, 2022		Files 2025-2028 RAMP application	<u>Files next GRC application:</u> • 4-year cycle • Test Year: 2024 • Attrition Years: 2025-2027
May 15, 2023		<u>Files next GRC application:</u> • 4-year cycle • Test Year: 2025 • Attrition Years: 2026-2028	

5.5. Additional Workshops

In addition to the specific recommended modifications to the RCP that we addressed above, the Staff Report also recommends that the Commission direct the Energy Division to host additional workshops to further examine a number of ideas raised by workshop participants regarding how to further standardize GRC filings and streamline the GRC process.⁹⁴ The Staff's recommendations for workshops and schedules are summarized below:

	Energy Division Staff-Recommended Workshops	Proposed Scheduling
1	Standardizing GRC filings	3 months after this decision is issued
2	RO model uniformity	6 months after Workshop #1
3	Stipulated terms or rebuttable presumptions	6 months after Workshop #2
4	FERC accounting	To be determined

Each of the parties that addressed Staff's recommendations supported the general idea of more workshops, though not necessarily the specifics.⁹⁵ SCE offers useful suggestions regarding advance preparations by Commission staff to ensure that the workshops are efficient uses of parties' time and result in recommendations that are helpful to the Commission. SCE suggests that Commission staff meet "off-line" with each of the stakeholders prior to preparing workshop agendas, and circulating initial substantive proposals for review and comment in advance of each workshop.⁹⁶

We appreciate the willingness of parties to continue to work together to improve GRC proceedings. We also agree with SCE's general recommendation

⁹⁴ Staff Report at 25, Section 7.2.

⁹⁵ PG&E Comments at 9; SCE Reply Comments at 2; SDG&E and SoCalGas Comments at 1; TURN Comments at 2.

⁹⁶ SCE Reply Comments at 2.

that the workshop process be structured in a way that makes good use of stakeholders' time and leads to further efficiencies and improvements in GRCs. Parties also offered thoughtful analysis of the detailed workshop proposals in the Staff Report, agreeing with some and opposing others. Our discussion below benefits from that analysis. As will be seen, our adopted plan for further workshops will address fewer issues than recommended by Staff, and do so in a somewhat shorter period of time.

5.5.1. Should a Future Workshop Address Standardizing GRC Filings?

Staff suggests in the workshop report that if each of the energy utilities followed uniform filing standards when preparing their applications, the Commission could process the applications more efficiently, and would also find it easier to directly compare revenue requirements across utilities. Staff also envisions that standardized filings would reduce the need for staff to develop utility-specific expertise. For these reasons, the Staff Report recommends that a workshop be held to address the topic of standardizing GRC filings, with a focus on four sub-topics:

1. Data Request Format: development of a standard process and format for all data requests sent to the utility, whether originated by intervenors or Commission staff [Master Data Request]
2. Joint Comparison Exhibit (ICE): development of a standard process and format to be used by all utilities, for use by the Commission in reviewing issues in the proceeding
3. Standard Index for Testimony: discussion of whether the utilities and other parties should prepare testimony using standardized chapter numbers that always reference the same class of expenses.
4. The Base Year and Requirements Regarding Recorded Data: stakeholders would explore whether the Commission should change the base year of a GRC, and how the Commission can

formally include the recorded spending data from the year of filing into the records of the GRC proceedings.⁹⁷

5.5.1.1. Data Request Format

SCE supports adopting a form of Master Data Request that would be useful to the Staff from different Commission divisions. In addition to the workshop-type exploration that Energy Division recommends, SCE suggests that each utility host a meeting with Commission Staff and GRC parties before the utility files its GRC application. At such meetings, the utility could gather and synthesize similar inquiries from parties and staff, and thereby provide more comprehensive responses on a more efficient basis.⁹⁸

SDG&E and SoCalGas agree that the Master Data Request used in GRC proceedings should be standardized to the extent possible.⁹⁹

We agree that stakeholders should develop and utilize a standard data request format, and this is a good example of a matter that would benefit from “off-line” development prior to any workshop, as SCE recommended in its reply comments. We do note some confusion in terms regarding whether this recommendation relates (1) solely to the so-called “master data request” that is sometimes a feature of utility applications and is filed at the same time as the application and testimony, or (2) to all discovery requests in a GRC proceeding, from intervenors to the applicant, and vice versa. We prefer that parties reach

⁹⁷ The Staff Report explains at 10 (footnote 15): “[w]hen a utility files a GRC, the utility needs to include recorded spending data from the most recent year in its filing to justify the forecasted costs in the test year. This year of recorded spending data is called the base year.” With a three-year GRC cycle, the base year of recorded data for a future GRC filing is the test year of the last GRC filing.

⁹⁸ SCE Comments at 9.

⁹⁹ SDG&E and SoCalGas Comments at 2.

agreement on the broadest scope and the most standardization that can be reasonably achieved. From the Commission's standpoint, especially when discovery disputes arise or an "off-line" dispute is referenced by parties during hearings, it is important to be able to clearly and consistently determine the following information at a glance, rather than spend time in hearings doing so:

- The party and witness that originated the data request;
- The date of the data request, and the requested response date;
- The actual response date, including whether any extensions were negotiated and, if so, when and by whom; and
- The name of the witness sponsoring the response.

Finally, workshop discussions about master data requests should include their use in each utility's RAMP proceeding. For example, if SED's review of the RAMP filing could benefit from use of a standardized and obligatory master data request, the format and questions should be developed at the future workshop or workshops discussed later in this decision.

5.5.1.2. Standardized Joint Comparison Exhibit

SCE supports exploration of adopting a standardized form of the JCE, where parties would continue to contribute to the JCE by providing their specific inputs into the JCE, which is then compiled by the applicant utility.¹⁰⁰ SDG&E and SoCalGas agree that the JCEs used in GRC proceedings should be standardized to the extent possible.¹⁰¹

We note that a JCE is not prepared in every GRC; rather, in each proceeding its necessity is discussed and resolved by the assigned

¹⁰⁰ SCE Comments at 9.

¹⁰¹ SDG&E and SoCalGas Comments at 2.

Commissioner, ALJ, and the parties. We see value in devoting workshop time to reaching agreement on a standard format because this would help the assigned Commissioner and ALJ decide early in the proceeding whether to require parties to prepare a JCE at all. We also note that in past GRCs the JCEs that were useful to us as we made our decisions were those that clearly show the differences between parties, especially in summary form, while also providing specific citations to testimony for those reviewers needing or wanting to delve deeper into the details of parties' positions. We also direct parties to discuss the feasibility of preparing, prior to evidentiary hearings, a summary of positions on contested issues in order to provide the assigned Commissioner and ALJ with a "roadmap" to assist in efficiently conducting the hearings.

5.5.1.3. Standard Index for Testimony

Parties did not address this recommendation in their comments, but we agree that a standardized index would be helpful and should be developed prior to, and finalized during, the workshops we endorse in this decision. In every GRC, the Commission's essential task is identical: to authorize the level of funding necessary for the applicant utility to provide safe and reliable service at just and reasonable rates. However, each GRC that comes before the Commission is likely to be overseen by different assigned Commissioners and ALJs, so a standardized presentation of each applicant's request will assist the Commission as a whole to understand the issues in any given GRC.

Given the importance to the energy utilities of having an approved revenue requirement prior to the beginning of the test year, it is in their self-interest to make it as easy as possible for every Commissioner, not just the assigned Commissioner who is most familiar with the proceeding, to evaluate the requests of any utility in any GRC. By presenting their testimony according

to a common outline, and using consistent terminology and standard table formats, the utilities will ease the work of the Commission.

Standardization should also be extended to the utilities' RAMP filings, which will assist SED and parties in their review. A standard format should be developed for mapping RAMP risk mitigations to GRC testimony and workpapers. GRC workpapers should also indicate which costs are RAMP-related costs, and which are non-RAMP-related. We include these topics in our list of workshop topics at the end of this decision.

5.5.1.4. The Base Year and Requirements Regarding Recorded Data

SDG&E and SoCalGas agree that use of base year recorded data in GRCs should be addressed to determine where it might be practical to standardize. However, they also note that "while utilities can provide the recorded data, it would not be efficient to retrofit back to workpapers and models, nor provide 'updated' spreadsheets with the Base Year +1 data."¹⁰²

Agreement on a standard approach to "Base Year +1 data" should be an important topic for future workshops. Stakeholders should endeavor to reach consensus on a means of incorporating this data into every GRC on an agreed-upon schedule. For example, in the recently concluded SCE 2018 test year GRC, the base year was 2015. However, during the proceeding SCE was able to update its recorded spending data in its June 2017 rebuttal testimony to include all of 2016 (i.e., "Base Year +1). It is neither surprising nor alarming that the recorded 2016 data was often very different from the corresponding 2016 forecasts included in SCE's September 2016 application. The Commission's

¹⁰² *Ibid.*

decision-making benefited from having the recorded 2016 data available because of the improved accuracy, so that should be considered a standard milestone in every energy GRC.

5.5.2. Should a Future Workshop Address Stipulated Terms, Rebuttable Presumptions, and Formula-Based Attrition Year Revenue Requirements?

The Staff Report explains that some parties at the workshop proposed that the Commission could process GRC applications more quickly if it considered adopting stipulated terms, such as using multi-year averages of historical spending for certain common or predictable expenses, or rebuttable presumptions for certain “base operation” expenses:

In its presentation, SCE suggested that the Commission adopt stipulated terms for certain “base operation” expenses, particularly expenses for activities that can be forecasted using multi-year averages. During discussions, TURN also suggested that the Commission adopt certain expenses under rebuttable presumptions to reduce the amount of litigated issues in a GRC. For example, the Commission could employ a rebuttable presumption that base year plus inflation is adequate for general operational, maintenance, and administrative expenses that are not funding new programs.¹⁰³

The Public Advocates Office expressed more caution regarding these suggestions. The Staff Report suggests that a workshop examine whether the Commission can adopt stipulated terms or rebuttable presumptions without compromising its ability to determine whether the funding requests are just and reasonable. The workshop could consider not just whether the Commission

¹⁰³ Staff Report at 19. To ensure parties have a common understanding of this proposal, we provide the following definition of a rebuttable presumption: “a presumption which is not conclusive but may be overcome by opposing evidence.” Accessed online at Ballentine's Law Dictionary, LexisNexis, July 11, 2019.

could adopt certain test year expenses under stipulated terms or rebuttable presumptions, but also whether attrition year revenue requirements could be determined based upon rebuttable presumptions such as a standard escalation formula, or “an incentive ratemaking mechanism for the attrition years based on the utility’s return on equity or return on rate base.”¹⁰⁴

In its comments, SCE agrees that workshops are warranted “to ascertain if the Commission can adopt stipulated expenses, or rely upon rebuttable presumptions” to help streamline the processing of GRCs.¹⁰⁵ SDG&E and SoCalGas generally agree as well, while noting that “there are already procedures for stipulations, and areas parties typically can stipulate are often non-controversial.”¹⁰⁶ SDG&E and SoCalGas also indicate that they require more details about how rebuttable presumptions and incentive ratemaking for attrition years might add value or be pursued in the GRC context.¹⁰⁷

TURN encourages the Commission to expedite the consideration of these topics in a workshop: “[g]iven the work already done by staff and parties to identify these potential GRC policy changes to streamline the processing of GRCs (where feasible), TURN submits that it would be a shame to delay the benefits...” of reduced litigation in GRCs and more efficient GRC proceedings.¹⁰⁸

We agree with TURN that a workshop should be held as soon as reasonably practicable to further refine the recommendations at the 2017 workshop and in the 2018 Staff Report regarding approaches that could reduce

¹⁰⁴ Staff Report at 20 and 26.

¹⁰⁵ SCE Comments at 7.

¹⁰⁶ SDG&E and SoCalGas Comments at 2.

¹⁰⁷ *Ibid.*

¹⁰⁸ TURN Comments at 3.

the number of litigated issues. To our mind, this topic differs somewhat from the stipulations referenced by SDG&E and SoCalGas, which are common in GRCs but also unique to an issue or a stakeholder's interest in that particular proceeding. Instead, the workshops directed in this decision should focus on building a framework for the utility's initial showing that rests upon stipulated approaches to escalating capital expenditures or operating expenses, or rebuttable presumptions about the same test year operating expense forecasts. This framework could become common to every GRC, for every utility.

Regarding the matter of formula-based attrition year revenue requirements, this is already the typical approach to the operating expense portion of the revenue requirement, which is determined by applying a range of escalation factors to specific expense categories within the adopted test year forecast. Greater efficiencies in this area would clearly result if agreed-upon stipulations or rebuttable presumptions were in place at the outset of a proceeding. We are more cautious about implementing such an approach to the capital expenditure portion of attrition year revenue requirements. We do not intend to adopt an approach that places such increases on "autopilot" for three years out of every four-year GRC cycle – the long-term impact of capital investments on customer rates warrants a closer look at the attrition year changes and ongoing monitoring by Commission staff via the reporting requirements introduced by D.14-12-025, especially at a time when the utilities seek "stakeholder agreement on the utility's need to reprioritize" as PG&E suggested at the 2017 workshop.

5.5.3. Should a Future Workshop Consider Greater Uniformity in the Results of Operation Model?

The Staff Report recommends that a future workshop explore ways to make the RO models of the four utilities more uniform and user-friendly, including the following (ranked from easiest to most difficult):

1. Developing a standard format for the Summary of Earnings table, which is usually a single table that shows the major components of the applicant's requested revenue requirement, and at the end of the proceeding, the amounts authorized by the Commission (e.g., operating expenses, depreciation expenses, tax expenses, and return on rate base);
2. Developing a user-friendly input interface for the RO model, to enable a user without extensive RO modeling training to enter inputs into the model to calculate the revenue requirement; and
3. Developing a uniform RO model format or structure so that they would be more consistent across the utilities and, presumably, easier for the Commission and others outside the utilities to understand.

The utilities' comments in response to these recommendations note that the first item listed above would be simple to develop, while the second would be more difficult and of questionable value to our effort to streamline GRC proceedings, and the third item would be "extremely challenging"¹⁰⁹ and (in our own view, as well) not justified by the effort involved.

The Commission relies on RO models for purposes that lead us to suggest that a different list of refinements should be undertaken in order to help the Commission issue GRC decisions more quickly. First, our overarching concern is that the RO results and revenue requirement that is included in the ALJ's

¹⁰⁹ PG&E Comments at 9.

proposed decision is accurate. It is also important that parties trust that the calculation is accurate, no matter who does that calculation. Furthermore, given the time pressures at the end of GRC proceedings it is very important to the Commission that the actual task of preparing the RO calculations proceeds smoothly. As has been typical in recent years, we have no problem relying on the utilities to prepare the RO for the PD and the final Commission decision, albeit with Energy Division oversight and a non-disclosure agreement in place. The utilities know their own models best, which ensures as accurate a calculation as possible, and the penalties they would incur for violating our trust and manipulating the results far outweigh any potential gain. However, the “typical” process could be improved in a way that would result in more timely GRC decisions. In future GRCs, under Energy Division oversight and with the same non-disclosure agreements in place, each utility should begin working with the Energy Division as soon as possible in the PD drafting process and incorporate the ALJ’s determinations as they are made instead of waiting for a completed written draft of the entire proposed decision before beginning the RO work. The future workshops would provide an opportunity for the utilities to explain their perspectives and develop a single approach to their working relationship with the ALJ and Energy Division staff, to be used by all utilities in all GRCs going forward. This would improve the predictability of this stage of preparing the PD.

Furthermore, as noted above, in most large energy GRCs the Public Advocates Office is the only party that performs RO modeling independently of the utility applicant. We hope this practice continues. The Public Advocates Office can make its own needs clear in the upcoming workshops, but we indicate here that we prefer that any reasonable needs expressed by the Public Advocates

Office are heeded and accommodated by the utilities. For example, if the Public Advocates Office believes the RO models are becoming too complex, the utilities should pay close attention to their recommended solutions. Similarly, if *any* intervenors can demonstrate the value of greater standardization at either the “input” stage or the “output” stage than we have endorsed here, the utilities should consider those recommendations. Any refinements that ease the burden on GRC parties are likely to translate into greater efficiencies for the Commission’s decision-making as well.

Our final item regarding the RO model is one that was not mentioned in the Staff Report or parties’ comments: bill impacts. Each utility currently includes summary-level bill impacts for a residential customer in its GRC application, but only for one “average” usage level, and without differentiating by usage in various climate zones, or other means, in the utility’s service territory.¹¹⁰ The Energy Division should include the task of incorporating standardized bill impact calculations into every GRC application as a mandatory topic at the future workshop(s). The utilities should consider this to be a compliance item imposed on each of them by this decision.

5.5.4. Should a Future Workshop Address FERC Accounting?

The fourth and final workshop recommended in the Staff Report would further explore the benefits and costs of requiring the utilities to present their GRC requests in a format that conforms to the corresponding FERC accounting

¹¹⁰ See, for example, A.18-12-009, PG&E’s application for authority to increase rates and charges for electric and gas service effective on January 1, 2020, at 5, Table 2, “Impact on Non-CARE Residential Typical Customer Bills.”

structure.¹¹¹ Staff explains that requiring utilities to present their GRC in this manner would enable the Commission and parties to more easily compare costs across the four utilities, as well as to utilities across the country that are also required to report this data in annual FERC Form 1 and Form 2 filings.

The Staff Report acknowledges that workshop participants expressed widely different opinions about whether the Commission should adopt this requirement. Staff suggests the recommended workshop would provide an opportunity to address this question in greater depth.

As Staff anticipated, the utilities uniformly oppose the idea of presenting their GRC applications using the FERC Uniform System of Accounts, or even scheduling a workshop to discuss the idea further. SDG&E and SoCalGas explain succinctly what PG&E and SCE state in greater detail: “[a]lthough standardization of accounting systems across all utilities for GRC purposes might seem to be a desirable goal, use of the FERC system of accounts would not be feasible or realistic, as all the utilities are very different.”¹¹²

¹¹¹ As the FERC explains on its website, it is “responsible for the accounting and financial reporting of its jurisdictional companies. This is accomplished through the development and maintenance of the Commission's Uniform System of Accounts” which “provides basic account descriptions, instructions, and accounting definitions” that the FERC describes as useful in understanding the information reported in electric utilities’ annual reports to the FERC, which are commonly known at the “FERC Form 1.”

<https://www.ferc.gov/enforcement/acct-matts/usofa.asp>

In turn, the FERC describes its Form 1 as “a comprehensive financial and operating report submitted annually for electric rate regulation, market oversight analysis, and financial audits by major electric utilities.” <https://www.ferc.gov/docs-filing/forms.asp?new=sc1#1>

Our record is unclear regarding whether the FERC requires similar standardized accounting by natural gas distribution companies.

¹¹² SDG&E and SoCalGas joint Comments at 3. *See also* PG&E Comments at 9-10 and SCE Comments at 6-7.

The utilities have convinced us that requiring them to present their GRC requests in a format based on FERC accounts would be inadvisable and would not result in greater efficiencies or streamlining of the GRC process. That said, one takeaway for the utilities from our discussions above should be the importance we place on having information available to us that allows us to compare the utilities with each other on an “apples-to-apples” basis. If the FERC accounting framework is not the best means of accomplishing this goal, we expect the utilities to suggest a better approach. Once again, though it may not seem evident to the utilities, our review of any particular GRC application can be completed more quickly if all the applications are presented to us in a common format.

5.5.5. Adopted Workshop Topics and Schedule

As we said earlier in this decision, we embrace any changes to the RCP that will help us process GRCs more efficiently. The same goes for future workshops. Parties’ comments on the Staff Report have helped us narrow the list of topics that should be considered in workshops to those where parties indicated success is likely. On that basis, we direct Staff to schedule one or more workshops to address the topics listed below. We leave it up to Staff, working collaboratively with parties at the planning stage as SCE suggests in its comments, to organize the details.

We would welcome parties’ suggestions for improvements in the following broad areas:

1. Standardizing the organization and format of GRC and RAMP filings and the proceeding record, including the possibilities offered in the Staff Report:
 - a. Developing and recommending a standard index for testimony;

- b. Developing and recommending a standard format for mapping RAMP risk mitigations to GRC testimony and workpapers. GRC workpapers should also indicate which costs are RAMP-related costs, and which are non-RAMP-related;
 - c. Developing and recommending a standard data request format, including for the RAMP, as we discussed in Section 5.5.1 above;
 - d. Developing and recommending a standard format for the Joint Comparison Exhibit; and
 - e. Developing and recommending general ground rules regarding identification of the Base Year, as well as a common framework for incorporating updated “Base Year +1” recorded data at a given stage of the GRC proceeding.
2. Discussing and developing recommendations regarding the possible use of stipulated terms, rebuttable presumptions, and escalation-based attrition year revenue requirements. We clarify here that we do not consider these workshops to be the proper forum for more far-reaching discussions regarding an incentive ratemaking mechanism for attrition years, so Staff should not pursue that idea further in these workshops.
3. Results of Operations
- a. Developing a standard format for the “Summary of Earnings” table produced by the RO model to be incorporated into each utility’s RO model;
 - b. To more efficiently complete the RO modeling for the proposed decision, developing a single approach across utilities to the working relationship with the ALJ and Energy Division staff; and
 - c. Developing and incorporating standardized bill impact calculations into every GRC application.

We continue this list with several additional topics discussed earlier in this decision:

4. GRC Phase 2 schedule and filing requirements: as we noted in Section 5.2 above, PG&E suggested in its comments on the PD that the Commission would benefit from a more robust record on whether to modify the filing requirements for GRC Phase 2 applications.
5. Framework for attrition year revenue requirements
 - a. How can the Commission's reporting requirements be used to enable Commission staff to monitor how utilities reprioritize authorized GRC funding during a GRC cycle?
 - b. Do any gaps exist in reported data, where certain costs funded through a GRC are not subject to spending accountability reporting?¹¹³
 - c. Today, attrition year revenue requirements are determined by escalation factors and/or Commission authorization of specific capital spending plans. Major new developments beyond the utility's control are often granted memorandum account treatment, or addressed using a "z-factor" mechanism. Does the addition of a third attrition year require any additional mechanism, beyond those listed here?¹¹⁴

Finally, regarding scheduling, we agree with TURN's observation that Staff's proposal to divide these topics between several workshops spread out over many months may be too gradual, in light of the progress already made by Staff and the parties to identify potential policy changes to streamline the processing of GRCs. However, we are mindful that implementing the requirements in Section 5.4 of this decision for additional attrition years for Sempra and SCE will require prioritizing Staff and party resources in the near term. We leave it to Staff and interested parties to decide the best way to address the topics we list above within the next 12 months, while relying on pre-planning

¹¹³ See, TURN Comments on the PD at 3-4.

¹¹⁴ See, SCE Comments on the PD at 2-4.

as suggested by SCE to focus activity at the workshop(s) on finalizing parties' proposals and recommendations.

5.6. Should the Commission Open a “Tax Rulemaking”?

The Staff Report includes a recommendation that the Commission open a new rulemaking to revisit its policies on the utilities' recovery of income tax expenses and related rate base issues.¹¹⁵ Staff explains that in recent energy GRCs a number of issues pertaining to income tax expenses were heavily contested and litigated. Furthermore, Staff suggests that the Commission's policies on taxes may not have kept pace with recent changes in the tax law. Staff concludes that “a look at the Commission's policies on the utilities' recovery of income tax expenses is long overdue” and recommends that the Commission open a new rulemaking in order to adopt a consistent tax policy for all the energy utilities.

Parties' comments on this recommendation ranged from tentative support to outright opposition. SDG&E and SoCalGas would support a “properly scoped” rulemaking.¹¹⁶ TURN, while it “would not oppose” such a rulemaking, notes that it would be difficult to effectively participate in the “foreseeable future” because of the demands of other Commission matters, such as GRCs, wildfire-related applications, rate design-related dockets, resource planning and procurement proceedings, among others.¹¹⁷ SCE suggests the Commission consider this to be a “lower-priority issue” as it reviews the Energy Division's

¹¹⁵ Staff Report at 27, Section 7.3.

¹¹⁶ SDG&E and SoCalGas Comments at 3.

¹¹⁷ TURN Comments at 3.

recommendations.¹¹⁸ Finally, PG&E does not agree that a separate rulemaking on taxes is necessary, given the balancing and memorandum accounts that have already been adopted for the utilities to address tax changes as well as the processes currently underway to adjust the IOUs' revenue requirements to reflect recent changes to the Internal Revenue Code resulting from the Tax Cuts and Jobs Acts of 2017 (TCJA).¹¹⁹

Based on these comments, we find that it is not necessary to open a new rulemaking to address tax issues. In GRC decisions issued more recently than the Staff Report, the Commission directed each of the energy utilities to establish Tax Memorandum Accounts with a common structure.¹²⁰ Our intent in doing so was to address the types of concerns raised by the Energy Division in the Staff Report. And as noted by PG&E, following passage of the TCJA we directed each utility subject to our jurisdiction (including all energy utilities) to take certain actions to pass any tax savings that resulted from the new legislation immediately on to ratepayers. In short, we are comfortable that the Commission and its staff are now equipped to monitor changes in the tax law and quickly exercise our oversight over the utilities in order to ensure that ratepayers are treated fairly as new provisions are implemented.

5.7. Closure of this Rulemaking

The Staff Report recommends that the Commission close R.13-11-006 and open a new rulemaking to implement the recommendations adopted in this decision. As we explained at the outset of this decision, the Commission opened

¹¹⁸ SCE Comments at 5.

¹¹⁹ PG&E Comments at 2 and 8-9.

¹²⁰ See, for SDG&E and SoCalGas, D.16-06-054, Ordering Paragraph (OP) 4; for PG&E, D.17-05-013, OP 11; and for SCE, D.19-05-020, OP 5.

this rulemaking primarily to develop and adopt a risk-based decision-making framework to evaluate safety and reliability improvements in the rate cases of the energy utilities. The Commission completed that task when it adopted D.14-12-025, but left this proceeding open in order to provide a forum for the issues that we resolve in this decision. Today's decision addresses all of the tasks within the scope of R.13-11-006. While we do expect that the workshops we endorse in this decision will yield additional "actionable" recommendations to improve our GRC process, we will treat parties' obligations to provide those recommendations as "compliance items." By doing so, we can close this rulemaking with the issuance of this decision, while preserving the option to either reopen this proceeding or initiate a new rulemaking, depending on the recommendations ultimately provided by parties.

6. Comments on Proposed Decision

The proposed decision of Commissioner Rechtschaffen in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on October 24, 2019 by PG&E, SCE, SoCalGas and SDG&E (jointly), Public Advocates, TURN and CUE. Reply comments were filed on October 24, 2019 by PG&E, SCE, Public Advocates, and TURN.

Pursuant to Rule 14.3(c), comments shall focus on factual, legal or technical errors in the proposed decision and in citing such errors shall make specific references to the record or applicable law. Comments which fail to do so will be accorded no weight. Comments proposing specific changes to the proposed or alternate decision shall include supporting findings of fact and conclusions of law. Pursuant to Rule 14.3 (d), replies to comments shall be limited to

identifying misrepresentations of law, fact or condition of the record contained in the comments of other parties.

All commenters support (or, in the case of TURN, accept) the PD's adoption of four-year GRC cycle, and PG&E also supports combining its GT&S and GRC proceedings.¹²¹ All commenters also support changing the due date for the Public Advocates Office's opening testimony. However, each of the commenters recommends a number of adjustments to the revised RCP schedule provided in the PD. The PD has been modified in a number of areas in response to parties' comments and recommendations.

7. Assignment of Proceeding

Clifford Rechtschaffen is the assigned Commissioner in this proceeding.

Findings of Fact

1. The Commission follows a RCP to govern the information, processes, and schedule associated with the GRC applications of the energy utilities.

2. In order to adopt and develop a risk-based decision-making framework to evaluate safety and reliability improvements, D.14-12-025 modified the schedule of the RCP previously followed by the energy utilities pursuant to Appendix A of D.07-07-004.

3. Modifying the RCP to add a third attrition year and create a four-year GRC cycle without making other changes to the RCP schedule would not lead to more efficiencies.

¹²¹ TURN states that it continues to believe that a three-year GRC cycle is preferable. Rather than re-argue its case in its comments, TURN addresses what it perceives as misguided assumptions and analytical errors in the PD.

4. Pursuant to Ordering Paragraph 101 of D.19-09-025, unless otherwise directed by the Commission, PG&E shall file its next GT&S rate case consistent with the schedule required for a 2023 test year.

5. The Commission would gain a total-company perspective on PG&E's cost of service, including risk-related spending, if PG&E's GT&S- and GRC-related revenue requirements were reviewed in a single general rate case.

6. The amount of time presently allowed in the RCP for the Public Advocates Office to complete discovery and prepare its testimony is inadequate.

7. If the GRC proceedings began in May instead of September, the schedule would enable the Commission to issue its final decision prior to the utility applicant's test year.

8. Additional workshops could explore standardizing the organization and format of GRC and RAMP filings; the possible use of stipulated terms and rebuttable presumptions to reduce litigated issues, and improving the accuracy of attrition year forecasting, escalation factors, and ratemaking; high level consistency in the Results of Operations modeling process across utilities; and the timing and implementation of Phase 2 applications on electric and gas rate design and cost allocation.

9. There is no need to conduct workshops to produce complete uniformity in the results of operation model, or to consider the use of the FERC's Uniform System of Accounts in the utilities' GRC applications.

10. There is no need for the Commission to open a rulemaking on GRC-related tax issues because in recent GRC decisions the Commission has directed each of the energy utilities to establish Tax Memorandum Accounts with a common structure. This will enable the Commission to monitor changes in the tax law

and quickly exercise its oversight over the utilities in order to ensure that ratepayers are treated fairly as new provisions are implemented.

Conclusions of Law

1. The end goal of this rulemaking is to revise the RCP to better facilitate utility revenue requirement showings based on a risk-informed decision-making process that will lead to safe and reliable service levels that are in compliance with state and federal guidelines, rational, well-informed and comparable to the best industry practices, and that the adopted rates are just and reasonable.

2. The RCP should be modified if it will enable GRC proceedings to be conducted more efficiently.

3. No evidentiary hearings are needed in this proceeding because this is a quasi-legislative proceeding which establishes policy, and the Commission can consider and base its policy determinations on the pleadings and comment process which has been filed in this proceeding.

4. The RCP should be revised to require that the GRCs of PG&E, SCE, SoCalGas and SDG&E follow a four-year cycle based on a forecast test year revenue requirement, followed by three attrition years.

5. PG&E's GT&S- and GRC-related revenue requirements should be reviewed in a single general rate case.

6. The GRC RCP schedule shown in Appendix A to this decision should modify and replace the RCP schedule adopted by the Commission as shown in Table 4 of D.14-12-025 and should take effect on June 30, 2020.

7. PG&E, SCE, SoCalGas and SDG&E should take all procedural steps necessary to implement the schedule for the transition from the current three-year GRC cycle to the four-year GRC cycle, as provided in Appendix B to this decision.

8. The inclusion of bill impacts for residential customer in utility GRC applications, differentiated by usage in each climate zone, or other means, in the applicant's service territory, would help the Commission determine whether its decision on the application will result in just and reasonable rates.

9. The Commission's Energy Division, in consultation with the Safety and Enforcement Division, as needed, should facilitate a workshop or workshops within twelve months of today's date, and subsequent workshops as needed, to address the topics listed in Section 5.5.5 of this decision, "Adopted Workshop Topics and Schedule."

10. The Commission should not open a new rulemaking to address tax issues.

ORDER

IT IS ORDERED that:

1. Table 1 in Appendix A to this decision modifies and replaces the "GRC Application Filing Schedule" presented in Table 4 of Decision 14-12-025.

2. Beginning June 30, 2020 the "GRC Application Filing Schedule" presented in Table 1 in Appendix A to this decision shall apply to all future General Rate Case application filings of Pacific Gas and Electric Company, Southern California Edison Company, Southern California Gas Company, and San Diego Gas & Electric Company.

3. Pacific Gas and Electric Company, Southern California Edison Company, Southern California Gas Company, and San Diego Gas & Electric Company shall take all procedural steps necessary to implement the schedule for the transition from the current three-year GRC cycle to the four-year GRC cycle, as provided in Appendix B to this decision.

4. Pursuant to Ordering Paragraph 101 of Decision 19-09-025, Pacific Gas and Electric Company is directed to incorporate its requests for test year 2023

revenue requirements related to its gas transmission and storage systems into its test year 2023 general rate case application.

5. The Commission's Energy Division, in consultation with the Safety and Enforcement Division, as needed, shall facilitate a workshop or workshops within twelve months of today's date to address the topics listed in Section 5.5.5 of this decision, "Adopted Workshop Topics and Schedule." No later than 30 days after the conclusion of the workshop or workshops, a designated utility shall submit a report to the Directors of the Energy Division and Safety and Enforcement Division with copies to this proceeding's service list summarizing the workshop or workshops and any agreed-upon proposals, as a compliance item in this docket.

6. As a compliance item in this docket, Pacific Gas and Electric Company, Southern California Edison Company, Southern California Gas Company, and San Diego Gas & Electric Company shall develop bill impact calculations for residential customers in the applicant's service territory, differentiated by usage in each climate zone, or other means as may be directed by the Commission or by the Director of the Energy Division, to be included in every future GRC application. The utilities shall present their standardized calculations for discussion at the workshop or workshops facilitated by the Energy Division, in consultation with the Safety and Enforcement Division, as needed, pursuant to Ordering Paragraph 5 of this decision.

7. Rulemaking 13-11-006 is closed.

This order is effective today.

Dated January 16, 2020, at San Francisco, California.

MARYBEL BATJER

President

LIANE M. RANDOLPH

MARTHA GUZMAN ACEVES

CLIFFORD RECHTSCHAFFEN

GENEVIEVE SHIROMA

Commissioners

APPENDIX A

Table 1
Adopted Revised GRC Application Filing Schedule
Effective June 30, 2020

Date	Days	Event
Test Year minus-3		
May 15	Day 0	Utility files application to initiate its RAMP proceeding
By September 1	~Day 110	SED files and serve report on utility's RAMP submission.
By November 15	~Day 184	Opening comments on RAMP submission and the SED report
By December 1	~Day 200	Reply Comments
Test Year minus-2		
May 15	Day 0	Utility files GRC application, and serves prepared testimony
By May 30	~Day 15	Utility holds public workshop on overall GRC application
30 days after Daily Calendar notice	~Day 30	Due date for protests and responses to GRC application, pursuant to Rule 2.6(a)
By June 30	~Day 45	Prehearing Conference held
By August 15	~Day 90	Scoping Memo of Assigned Commissioner issued
To be decided		Public Participation Hearings
By December 15	~Day 215	Public Advocates Office and other intervenors serve opening testimony
Test Year minus-1		
By January 30	~Day 260	Concurrent rebuttal testimony served
By February 25	~Day 285	Evidentiary hearings begin
By March 15	~Day 305	Evidentiary hearings end
To be decided		Update testimony and hearings, if necessary
By April 20	~Day 340	Briefs filed
By May 12	~Day 360	Reply briefs filed
By August 3	~Day 445	Status conference, proceeding submitted for Commission decision [Rule 13.14(a)]
By November 1	~Day 535	Proposed decision mailed for comment
By December 1	~Day 565	Final decision adopted
Test Year		
January 1	~Day 595	Effective date of final decision

(END OF APPENDIX A)

APPENDIX B

Schedule for the Transition from the
Current Three-Year GRC Cycle to the Four-Year GRC Cycle

Filing Date	PG&E	SCE	SDG&E and SoCalGas
August 30, 2019		GRC: A.19-08-013 • Test Year: 2021 • Attrition Years: 2022-2023	
November 7, 2019			I.19-11-010 and I.19-11-011 opened for SDG&E and SoCalGas RAMPs
For SDG&E and SoCalGas: as soon as practicable For SCE: As directed		SCE shall amend A.19-08-013 to propose an additional attrition year for 2024, as directed	SDG&E and SoCalGas shall file Petitions for Modification of D.19-09-051 to add 2022 and 2023 attrition years
By June 30, 2020	Files 2023-2026 RAMP application		
May 15, 2021			SDG&E and SoCalGas shall file 2024-2027 RAMP applications
By June 30, 2021	<u>Files combined GRC/GT&S application:</u> • 4-year cycle • Test Year: 2023 • Attrition Years: 2024-2026		
May 15, 2022		Files 2025-2028 RAMP application	<u>Files next GRC application:</u> • 4-year cycle • Test Year: 2024 • Attrition Years: 2025-2027
May 15, 2023		<u>Files next GRC application:</u> • 4-year cycle • Test Year: 2025 • Attrition Years: 2026-2028	

(END OF APPENDIX B)