**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 | R.13-11-006<br>(filed November 14, 2013) |

# PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 M) PROPOSED REVISIONS TO THE FEBRUARY 20, 2014 STRAW PROPOSAL

J. MICHAEL REIDENBACH
STEVEN W. FRANK

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-6976
Facsimile: (415) 973-0516
E-Mail: SWF5@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: April 7, 2014

On March 21, 2014, Ms. Marzia Zafar, Director of the California Public Utilities Commission's Policy and Planning Division, requested proposed revisions to the Straw Proposal issued on February 20, 2014.

Accordingly, Pacific Gas and Electric Company (PG&E) has attached two copies of its proposed revisions to the February 20, 2014 Straw Proposal: (i) a "redlined" copy showing the changes recommended by PG&E and (ii) a "clean" copy in which the redlined changes have been accepted. PG&E's proposed revisions include a recommended timeline for Phase 1 of the General Rate Case (GRC) in a new Attachment A to the Straw Proposal, as well as recommendations for streamlining the GRC process in a new Attachment B.

The redlined copy is included as Exhibit 1. The clean copy is Exhibit 2.

Respectfully Submitted,

STEVEN W. FRANK

By: *\/s\/ Steven W. Frank*
STEVEN W. FRANK

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-6976
Facsimile: (415) 973-0516
E-Mail: SWF5@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: April 7, 2014

# Exhibit 1
# PG&E Revised Staff Straw-Proposal
# Redline version

# PG&E Revised Staff Straw-Proposal
# R.13-11-006

~~The Commission staff will convene a three-day workshop to discuss this proposal. This will be an iterative process where we will refine as we get feedback from all stakeholders. The workshops are scheduled to begin on March 19th at the Commission Auditorium. More details on the workshop to follow.~~

~~The large utilities (i.e. SoCalGas, PG&E, SDG&E, and Edison) are asked to submit and serve a case study utilizing the new process – see below. By case study we mean we want the utilities to take this proposal and create an example of how it could work in real life – e.g. a utility can file its own Risk Assessment Planning Proceeding (RAPP) using hypotheticals. We are requesting this approach because the case studies can be used in the workshop to revise/refine the proposal. The utilities are asked to submit and serve their case studies on March 11th.~~

~~Logistically, the next steps on this proposal are as follows:~~

1. ~~SoCalGas, PG&E, SDG&E, & Edison are to submit and serve their case studies on March 11, 2014~~
2. ~~Workshops (March 19, 20, & 21) with all stakeholders to get feedback~~
3. ~~Staff will revise the proposal based on the feedback from the workshops~~
4. ~~Parties will file formal opening and reply comments on the revised proposal.~~
5. ~~Prehearing Conference (PHC) will be scheduled for April 29, 2014 – ruling to follow.~~

## I. Introduction

~~Coming out of the energy crisis, the Commission radically changed its policies around energy procurement to ensure reliability as it formed the so called "hybrid market" that combined elements of regulated utility services with competitive markets. This process evolved over the years to become the Long-Term Procurement Plan proceeding (LTPP). The LTPP combined two core functions: approving short-term (generally less than five year) procurement of electric energy supplies on an expedited schedule, and approving long-term contracts for generating resources to ensure adequate generation capacity was available to meet planning reserve margins.~~

Since the San Bruno natural gas pipeline explosion in 2010, the Commission has faced a ~~similar~~ need for transformation of its policies concerning the safety and resiliency of utility operations. In response to date, the Legislature has enacted multiple statutes, and the Commission has also opened several investigations and rulemakings; however, neither the statutes nor the rulemakings/investigations fundamentally changed the core mechanisms by which regulated utilities consider risk and safety.

In this Rulemaking – R.13-11-006 - the Commission has asked stakeholders how to more effectively integrate safety into utility General Rate Case (GRC) funding proposals, and also asked for ideas to potentially streamline the GRC process. Over eighteen different stakeholders filed comments in response to the Rulemaking. ~~The~~

On February 20, 2014, Commission staff circulated a first draft of this Staff Straw Proposal ~~draws~~that drew on the ideas proposed by the Office of Ratepayer Advocates and the Coalition of California Utility Employees, among other stakeholders. On March 19-21, 2014, Commission staff hosted a three-day workshop to discuss the first draft of the Straw Proposal, after which comment was invited on the first draft. This Revised Straw Proposal takes into account the discussions at the workshop, as well as comments provided on the first draft.

~~This Staff Proposal is introducing a process modeled after the LTPP proceeding. The LTPP proceeding focuses on ensuring reliability and ensuring necessary capacity is brought online consistent with state policy goals. Essentially, the LTPP utilizes a transparent stakeholder process to identify need for resources based on load forecasts, policy directives and future expectations about resource availability and directs each utility to procure a portfolio of contracts to ensuring sufficient generation supply on a territory-wide and local resource area. We are proposing that a similar mechanism be created for complete and transparent stakeholder process to form a risk-mitigation portfolio for each utility – i.e. identifying and ranking the risks to a safer and more resilient system~~ ~~**using a uniform process**~~~~, and providing a mechanism for the utilities to propose specific projects to reduce or allay that risk.~~

The goal of this proposal is to develop fundamental regulatory processes for defining, acquiring, and disseminating risk-based information that supports rate-setting and ~~project~~ prioritizing decisions. This new process~~ – whether in a separate proceeding or a phase of the GRC proceeding –~~ should include the following:

- Description of the utility asset ~~needing replacement or upgrade. The~~risk being addressed, the current estimated risk, the existing controls already in place to mitigate the risk, and the effect of not upgrading or replacing the asset or ~~upgrading~~implementing other mitigations.
- A description ~~on~~of the method used to estimate the risk. For instance was the risk scored on a purely quantitative basis, a Subject Matter Expert (SME) basis, or a hybrid approach?
- What alternative solutions are available to reduce or eliminate the risk?
- The estimated risk reduction if the replacement~~ or~~, upgrade ~~is authorized~~or other mitigations are adopted or if the other alternatives are ~~authorized~~adopted.

Developing these processes and the capability to credibly deliver and interpret risk information suggests that several other supporting capabilities may also need to be in place. Utilities may need to expand their risk management processes and data capture and analysis capabilities, and the Commission, as well as interveners may need to expand their own capabilities and understanding of risk management.

~~Here are two possible alternatives for incorporating this process into GRC decision making:~~

~~A) A separate proceeding, conducted separately from and in advance of the GRC application, which results in a risk-informed portfolio of projects to address identified risks and uncertainties, and~~



SB_GT&S_0108578

~~which establishes a ranking of these projects based on their expected costs and anticipated value to ratepayers. For the purposes of this proposal, we coin the term Risk Assessment Planning Proceeding (RAPP).~~ The ~~Commission-approved results of the RAPP process would then be incorporated into the utility GRC application as part of expenditure requests for utility operations and capital improvements.~~

~~Instead of holding a separate proceeding, the risk~~risk assessment ~~and project planning could~~process should occur as the first Phase of each utility's GRC proceeding~~, with~~. As appropriate, the risk-reduction ~~project~~ portfolio ~~comprising a~~may be comprised of one or more separate ~~book~~books of testimony and related ~~working~~work papers, ~~and~~from which the ~~budget~~forecast for the approved project list would ultimately be incorporated into the utility's total revenue request for that Test Year.

~~While this proposal has selected these two options for consideration, Staff is not opposed to alternatives that fit the concepts further described in this paper. Regardless of the structure for considering risk and mitigation, however, this proposal~~ This proposal also sees a necessity for adding ~~a~~ new verification ~~component to GRCs, which would entail the utility at the time it files its Notice of Intent (NOI) to also file a very simple chart showing the projects that were approved versus the projects that were implemented.~~components. This verification process is discussed in more detail in the later section of this proposal.

~~Setting aside for the moment the matter of whether risk analysis is separate and preliminary to the GRC, or an early Phase of the case, this approach~~ This proposal essentially consists of three components:

- Step 1 is to identify the risks that need to be addressed for a safer and more resilient system, and to create a process that allows the utility to bring to the Commission its justification/rationale for these risks and ways to mitigate them. The outcome of this Step would ~~provide guidance for establishing recommended levels of funding for Safety and Resiliency. We'd like to discuss at the workshop whether this step should be incorporated into the GRC rate case plan.~~be one or more reports from SED or its consultants that assess (i) the risk assessment process, mitigation plans and controls that provide the basis for the forecasted work to be included in the GRC and (ii) the technical merits of the assessment process, mitigation plans and controls.

- Step 2 is the traditional General Rate Case litigation for each utility~~. The prior identification and/or ranking of the risks to~~ in which the utility would be expected to have addressed any technical recommendations in the SED report(s) (or explain why it has not done so). The technical assessment in the SED report(s) would not guarantee that ~~all~~the related costs proposed in the GRC will get approved. In the GRC, stakeholders can debate the cost as well as the path the utility has chosen to eliminate and/or mitigate the risks identified.

- Step 3 is verification. ~~The Commission requires **a uniform and simple verification** system that will be reported by the utility to the Commission's Safety & Enforcement Division (SED). For example, if utility X was approved in 2015 to replace 1000 poles by 2020 with a budget of $200 million; in 2020 the utility should show in a most simple chart that 1000 poles were approved in~~

~~2015; in 2016 250 poles were replaced at a cost of $30 million; in 2017 300 poles were replaced at a cost of $65 million; in 2018 450 poles were replaced at a cost of $100 million; the utility will refund the extra $5million and/or will use it for something else that it will clearly identify. This should be illustrated in a table and will include other items that were approved in the GRC.~~ This revised straw proposal envisions three elements of verification. The first element of verification pertains to the SED's review of the utilities' enterprise and operational risk management programs. The Commission would require SED staff to evaluate whether the utilities' risk programs reflect appropriate risk management principles and methods. This review would take place on a periodic basis and not necessarily as part of the GRC proceeding. The second element pertains to a technical review and would take place upon the filing of the utility's GRC application. That is, the Commission would require SED staff or its consultants to verify that the forecasted work in the utility's formal application has addressed each of the technical recommendations in the SED report(s) issued in that GRC's prior risk phase. The third element of verification pertains to utility spending. For this verification, the Commission would require the utility to submit to the Energy Division a report on utility spending, compared to authorized or imputed amounts, for the operational lines of business by March 31 of the following year. The Energy Division would monitor levels of spending, including possible field assessments of work conducted. Energy Division reports on such spending could be made part of the record in subsequent GRCs.

~~In the next sections we will further explain each of these three steps.~~

At this time, the new risk procedures shall apply only to the three major energy utilities GRCs. As experience in this new process is gathered, the Commission will consider expanding this process to include the smaller utilities that are subject to the Commission's jurisdiction.

# II. Risk Assessment

## A. Overall Goal

The goal of this ~~aspect~~Risk Assessment Planning Phase (RAPP) of the proceeding is for the utility to identify and clearly define its priorities and policies for ~~assuring~~operating a system that is safe and ~~resilient system.~~reliable, and that minimizes detrimental impacts on the environment. More specifically, the utility must identify the top asset related risks ~~to~~for its system~~ – the~~, explaining whether such risks ~~must be separated as operational risks that the utility faces, legacy risks, and emerging risks that~~could impact long-term performance ~~and unanticipated risks to a safer more resilient system[1].~~ or other

~~[1] These are suggested risk categories and may be further developed as part of a risk taxonomy identification process in the RAPP~~



SB_GT&S_0108580

operational issues.[2] The utility ~~must justify these~~should also explain whether such risks are based on ~~measureable and verifiable~~a quantitative or qualitative risk assessment.

This process should identify the safety objectives, implementation options, and the information required to evaluate the ~~performance of the proposed projects.~~assessment process, mitigation plans and controls. Further, the utility ~~must~~should also identify recommended risk mitigation projects~~. They should show~~ and/or programs, explaining how, and by how much~~,~~ (if known), each project/program is expected to reduce either the probability of a hazardous event occurring ~~and~~or the consequences of the event if it occurs. The utility should also estimate when ~~they expect~~it expects these safety improvements to be realized and the duration or lifetime of the project/program impacts (e.g. replaced pipe has expected lifetime of "X" years, employees are retrained every three years, etc.). These projects/programs should be identified as either direct safety mitigation projects/programs (e.g. pipeline replacement), detective risk assessment projects/program (e.g. pipeline safety testing and inspection, risk modeling), or safety enabling projects/program (e.g. safety training~~).~~[3] ~~Through this process all stakeholders will have an opportunity to comment on the utilities testimony and provide feedback, if any should be adopted and/or modified. The Commission's final decision would reflect this robust and transparent record.~~, data collection).[4]

~~One of the most apparent challenges is simply identifying the risks to a safer and more resilient system – e.g. breakdowns in infrastructure such as old utility poles in high consequence areas; transformer failures that lead to fires; cybersecurity threats; pipeline failures; natural gas storage failures. The assessment process must be designed to identify and contextualize these risks so that stakeholders can provide, input, feedback and/or meaningful alternatives. The initial workshop for this proceeding is designed to identify/define a risk taxonomy that comprehensively classifies the risks that a utility faces, develop and agree on a set of requirements for measuring risk, evaluate options and alternatives for mitigating risks, and validate a process for prioritizing risks mitigation opportunities.~~

### ~~*a) Guiding Principles for developing risk-based regulations*~~

~~Based on a review of several risk management processes, we have identified five guiding principles of risk management that can form the foundation for proactive risk-based regulation.~~

- ~~Risks involve uncertainty about achieving objectives. Although categories of risk, or even specified risk events can be identified and the likelihood of their occurrence quantified, there is still an underlying element of uncertainty in terms of when, extent of the impact, or ultimate outcomes of some event. Uncertainties are expressed as both negative and positive impacts. Negative impacts hinder the advancement of our objectives and positive impacts promote and enhance our objectives. Regulation should recognize this dual role and capability of risk~~

[2] The utility, SED and participants in the risk phase should use terminology comporting with standard risk definitions as set forth in publications such as the ISO 31000 standard, the Department of Homeland Security Risk Taxonomy or other publications that the CPUC may identify.

~~[3] These are suggested categories that may be further defined as part of the RAPP~~

[4] These are suggested categories that may be further defined as part of the RAPP .



SB_GT&S_0108581

~~management and adopt processes that provide incentives to utilities to address and find innovative ways to control risk in ways that comport with and advance stakeholder objectives.~~

- ~~Risk is an analytically measurable quantity, and may be reduced to a metric that is a function of the probability of an event and the impact of that event. Each event can either enhance or inhibit the ability to achieve objectives. These metrics can characterize risks that have occurred in the past (Lagging indicators) or can also assess our expectations of future events (Leading indicators).~~

- ~~Risk management is predicated on a comprehensive review of risks. The effectiveness of a risk management paradigm depends on the ability to comprehensively review all project risks individually and as a portfolio. Risk occurs at all levels of an enterprise so risk management is the responsibility of everyone.~~

- ~~Learning is a core competency of effective risk management. The task of resolving uncertainties and reducing negative risk requires that organizations plan for and embrace learning and continuous improvement processes as an integral part of risk management.~~

- ~~Transparency in risk evaluation processes and third party review is essential to developing robust comparable risk metrics, confidence in the measurement process, and consistency in overall risk management processes.~~

### ~~*b) Requirements for Risk Assessment and Planning*~~

~~In order to better understand how system-wide risk assessment and management can be used to support and achieve the objectives of safe, resilient and cost effective service, we have developed a preliminary set of regulatory process requirements. These requirements incorporate the five guiding principles and also recognize that developing a robust risk management paradigm for regulating IOUs also requires meaningful and informed input from stakeholders. The key issues to resolve with stakeholder input are how to balance the fundamental objectives of safe and resilient service at reasonable rates; how to determine risk tolerance at the program level; and how to determine an acceptable level of risk for a portfolio of programs in the GRC.~~

~~The risk assessment process (whether in a separate RAPP proceeding or as a Phase of the GRC) is designed to elicit these three fundamental requirements of risk assessment and management in three steps:~~

1. ~~Develop an objectives hierarchy / risk taxonomy,~~
2. ~~Identify and characterize program level risks and mitigating options, and~~
3. ~~Select an acceptable level of risk given a limited set of alternatives.~~

~~These requirements outline the desired outcomes and goals of a new regulatory process.~~

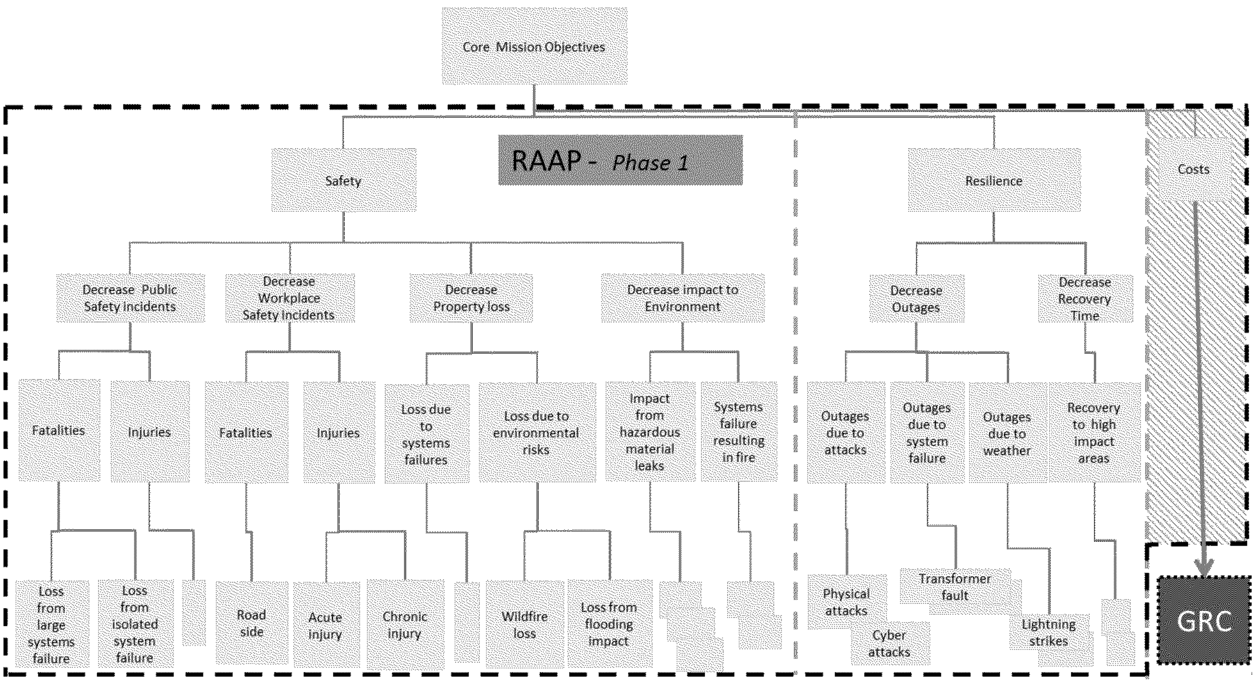
### ~~*1. Develop an Objectives Hierarchy / Risk Taxonomy*~~

~~An objective hierarchy (or risk taxonomy) is a structured way to identify, classify and order the risks that can impact the core objectives of safety, resiliency and costs. While the hierarchy is a stable~~

~~representation of the concerns of stakeholders, it is also a comprehensive and evolving tool. This tool also documents and includes risks that have not recently occurred or may have not yet occurred.[5] This hierarchy has several benefits:~~

- ~~Encourages a comprehensive review of all risks that can impact a utility.~~
- ~~Refines the understanding of how core objectives are managed and can be impacted by specific programs.~~
- ~~Creates a clear method for rolling up risks in an agreed on manner.~~
- ~~Creates a clear way to identify the program risks such as operational, legacy, and emerging risks.~~

~~Initially developing and building out this hierarchy can be a challenge. It will require input from IOUs about the systems and process used to manage their systems. Interveners will also have input into how core objectives should be weighted in this hierarchy. Fundamentally the hierarchy is a tool for mapping core objectives to specific programmatic activities.~~




~~**Exhibit 1: Notional diagram of an objective hierarchy - This is not a comprehensive review of objectives**~~

## ~~*2. Program level risk reporting – Program evaluation*~~

~~With a hierarchy in place, each and every program proposed within the GRC should be identified within that hierarchy. Each of these proposed programs should be evaluated using a simple estimation of risk. This serves two purposes. First it informs the system-wide evaluation of risks. These program level risks~~

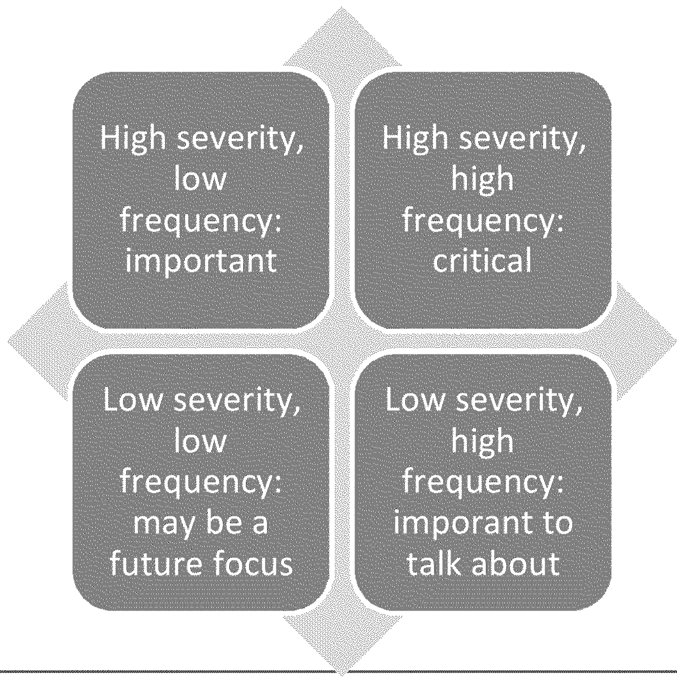
~~[5] The staff straw proposal focuses on the overall risk. However, there is an inherent accepted risk in the present systems. With that in mind, focusing on the net change in risk may be more productive as it relates to acceptance of risk relative to the difference from the present state. This may also help deal with the risk of not taking action on a project. While discussions about the risk inherent in the present systems may be productive overall, it may present a level of complexity that does not essentially focus on the proposed projects.~~

~~can be rolled up using the hierarchy developed above. Second, it specifies an expectation of the program level risks and serves as a simple performance metric.~~

~~Risk evaluation is the IOUs' estimate of the performance expectations, the potential impacts (both negative and positive), and the overall risk mitigation potential for every project within the GRC. While some projects may have a big impact on reliability, and others have an impact on safety, each project nevertheless has some impact on both of these core objectives. This evaluation could be summarized on a one page summary of the projects goals and expectations.~~

### ~~*3. Portfolio segmentation & ranking graphic*~~

~~In order to make an evaluation of the full portfolio of requests made by an IOU, we can segment and then potentially rank a program based on the desired criteria. These criteria can be any of the estimated values used in the previous program evaluation phase. Since each program has already been identified and the impacts to safety, resiliency and cost have been agreed on in program summary phase, we can now segment and then within each of those segments rank each of the programs. The segments can be based on a number of criteria and chosen based on whatever the stakeholders believe is most appropriate. This segmenting also identifies the risk classification, so that each type of program is identified and minimum standards and compliance issues can be assured.~~

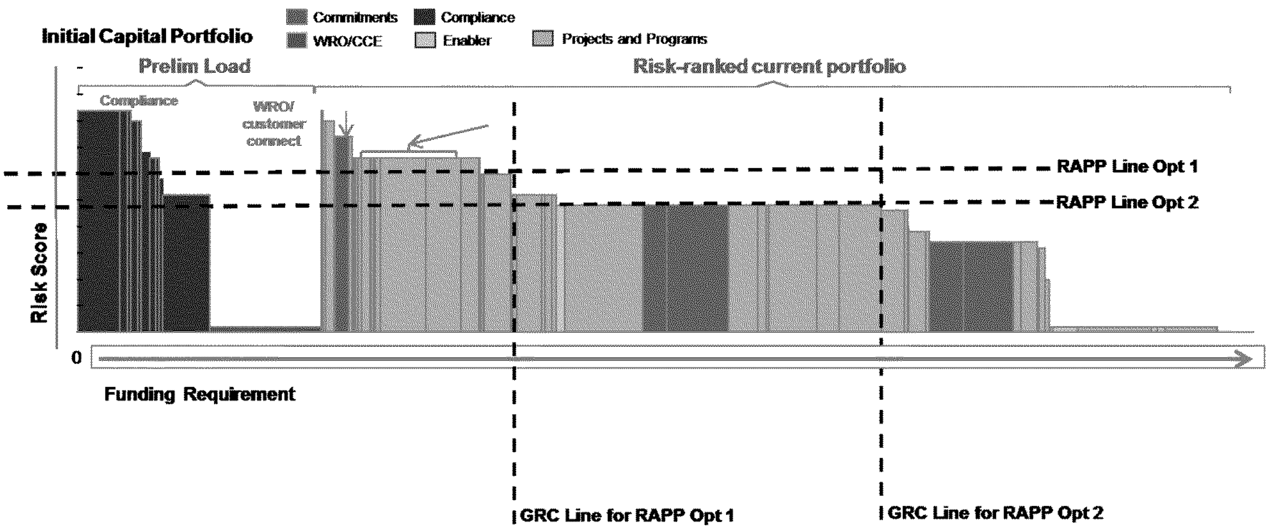



~~Once it is classified whether it is high frequency or low severity, we can then begin to rank each program within that classification/segmentation. Comparing across segmentation the stakeholders would then need to determine the risk cut-off (RAPP line) for all programs – see the figure below. This level of risk acceptance balances all the concerns and implicitly selects projects to be adopted.~~

~~With the risk level established the budget constraint would be established within the GRC process.~~



SB_GT&S_0108584




## B. Scope

The RAPP would address the top ten asset-related risks for which the utility expects to seek recovery in the GRC.

The utility's showing would include:

- A list of the top ten asset-related risks, and a description of the methodology used to determine such risks;
- A description of each of the ten asset-related risks, including: data on the nature of the asset (e.g., units or miles of assets, age of assets, and composition of assets); data used to inform the consequence and frequency related to the risk assessment;
- A description of the controls currently in place, as well as the "baseline" costs associated with the current controls;
- A description of the proposed and alternative additional mitigations considered, the forecasted cost of the mitigations and, if applicable, the expected risk reduction or improvements to safety, reliability and the environment.

## C. Process

The risk phase would commence with the utility submitting its RAPP report to the Safety and Enforcement Division. Concurrently, the utility would file a Notice of Availability of this material with the Commission's docket office, providing service of the NOA to the service list for the utility's prior GRC. At this stage, the Commission would assign a Commissioner and Administrative Law Judge(s) to the



SB_GT&S_0108585

matter. The risk testimony would be submitted in accordance with the overall schedule set forth in Attachment A to this Revised Straw Proposal, which addresses the traditional GRC Phase 1.

Within 30 days of submission of the risk material, the utility and SED would jointly hold a public workshop. During the workshop, the utility would provide an informational overview of the contents of its testimony and SED would explain the process it will follow in conducting its technical review. Participants would be invited to ask questions of the utility and SED, as well as to provide input to SED regarding its upcoming review.

Discovery of information between SED and the utility would be conducted through meetings, site visits, and information requests as SED may choose. Data transmitted from the utility to SED would be formalized through written responses that would be posted on the utility's website (except for confidential responses) for interested parties to review.

Within 150 days of submission of the risk material, the SED would provide to the utility and make available to interested parties one or more draft report(s) that assess (i) the risk assessment procedures that provide the basis for the forecasted work and (ii) the technical merits of the forecasted work. To the extent SED recommends a different portfolio of work than forecasted by the utility, such recommendations should be clearly articulated in the report(s) and the basis for such recommendations provided.

Within 30 days of submission of SED's draft reports, the SED would hold a public workshop to present, answer questions, and receive comments on, its draft report(s).

Within 45 days of the submission of SED's draft report(s), interested parties would provide comments on the draft to SED, the utility and interested parties.

Within 225 days of submission of the risk material, the SED would provide to the utility and make available to interested parties one or more final report(s), taking into consideration comments made on its draft report(s) and input from the public workshop. The SED final report(s) would be made part of the record in the proceeding[6] and SED and/or its consultants would be made available to testify during evidentiary hearings in the GRC. SED would not be expected to become a formal party to the proceeding.

Through this process, all stakeholders will have an opportunity to (i) receive information regarding the utility's operational plans and SED's planned technical review, (ii) review discovery between SED and the utility, (iii) comment and provide feedback on the SED draft report(s), and (iv) cross-examine SED or its consultants during evidentiary hearings. The SED's final report(s) would reflect this robust and transparent record.

[6] The SED report(s) could be included in the utility's formal GRC submittal along with an exhibit showing(i) how the utility addressed the various recommendations in the SED report(s)and (ii) any changes to the proposed programs or projects set forth in the RAPP submittal. Alternatively, the SED report(s) could be included in the record by a ruling from the Assigned Commissioner or ALJ.

# III. Incorporating the Results of Risk Assessment into the General Rate Case (GRC)

General rate cases are a traditional form of regulatory proceeding, in which, a utility files a revenue requirement request based on its estimated operating costs and revenue needs for a particular test year and the Commission determines a just and reasonable revenue requirement. These cases aim to strike a proper balance between risks the utilities take and reasonable opportunity for returns~~, taking into account changing economic conditions.~~. The GRC sets the baseline for utility costs to provide reliable, safe, environmentally sound service at just and reasonable rates. Therefore, regardless of where the ~~system safety and security~~risk mitigation plans will be reviewed and approved, the implementation costs must be reviewed in GRCs.

~~Essentially, the GRCs are entirely cost driven.~~ The GRC approves the revenues and rates for the test year that was litigated. Year 1 is the test year, and for years 2 & 3 an attrition or rather post-test year ratemaking is also litigated and decided in the GRC. The historical practice has been to litigate the post test-year ratemaking within the GRC.

GRCs are typically filed every three years and are staggered to ensure that the Commission and interveners have dedicated staff. A utility's base year under a three-year cycle is actually the utility's test year from the prior GRC. However, if there is a delay, then that could impact the utility's costs in a way different from what was forecast.

This proposal recommends that a ~~four~~three-year rate case cycle be ~~adopted, thereby giving the utility at least one year of actual spend that will become the base year for the next GRC. It should be understood that~~maintained, consistent with Public Utilities Code Section 314.5, which requires the Commission to audit the utilities every three years. Moreover, the further into the future ~~we forecast~~one forecasts the more likely it is that ~~we will be wrong in one direction or another.~~the forecasted programs/projects will differ from those implemented. Therefore, extending ~~our~~the forecast to a ~~four-year~~longer GRC cycle ~~will require the Commission to be flexible in dealing with the differences between forecast and actual results. One possibility could be that the utility would be required to file annual advice letters updating top line cost information.~~

~~The real question is which GRC cycle will be able to incorporate a new risk-analysis~~ would be inadvisable as this process~~. To answer this question we will highlight the GRC cycles of the three large utilities and make a recommendation that is reasonable considering timeliness and completeness of the RAPP record.~~ moves into a more technical realm.

~~Current GRC cycles:~~

- ~~PG&E's GRC = filed in Nov 2012 for test year 2014. The next cycle begins with an application that will be filed in Nov 2015 for test year 2017 (this will commence the 4 year GRC cycle for PG&E of 2017 – 2020.)~~

- ~~PG&E's Gas Transmission and Storage (GT&S) – filed December 2013 for test year 2015. We will propose that the current GT&S cycle continue as a 4 year cycle.[7] This is consistent with the last PG&E GT&S proceeding in which the Commission adopted a 4 year cycle. Under the 4-year (2015 – 2018) cycle, the next filing will be in December 2017 for test-year 2019.~~

- ~~Edison GRC – filed in Nov 2013 for test year 2015. The next cycle begins with application that will be filed in Nov 2016 for test year 2018. (This application will commence the 4 year GRC cycle for Edison of 2018 - 2021)~~

- ~~Sempra GRC – the next filing is an application filed in Nov 2014 for test year 2016. This should be a 4 year cycle (2016 – 2019). This is consistent with the last Commission D.13-05-010 which adopted a 4 year (2012 – 2015) GRC time frame.~~

~~If the first option – a separate RAPP proceeding – is determined to be the best choice, there is an additional consideration of providing sufficient time to conduct a proceeding (however expedited) and giving the utility enough time to incorporate results in its subsequent GRC.~~

~~To make sure the information used in risk assessment is not out of date by the time the GRC is filed and to make sure the utility has had sufficient time to incorporate the risk assessment developed in a RAPP proceeding into its GRC, we think the RAPP proceeding should be scheduled to conclude 12 months before the GRC is filed. Alternatively, the risk assessment phase of the GRC should conclude 12 months before the next phase of the GRC addressing costs is filed.~~

~~With this in mind, we envision that the RAPP will be incorporated in the GRC first time beginning with Sempra's GRC test year 2020 which Sempra will file in November 2018. Working back from that date, the RAPP proceeding will need to be concluded 12 months before November 2018 which is Nov 2017. We envision that this proceeding will take 12 months to process from filing to the issuance of the RAPP decision. So the RAPP proceeding will need to be filed in Nov 2016. We need the parties' input on the how to coordinate the timing of the RAPP with the GRC for best use of the risk assessment.~~

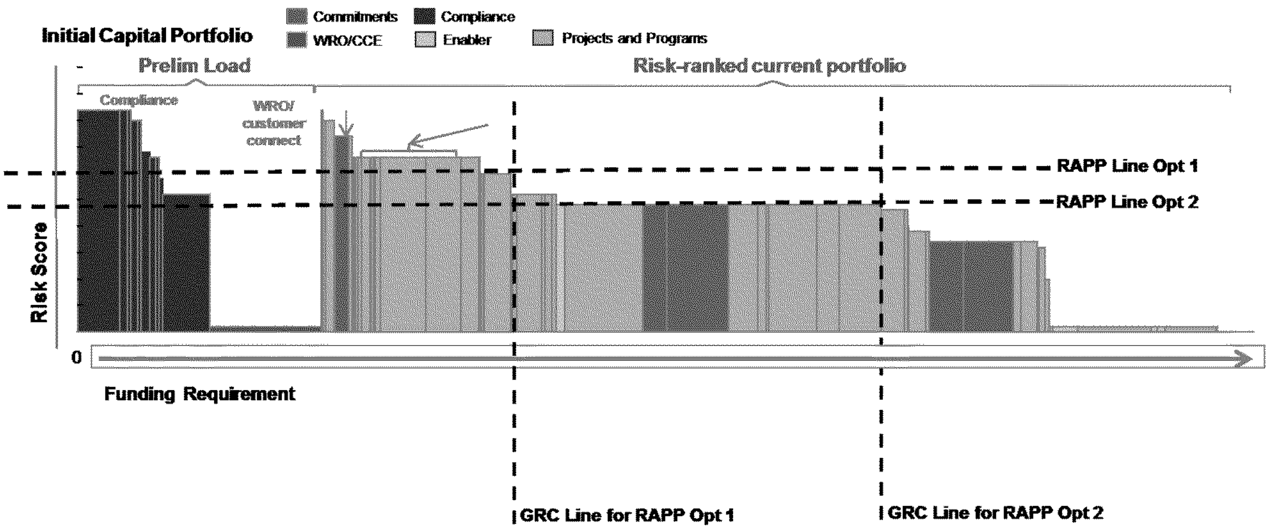
~~As we move along this process, the Commission may want to consider expanding this process to include the smaller utilities that are subject to the Commission's jurisdiction.~~

Given current and pending GRCs before the Commission, the first time this risk assessment process can be incorporated in the GRC would be Edison's 2018 GRC or PG&E's 2018 GT&S case. However, the Commission expects PG&E's 2017 GRC, to be filed in 2015, to reflect these principles as much as possible and to work with SED to achieve the objectives set forth in this Revised Straw Proposal.

In this more traditional phase of the GRC, the Commission would consider all the proposed utility programs to determine which of the programs identified in the RAPP would be funded, as well as what other utility programs set forth in the rest of the GRC showing should be funded. As illustrated in the figure below, the Commission would need to determine the risk cut-off (RAPP line) for all risk mitigation

[7] ~~PG&E has proposed a three year cycle in its application.~~

programs. This level of risk acceptance balances various concerns, and addresses other important work, including compliance, customer commitments, and the like.




# IV. Verification

As stated above, this Revised Straw Proposal calls for three types of verification.

## A. SED Review of Utility Risk Programs

The use of risk-informed decision making is an evolving practice in the energy industry nationwide and within California. While the three large California energy utilities all have enterprise and operational risk management programs in place, they are at various stages in their development. To reflect appropriate risk management principles and methods, SED will regularly review the utility programs. Initially, it would be beneficial to have these reviews take place every three years, although the frequency of such reviews could decrease as the utility programs mature. These reviews would not need to be a formal stage in the GRC proceeding. Rather, the results of the last review for each utility would inform its risk management programs going forward, which – in turn – would inform future RAPP showings.

## B. SED Verification of Utility Response to the SED's Technical Review

The utility is expected to address the SED technical recommendations arising from the RAPP in the utility's GRC application and the utility should provide testimony showing how such recommendations have been addressed. Similarly, as part of the second (more traditional) phase of the GRC, the SED would be expected to verify that the utility has done so. This SED verification report would be submitted within 60 days of the filing of the application.

As a point of clarification, the utility would not be required to *adopt* all of the recommendations made in the SED technical reports, but the utility would be expected to *respond* to all of the recommendations. For instance, if the utility came to the conclusion that it would be too costly to implement a certain recommendation, the utility would not be expected to include such measures in its forecasted revenue



SB_GT&S_0108589

requirement, but the utility would be expected to quantify the costs associated with the recommendation and explain the basis for not incorporating the recommendation in the utility forecast.

Upon submission of the SED verification, the Assigned Commissioner or ALJ would make the verification part of the record in the proceeding. To the extent that SED concludes that one or more recommendations had not been addressed by the utility, the Assigned Commissioner or ALJ may direct the utility to provide additional testimony addressing the missed recommendation(s).

## C. Energy Division Verification of Utility Spending

This verification pertains to utility spending. For this verification, the Commission ~~should~~would require ~~a uniform and simple verification system.~~ the utility to submit to the Energy Division a report on utility spending, compared to adopted or imputed amounts, for the operational lines of business by March 31 of the following year. The Energy Division would monitor levels of spending, including possible field assessments of work conducted.

We note the existence of PU Code 958.5; however, this is different and much simpler. PU Code 958.5 reporting requirement focuses mainly on the review requirement. The verification report that we're looking for is ~~for specific projects – for instance 2000 poles were authorized for upgrade at the authorized cost of $200 million. The utility when they file their NOI will also have to separately file a simple table that has five columns:~~similar to the reporting requirements adopted in PG&E's 2011 GRC.

- ~~Column 1 = what was authorized (replacement of 2,000 poles)~~
- ~~Column 2 = the cost authorized ($200million)~~
- ~~Column 3 = what was actually replaced (as an example let's say 1,900 were replaced)~~
- ~~Column 4 = how much did it actually cost ($200 million actual spend)~~
- ~~Column 5 = a narrative as to why there is a discrepancy~~

The ~~Commission's Safety & Enforcement Division (SED) will be required to draft an independent verification and safety report for each~~ utility ~~prior to their GRC filing. The report will be based on the information that the utility provides and SED's own independent field assessment.~~

~~This proposal would require that the utility file a report at the same time it files its NOI. The report will simply be in the form of a table~~report will mainly consist of simple tables or ~~chart~~charts. It should include a list of ~~items~~safety related risk mitigation programs/projects that were approved in the prior GRC along with the cost/budget that was approved ~~for~~; and a corresponding column that shows what was actual spend and actual build/upgrade. If approved does not match spend by a significant amount, then the utility must include a narrative to explain the discrepancy otherwise no other narrative is required or preferred. ~~The report functions more like an audit of what the utility was approved for and what they actually spent on.~~

~~SED is not asked to testify as part of the next GRC. It will verify what the utility has claimed, issue a report detailing the verification, and provide its assessment of the existing safety-related programs.~~

~~This proposal for verification and assessment could be put into place as part of PG&E's next GT&S filing in December 2017. Given that the GT&S proceeding has no formal NOI process, it is proposed that PG&E will file its GT&S Verification Report in August 2017.~~

As indicated above, the reporting requirements established in PU Code 958.5 are already sufficient and no additional reporting is required for PG&E's gas transmission and storage and Sempra's gas transmission functions.

# V. Next Steps

~~This proposal in whole is and will be an iterative process. We ask the utilities to file case studies using the RAAP process described above. The Commission will hold a three-day workshop to get stakeholder feedback and revise the proposal accordingly, or to incorporate new ideas. Once staff revises the proposal it will be re-issued and that's when we will ask for formal opening and reply comments which will be included as part of the record of this proceeding. We are not asking for comments prior to the workshop.~~

As described in the ALJ's February 26 ruling, a prehearing conference will be held on April 29 to discuss the scope of issues in the rulemaking proceeding and the process for addressing this Revised Straw Proposal. Opening comments on the Revised Straw Proposal are to be filed with the Docket Office and served on or before May 12. Reply comments are to be filed and served no later than May 30.

To promote a shared understanding of the terminology related to risk-informed decision making, SED will develop a proposed glossary of risk-related terms, modeled after the Department of Homeland Security risk lexicon,[8] that will be provided to parties for comment and will be the subject of a future workshop.

[8] DHS Risk Lexicon, 2010 Edition, dated September 2010.

# Attachment A

## Proposed Schedule for GRC Phase 1

| Deadline | Activity | Time After Prior Activity (illustrative and not to conflict with calendar deadlines at left) |
|---|---|---|
| October 1 of Base Year | Utility provides RAPP submittal on operational lines of business | -- |
| November 1 | Utility and SED host public workshop on risk submittal | 30 days after submittal |
| March 1 of Base Year, Plus 1 | SED issues draft report(s) | 150 days after submittal |
| April 1 | SED hosts public workshop on draft report(s) | 30 days after issuance of draft report(s) |
| April 15 | Stakeholders provide comments on SED report(s) | 45 days after issuance of draft report(s) |
| May 15 | SED issues final report(s) | 30 days after receiving comments on draft report(s) |
| September 1 | Utility files GRC application, including possible changes from RAPP submittal | 105 days after issuance of final report(s) |
| October 1 | Utility hosts public workshop on overall GRC application | 30 days after filing of application |
| November 1 | SED issues verification that utility has addressed technical recommendations in SED Report(s) | 60 days after filing of application |
| January 15 of Base Year, Plus 2 | ORA submits report | 4.5 months after filing of application |
| February 1 | Other parties submit opening testimony | 2 weeks after ORA report |
| March 1 | Concurrent rebuttal testimony | 1 month after opening testimony |
| March/April | Public Participation Hearings | |
| March 15 – April 15 | Evidentiary Hearings, including SED participation | 2 weeks after rebuttal testimony |
| May 15 | Opening briefs | 1 month after end of hearings |
| June 7 | Reply briefs | 3 weeks after opening brief |
| July | Update testimony and hearings, if necessary | -- |
| November | Proposed decision | 5 months after reply briefs |
| December | Final decision | 1 month after proposed decision |



SB_GT&S_0108592

# Attachment B

# Streamlining

Keeping to a defined schedule and issuing a final decision prior to the test year is important for both operational and financial reasons. Operationally, the Commission and stakeholders need to keep to a timely schedule in order to (i) ensure that the data used to support Commission decision-making is not stale and (ii) enable the operational improvements proposed in these cases to be promptly implemented. Delayed cases also raise costs. Unpredictable schedules and uncertain funding hinder efficient project implementation. Further, increased administrative costs for the Commission, key stakeholders, and the utilities cause upward pressure on customer rates.

Therefore, the following elements should be implemented in order to streamline the major energy utilities' GRCs.

- Two ALJs should be assigned to the largest rate cases. The presence of two ALJs can facilitate case processing by dividing workload and minimizing delays caused by competing obligations, vacations or illness. Two ALJs can also allow for dual case tracks. For instance, one ALJ could be assigned during the RAPP phase and would be the lead ALJ for issues in the operational lines of business. A second ALJ could then be the lead for the support lines of business.

- Workshops and other informal discovery means should be encouraged. The utilities are encouraged to hold public workshops or other meetings to discuss issues of interest to the Commission and stakeholders. Such informal discovery can reduce (or at lease accelerate) more time-consuming discovery. Presiding Officers, as well as SED and Energy Division staff, are encouraged to attend workshops to facilitate gaining familiarity with the case and the key issues of interest to parties.

- The NOI should be eliminated. Although the presence of the NOI has likely contributed to a more complete record for the processing of GRCs, the amount of time required for the NOI is excessive and unwarranted. Further, the burden of proof is on the utility in GRCs. To the extent that the utility fails to meets its burden because of a flawed application, that risk should rest on the shoulders of the utility.

- The Master Data Request and regular reports should be rationalized. Currently, the utilities spend unnecessary effort on responding to the Master Data Request and preparing reports that are not effectively used by their expected audience. Similarly, recipients of these materials spend too much effort sorting through the materials to find information of particular interest. Therefore, the information requested in the Master Data Request and regular utility reports should be rationalized with an eye toward (i) reducing the amount of needless information provided by the utilities, (ii) ensuring the information is useful to its audience, and (iii) standardizing the presentation of information when possible to do so.

- Transparency between SED and the utility should be the focus of discovery during the RAPP. In order to promote an efficient RAPP process, the utilities should focus on SED discovery requests during the RAPP process, making discovery responses available to all interested parties. Additionally, the utility should provide its RAPP submittal to any interested party and the utility should address others' data requests as a secondary priority. Further, the utility should provide with its formal GRC application an exhibit showing any material changes made in the application to the programs described in the RAPP process. Such an exhibit will allow SED and stakeholders to make the most effective use of their review of the RAPP submittal.

- The Rate Case Plan should establish binding deadlines. Utilities should provide their RAPP submittals and formal GRC applications on calendar deadlines. To the extent that utilities wish to file on alternative dates, the utility shall seek leave to do so with the Executive Director. If the utility fails to meet the established deadline (or one extended by the Executive Director), the utility should face the prospect of penalties. Similarly, Commission staff and stakeholders shall be bound by the deadlines set forth in the Rate Case Plan and must seek leave from the Executive Director if unable to do so. Having established calendar date deadlines from year-to-year will allow for efficient planning. For example, planning for the assignment of ALJs and Commissioners can be done in advance, as can the scheduling of the prehearing conference. SED or other consultants known to be needed to review a utility submittal can be hired in advance. Similarly, staffing for cases, scheduling of vacations and even the reservation of hearing rooms and court reporters can be done in advance and no longer need contribute to delays.

- Prehearing procedural matters should be less time-consuming. With the deadlines established in advance by the Rate Case Plan, parties need not spend time in the early stages of a proceeding negotiating schedules. Rather, the time can be spent on more substantive matters and discovery. Similarly, planning for and attending prehearing conferences should go more quickly and the Scoping Memoranda can be issued more quickly.

- The protest period should be eliminated. Many parties' protests in the larger rate cases are perfunctory. The protests can be more efficiently replaced by a statement of interest of the party that is either provided in a prehearing conference statement or in that party's motion for party status.

- The burden of proof should be clarified as a matter of statewide policy and guidance provided to reduce the volume of data submitted by utilities. The data presented, and requested by intervenors, in the larger rate cases is increasing in a manner that threatens to overwhelm the Commission and many stakeholders. The increased volume, and concomitant case delays, are also contributing to higher costs. Therefore, the Commission should clarify that the burden remains on the utilities to support its forecasts by a preponderance of evidence and that once the utilities have made a prima facie showing, the burden shifts to intervenors to reverse the weight of the utilities' evidence. Furthermore, utilities and intervenors should support their arguments with facts, not mere opinion or disagreement. Arguments without evidence should be summarily rejected.

- Utilities should focus their testimony and workpapers on programs/projects of the greatest cost and importance. Information on smaller programs/projects can have the effect of distracting the Commission and interested parties from issues of greater importance. Therefore, the threshold for detailed program/project data should be increased from $1 million to $5 million in forecasted capital spending.

Exhibit 2

PG&E Revised Staff Straw-Proposal

clean version

# PG&E Revised Staff Straw-Proposal
# R.13-11-006

## I. Introduction

Since the San Bruno natural gas pipeline explosion in 2010, the Commission has faced a need for transformation of its policies concerning the safety and resiliency of utility operations. In response to date, the Legislature has enacted multiple statutes, and the Commission has also opened several investigations and rulemakings; however, neither the statutes nor the rulemakings/investigations fundamentally changed the core mechanisms by which regulated utilities consider risk and safety.

In this Rulemaking – R.13-11-006 - the Commission has asked stakeholders how to more effectively integrate safety into utility General Rate Case (GRC) funding proposals, and also asked for ideas to potentially streamline the GRC process. Over eighteen different stakeholders filed comments in response to the Rulemaking.

On February 20, 2014, Commission staff circulated a first draft of this Staff Straw Proposal that drew on the ideas proposed by the Office of Ratepayer Advocates and the Coalition of California Utility Employees, among other stakeholders. On March 19-21, 2014, Commission staff hosted a three-day workshop to discuss the first draft of the Straw Proposal, after which comment was invited on the first draft. This Revised Straw Proposal takes into account the discussions at the workshop, as well as comments provided on the first draft.

The goal of this proposal is to develop fundamental regulatory processes for defining, acquiring, and disseminating risk-based information that supports rate-setting and prioritizing decisions. This new process should include the following:

- Description of the utility asset risk being addressed, the current estimated risk, the existing controls already in place to mitigate the risk, and the effect of not upgrading or replacing the asset or implementing other mitigations.
- A description of the method used to estimate the risk. For instance was the risk scored on a purely quantitative basis, a Subject Matter Expert (SME) basis, or a hybrid approach?
- What alternative solutions are available to reduce or eliminate the risk?
- The estimated risk reduction if the replacement, upgrade or other mitigations are adopted or if the other alternatives are adopted.

Developing these processes and the capability to credibly deliver and interpret risk information suggests that several other supporting capabilities may also need to be in place. Utilities may need to expand their risk management processes and data capture and analysis capabilities, and the Commission, as well as interveners may need to expand their own capabilities and understanding of risk management.

The risk assessment process should occur as the first Phase of each utility's GRC proceeding. As appropriate, the risk-reduction portfolio may be comprised of one or more separate books of testimony and related work papers, from which the forecast for the approved project list would ultimately be incorporated into the utility's total revenue request for that Test Year.

This proposal also sees a necessity for adding new verification components. This verification process is discussed in more detail in the later section of this proposal.

This proposal essentially consists of three components:

- Step 1 is to identify the risks that need to be addressed for a safer and more resilient system, and to create a process that allows the utility to bring to the Commission its justification/rationale for these risks and ways to mitigate them. The outcome of this Step would be one or more reports from SED or its consultants that assess (i) the risk assessment process, mitigation plans and controls that provide the basis for the forecasted work to be included in the GRC and (ii) the technical merits of the assessment process, mitigation plans and controls.

- Step 2 is the traditional General Rate Case litigation for each utility in which the utility would be expected to have addressed any technical recommendations in the SED report(s) (or explain why it has not done so). The technical assessment in the SED report(s) would not guarantee that the related costs proposed in the GRC will get approved. In the GRC, stakeholders can debate the cost as well as the path the utility has chosen to eliminate and/or mitigate the risks identified.

- Step 3 is verification. This revised straw proposal envisions three elements of verification. The first element of verification pertains to the SED's review of the utilities' enterprise and operational risk management programs. The Commission would require SED staff to evaluate whether the utilities' risk programs reflect appropriate risk management principles and methods. This review would take place on a periodic basis and not necessarily as part of the GRC proceeding. The second element pertains to a technical review and would take place upon the filing of the utility's GRC application. That is, the Commission would require SED staff or its consultants to verify that the forecasted work in the utility's formal application has addressed each of the technical recommendations in the SED report(s) issued in that GRC's prior risk phase. The third element of verification pertains to utility spending. For this verification, the Commission would require the utility to submit to the Energy Division a report on utility spending, compared to authorized or imputed amounts, for the operational lines of business by March 31 of the following year. The Energy Division would monitor levels of spending, including possible field assessments of work conducted. Energy Division reports on such spending could be made part of the record in subsequent GRCs.

At this time, the new risk procedures shall apply only to the three major energy utilities GRCs. As experience in this new process is gathered, the Commission will consider expanding this process to include the smaller utilities that are subject to the Commission's jurisdiction.

# II. Risk Assessment

## A. Overall Goal

The goal of this Risk Assessment Planning Phase (RAPP) of the proceeding is for the utility to identify and clearly define its priorities and policies for operating a system that is safe and reliable, and that minimizes detrimental impacts on the environment. More specifically, the utility must identify the top asset related risks for its system, explaining whether such risks could impact long-term performance or other operational issues.[1] The utility should also explain whether such risks are based on a quantitative or qualitative risk assessment.

This process should identify the safety objectives, implementation options, and the information required to evaluate the assessment process, mitigation plans and controls. Further, the utility should also identify recommended risk mitigation projects and/or programs, explaining how, and by how much (if known), each project/program is expected to reduce either the probability of a hazardous event occurring or the consequences of the event if it occurs. The utility should also estimate when it expects these safety improvements to be realized and the duration or lifetime of the project/program impacts (e.g. replaced pipe has expected lifetime of "X" years, employees are retrained every three years, etc.). These projects/programs should be identified as either direct safety mitigation projects/programs (e.g. pipeline replacement), detective risk assessment projects/program (e.g. pipeline safety testing and inspection, risk modeling), or safety enabling projects/program (e.g. safety training, data collection).[2]

## B. Scope

The RAPP would address the top ten asset-related risks for which the utility expects to seek recovery in the GRC.

The utility's showing would include:

- A list of the top ten asset-related risks, and a description of the methodology used to determine such risks;
- A description of each of the ten asset-related risks, including: data on the nature of the asset (e.g., units or miles of assets, age of assets, and composition of assets); data used to inform the consequence and frequency related to the risk assessment;

[1] The utility, SED and participants in the risk phase should use terminology comporting with standard risk definitions as set forth in publications such as the ISO 31000 standard, the Department of Homeland Security Risk Taxonomy or other publications that the CPUC may identify.
[2] These are suggested categories that may be further defined as part of the RAPP .

- A description of the controls currently in place, as well as the "baseline" costs associated with the current controls;
- A description of the proposed and alternative additional mitigations considered, the forecasted cost of the mitigations and, if applicable, the expected risk reduction or improvements to safety, reliability and the environment.

## C. Process

The risk phase would commence with the utility submitting its RAPP report to the Safety and Enforcement Division. Concurrently, the utility would file a Notice of Availability of this material with the Commission's docket office, providing service of the NOA to the service list for the utility's prior GRC. At this stage, the Commission would assign a Commissioner and Administrative Law Judge(s) to the matter. The risk testimony would be submitted in accordance with the overall schedule set forth in Attachment A to this Revised Straw Proposal, which addresses the traditional GRC Phase 1.

Within 30 days of submission of the risk material, the utility and SED would jointly hold a public workshop. During the workshop, the utility would provide an informational overview of the contents of its testimony and SED would explain the process it will follow in conducting its technical review. Participants would be invited to ask questions of the utility and SED, as well as to provide input to SED regarding its upcoming review.

Discovery of information between SED and the utility would be conducted through meetings, site visits, and information requests as SED may choose. Data transmitted from the utility to SED would be formalized through written responses that would be posted on the utility's website (except for confidential responses) for interested parties to review.

Within 150 days of submission of the risk material, the SED would provide to the utility and make available to interested parties one or more draft report(s) that assess (i) the risk assessment procedures that provide the basis for the forecasted work and (ii) the technical merits of the forecasted work. To the extent SED recommends a different portfolio of work than forecasted by the utility, such recommendations should be clearly articulated in the report(s) and the basis for such recommendations provided.

Within 30 days of submission of SED's draft reports, the SED would hold a public workshop to present, answer questions, and receive comments on, its draft report(s).

Within 45 days of the submission of SED's draft report(s), interested parties would provide comments on the draft to SED, the utility and interested parties.

Within 225 days of submission of the risk material, the SED would provide to the utility and make available to interested parties one or more final report(s), taking into consideration comments made on its draft report(s) and input from the public workshop. The SED final report(s) would be made part of the record in the proceeding[3] and SED and/or its consultants would be made available to testify during evidentiary hearings in the GRC. SED would not be expected to become a formal party to the proceeding.

Through this process, all stakeholders will have an opportunity to (i) receive information regarding the utility's operational plans and SED's planned technical review, (ii) review discovery between SED and the utility, (iii) comment and provide feedback on the SED draft report(s), and (iv) cross-examine SED or its consultants during evidentiary hearings. The SED's final report(s) would reflect this robust and transparent record.

# III. Incorporating the Results of Risk Assessment into the General Rate Case (GRC)

General rate cases are a traditional form of regulatory proceeding, in which, a utility files a revenue requirement request based on its estimated operating costs and revenue needs for a particular test year and the Commission determines a just and reasonable revenue requirement. These cases aim to strike a proper balance between risks the utilities take and reasonable opportunity for returns. The GRC sets the baseline for utility costs to provide reliable, safe, environmentally sound service at just and reasonable rates. Therefore, regardless of where the risk mitigation plans will be reviewed and approved, the implementation costs must be reviewed in GRCs.

The GRC approves the revenues and rates for the test year that was litigated. Year 1 is the test year, and for years 2 & 3 an attrition or rather post-test year ratemaking is also litigated and decided in the GRC. The historical practice has been to litigate the post test-year ratemaking within the GRC.

GRCs are typically filed every three years and are staggered to ensure that the Commission and interveners have dedicated staff. A utility's base year under a three-year cycle is actually the utility's test year from the prior GRC. However, if there is a delay, then that could impact the utility's costs in a way different from what was forecast.

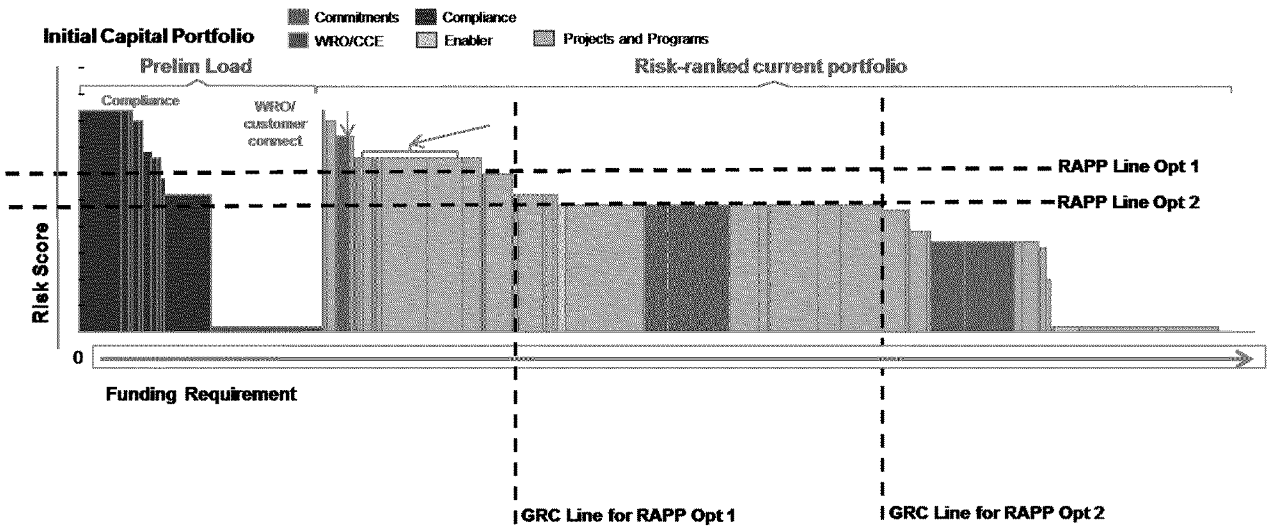
This proposal recommends that a three-year rate case cycle be maintained, consistent with Public Utilities Code Section 314.5, which requires the Commission to audit the utilities every three years. Moreover, the further into the future one forecasts the more likely it is that the forecasted programs/projects will differ from those implemented. Therefore, extending the forecast to a longer GRC cycle would be inadvisable as this process moves into a more technical realm.

Given current and pending GRCs before the Commission, the first time this risk assessment process can be incorporated in the GRC would be Edison's 2018 GRC or PG&E's 2018 GT&S case. However, the Commission expects PG&E's 2017 GRC, to be filed in 2015, to reflect these principles as much as possible and to work with SED to achieve the objectives set forth in this Revised Straw Proposal.

---

[3] The SED report(s) could be included in the utility's formal GRC submittal along with an exhibit showing(i) how the utility addressed the various recommendations in the SED report(s) and (ii) any changes to the proposed programs or projects set forth in the RAPP submittal. Alternatively, the SED report(s) could be included in the record by a ruling from the Assigned Commissioner or ALJ.

In this more traditional phase of the GRC, the Commission would consider all the proposed utility programs to determine which of the programs identified in the RAPP would be funded, as well as what other utility programs set forth in the rest of the GRC showing should be funded. As illustrated in the figure below, the Commission would need to determine the risk cut-off (RAPP line) for all risk mitigation programs. This level of risk acceptance balances various concerns, and addresses other important work, including compliance, customer commitments, and the like.




# IV. Verification

As stated above, this Revised Straw Proposal calls for three types of verification.

## A. SED Review of Utility Risk Programs

The use of risk-informed decision making is an evolving practice in the energy industry nationwide and within California. While the three large California energy utilities all have enterprise and operational risk management programs in place, they are at various stages in their development. To reflect appropriate risk management principles and methods, SED will regularly review the utility programs. Initially, it would be beneficial to have these reviews take place every three years, although the frequency of such reviews could decrease as the utility programs mature. These reviews would not need to be a formal stage in the GRC proceeding. Rather, the results of the last review for each utility would inform its risk management programs going forward, which – in turn – would inform future RAPP showings.

## B. SED Verification of Utility Response to the SED's Technical Review

The utility is expected to address the SED technical recommendations arising from the RAPP in the utility's GRC application and the utility should provide testimony showing how such recommendations have been addressed. Similarly, as part of the second (more traditional) phase of the GRC, the SED would be expected to verify that the utility has done so. This SED verification report would be submitted within 60 days of the filing of the application.

As a point of clarification, the utility would not be required to *adopt* all of the recommendations made in the SED technical reports, but the utility would be expected to *respond* to all of the recommendations. For instance, if the utility came to the conclusion that it would be too costly to implement a certain recommendation, the utility would not be expected to include such measures in its forecasted revenue requirement, but the utility would be expected to quantify the costs associated with the recommendation and explain the basis for not incorporating the recommendation in the utility forecast.

Upon submission of the SED verification, the Assigned Commissioner or ALJ would make the verification part of the record in the proceeding. To the extent that SED concludes that one or more recommendations had not been addressed by the utility, the Assigned Commissioner or ALJ may direct the utility to provide additional testimony addressing the missed recommendation(s).

### C. Energy Division Verification of Utility Spending

This verification pertains to utility spending. For this verification, the Commission would require the utility to submit to the Energy Division a report on utility spending, compared to adopted or imputed amounts, for the operational lines of business by March 31 of the following year. The Energy Division would monitor levels of spending, including possible field assessments of work conducted.

We note the existence of PU Code 958.5; however, this is different and much simpler. PU Code 958.5 reporting requirement focuses mainly on the review requirement. The verification report that we're looking for is similar to the reporting requirements adopted in PG&E's 2011 GRC.

The utility report will mainly consist of simple tables or charts. It should include a list of safety related risk mitigation programs/projects that were approved in the prior GRC along with the cost/budget that was approved; and a corresponding column that shows what was actual spend and actual build/upgrade. If approved does not match spend by a significant amount, then the utility must include a narrative to explain the discrepancy otherwise no other narrative is required or preferred.

As indicated above, the reporting requirements established in PU Code 958.5 are already sufficient and no additional reporting is required for PG&E's gas transmission and storage and Sempra's gas transmission functions.

## V. Next Steps

As described in the ALJ's February 26 ruling, a prehearing conference will be held on April 29 to discuss the scope of issues in the rulemaking proceeding and the process for addressing this Revised Straw Proposal. Opening comments on the Revised Straw Proposal are to be filed with the Docket Office and served on or before May 12. Reply comments are to be filed and served no later than May 30.

To promote a shared understanding of the terminology related to risk-informed decision making, SED will develop a proposed glossary of risk-related terms, modeled after the Department of Homeland

Security risk lexicon,[4] that will be provided to parties for comment and will be the subject of a future workshop.

[4] DHS Risk Lexicon, 2010 Edition, dated September 2010.

# Attachment A

## Proposed Schedule for GRC Phase 1

| Deadline | Activity | Time After Prior Activity (illustrative and not to conflict with calendar deadlines at left) |
|---|---|---|
| October 1 of Base Year | Utility provides RAPP submittal on operational lines of business | -- |
| November 1 | Utility and SED host public workshop on risk submittal | 30 days after submittal |
| March 1 of Base Year, Plus 1 | SED issues draft report(s) | 150 days after submittal |
| April 1 | SED hosts public workshop on draft report(s) | 30 days after issuance of draft report(s) |
| April 15 | Stakeholders provide comments on SED report(s) | 45 days after issuance of draft report(s) |
| May 15 | SED issues final report(s) | 30 days after receiving comments on draft report(s) |
| September 1 | Utility files GRC application, including possible changes from RAPP submittal | 105 days after issuance of final report(s) |
| October 1 | Utility hosts public workshop on overall GRC application | 30 days after filing of application |
| November 1 | SED issues verification that utility has addressed technical recommendations in SED Report(s) | 60 days after filing of application |
| January 15 of Base Year, Plus 2 | ORA submits report | 4.5 months after filing of application |
| February 1 | Other parties submit opening testimony | 2 weeks after ORA report |
| March 1 | Concurrent rebuttal testimony | 1 month after opening testimony |
| March/April | Public Participation Hearings | |
| March 15 – April 15 | Evidentiary Hearings, including SED participation | 2 weeks after rebuttal testimony |
| May 15 | Opening briefs | 1 month after end of hearings |
| June 7 | Reply briefs | 3 weeks after opening brief |
| July | Update testimony and hearings, if necessary | -- |
| November | Proposed decision | 5 months after reply briefs |
| December | Final decision | 1 month after proposed decision |

# Attachment B

# Streamlining

Keeping to a defined schedule and issuing a final decision prior to the test year is important for both operational and financial reasons. Operationally, the Commission and stakeholders need to keep to a timely schedule in order to (i) ensure that the data used to support Commission decision-making is not stale and (ii) enable the operational improvements proposed in these cases to be promptly implemented. Delayed cases also raise costs. Unpredictable schedules and uncertain funding hinder efficient project implementation. Further, increased administrative costs for the Commission, key stakeholders, and the utilities cause upward pressure on customer rates.

Therefore, the following elements should be implemented in order to streamline the major energy utilities' GRCs.

- Two ALJs should be assigned to the largest rate cases. The presence of two ALJs can facilitate case processing by dividing workload and minimizing delays caused by competing obligations, vacations or illness. Two ALJs can also allow for dual case tracks. For instance, one ALJ could be assigned during the RAPP phase and would be the lead ALJ for issues in the operational lines of business. A second ALJ could then be the lead for the support lines of business.

- Workshops and other informal discovery means should be encouraged. The utilities are encouraged to hold public workshops or other meetings to discuss issues of interest to the Commission and stakeholders. Such informal discovery can reduce (or at lease accelerate) more time-consuming discovery. Presiding Officers, as well as SED and Energy Division staff, are encouraged to attend workshops to facilitate gaining familiarity with the case and the key issues of interest to parties.

- The NOI should be eliminated. Although the presence of the NOI has likely contributed to a more complete record for the processing of GRCs, the amount of time required for the NOI is excessive and unwarranted. Further, the burden of proof is on the utility in GRCs. To the extent that the utility fails to meets its burden because of a flawed application, that risk should rest on the shoulders of the utility.

- The Master Data Request and regular reports should be rationalized. Currently, the utilities spend unnecessary effort on responding to the Master Data Request and preparing reports that are not effectively used by their expected audience. Similarly, recipients of these materials spend too much effort sorting through the materials to find information of particular interest. Therefore, the information requested in the Master Data Request and regular utility reports should be rationalized with an eye toward (i) reducing the amount of needless information provided by the utilities, (ii) ensuring the information is useful to its audience, and (iii) standardizing the presentation of information when possible to do so.

- Transparency between SED and the utility should be the focus of discovery during the RAPP. In order to promote an efficient RAPP process, the utilities should focus on SED discovery requests during the RAPP process, making discovery responses available to all interested parties. Additionally, the utility should provide its RAPP submittal to any interested party and the utility should address others' data requests as a secondary priority. Further, the utility should provide with its formal GRC application an exhibit showing any material changes made in the application to the programs described in the RAPP process. Such an exhibit will allow SED and stakeholders to make the most effective use of their review of the RAPP submittal.

- The Rate Case Plan should establish binding deadlines. Utilities should provide their RAPP submittals and formal GRC applications on calendar deadlines. To the extent that utilities wish to file on alternative dates, the utility shall seek leave to do so with the Executive Director. If the utility fails to meet the established deadline (or one extended by the Executive Director), the utility should face the prospect of penalties. Similarly, Commission staff and stakeholders shall be bound by the deadlines set forth in the Rate Case Plan and must seek leave from the Executive Director if unable to do so. Having established calendar date deadlines from year-to-year will allow for efficient planning. For example, planning for the assignment of ALJs and Commissioners can be done in advance, as can the scheduling of the prehearing conference. SED or other consultants known to be needed to review a utility submittal can be hired in advance. Similarly, staffing for cases, scheduling of vacations and even the reservation of hearing rooms and court reporters can be done in advance and no longer need contribute to delays.

- Prehearing procedural matters should be less time-consuming. With the deadlines established in advance by the Rate Case Plan, parties need not spend time in the early stages of a proceeding negotiating schedules. Rather, the time can be spent on more substantive matters and discovery. Similarly, planning for and attending prehearing conferences should go more quickly and the Scoping Memoranda can be issued more quickly.

- The protest period should be eliminated. Many parties' protests in the larger rate cases are perfunctory. The protests can be more efficiently replaced by a statement of interest of the party that is either provided in a prehearing conference statement or in that party's motion for party status.

- The burden of proof should be clarified as a matter of statewide policy and guidance provided to reduce the volume of data submitted by utilities. The data presented, and requested by intervenors, in the larger rate cases is increasing in a manner that threatens to overwhelm the Commission and many stakeholders. The increased volume, and concomitant case delays, are also contributing to higher costs. Therefore, the Commission should clarify that the burden remains on the utilities to support its forecasts by a preponderance of evidence and that once the utilities have made a prima facie showing, the burden shifts to intervenors to reverse the weight of the utilities' evidence. Furthermore, utilities and intervenors should support their arguments with facts, not mere opinion or disagreement. Arguments without evidence should be summarily rejected.

- Utilities should focus their testimony and workpapers on programs/projects of the greatest cost and importance. Information on smaller programs/projects can have the effect of distracting the Commission and interested parties from issues of greater importance. Therefore, the threshold for detailed program/project data should be increased from $1 million to $5 million in forecasted capital spending.