Appendix Q

PUBLIC POLICIES IN THE STATE OF CALIFORNIA

Ratemaking Regulatory Regime

Background on Gas Utility Ratemaking in CA and PG&E

The CPUC's authority to regulate electric, natural gas, and other public utilities subject to its jurisdiction derives from the California state constitution.[1] The California Public Utilities Code requires that all charges for service provided by a public utility be just and reasonable.[2] Pursuant to this authority, the CPUC determines reasonable operational costs, customer cost allocations and rate design for the gas utility operations gas utilities, including PG&E.[3]

Costs incurred by California utilities to provide services to customers fall into the following major categories: gas procurement costs for core customers (primarily residential and small commercial customers);[4] utility operating costs, and gas public purpose program costs.[5] Each of these categories is subject to a different ratemaking proceeding. Discussed below are the ratemaking process and issues pertaining to costs PG&E incurs to operate its distribution, transmission and storage facilities.

The purpose of a rate case is to establish rates that will enable it to recover its authorized revenue requirement, *i.e.*, the revenues needed to cover the costs of operating natural gas distribution, transmission and storage systems and earn a rate of return (profit).[6] During the ratemaking process, costs are allocated among customer customers and then rates applicable to individual customer classes are developed.

PG&E uses two different proceedings to establish its authorized revenue requirement for its gas distribution and for its transmission and storage services. Its gas distribution revenue requirement is established in a general rate case (GRC), with cost allocation and retail distribution rates determined in a separate biennial cost allocation proceeding. The revenue requirement and rates for PG&E's transmission (backbone and distribution) and storage

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[1] CA Const. Art. XII, § 6.
[2] Cal. Public Utilities Code § 451.
[3] California Public Utilities Commission, Electric & Gas Utility Cost Report; Public Utilities Code Section 747 Report to the Governor and Legislature at 30 (Apr. 2011) (hereinafter referred to as the "Section 747 Report").
[4] Noncore natural gas customers, generally electric generators or industrial customers, generally purchase their gas supplies from third parties, rather than from the utility. Section 747 Report at 31.
[5] Section 747 Report at 30. Gas Public Purpose Programs fall into three main categories: energy efficiency and low income energy efficiency; the subsidy for California Alternative Rate for Energy (CARE); and the California Energy Commission's gas public interest research and development program. Costs associated with these programs are determined in various CPUC proceedings. Section 747 Report at 33.
[6] *See* Section 747 Report at 4.

services are established in "Gas Accord" proceedings. Gas Accord and GRC proceedings follow similar procedural tracks and establish rates for rate cycles extending three to four years.

When filing a rate case, PG&E projects future costs for the applicable rate cycle, which includes a "test year" and two or three "post test years," or attrition years. The utility provides five years of historical cost data.[7] Interested parties, including the CPUC's Division of Ratepayer Advocates (DRA) routinely intervene and actively participate. DRA, created under section 309.5 of the Public Utilities Code, "represents and advocates on behalf of the interests of public utility customers," with the goal of "obtain[ing] the lowest possible rate for service consistent with reliable and safe service levels."[8] Like other parties, DRA staff engages in discovery, files testimony, participates in evidentiary hearings, and engages in settlement negotiations.

The Energy Division is not a party to these rate cases, but provides technical assistance and advice to the presiding administrative law judge (ALJ) and the Commissioners. Energy Division staff keep apprised of developments in a rate case, but because of their role in assisting the ultimate decision-makers, do not interact with DRA.

CPSD staff of the CPSD traditionally has had little involvement in natural gas utility ratemaking proceedings. The CPSD staff has expressed its desire, however, to increase interaction with DRA and Energy Division Staff to assist them in understanding utility maintenance requirements and expenditures in gas rate cases. More recently, the CPSD staff has increased its outreach efforts to DRA and the Energy Division for the purpose of helping them to understand maintenance, repair, and replacement costs. The CPSD's limited role in gas utility ratemaking proceedings is not unusual when compared to practices in other states.[9]

Utility rate cases typically are resolved through settlement among the parties, often after the completion of evidentiary hearings. The CPUC approves a rate settlement if it is "reasonable in light of the whole record, consistent with the law, and in the public interest.[10]

Overview of PG&E's Ratemaking Proceedings

The Revenue requirement and rates for PG&E's transmission and storage services are established in its Gas Accord proceedings. On April 18, 2011, the CPUC accepted a settlement that will establish PG&E's revenue requirements for these services for the 2011–2014 rate

[7] Rule 3.2 of the CPUC's Rule of Practice of and Procedure set forth the information a utility must submit with an application for authority to increase its rates.
[8] Cal. Public Utilities Code § 309.5(a).
[9] Based on conversations with staff at several state agencies, formal involvement by pipeline safety staff in a utility ratemaking case appears to be rare. Rather, state safety personnel appear to generally serve as informational resources, with a couple states indicating that state safety personnel have limited or no involvement in utility ratemaking processes.
[10] CPUC Rule of Practice and Procedure Rule 12.1(d)

cycle.[11] A settlement approved on May 13, 2011 in PG&E's 2011 General Rate Case (GRC 2011) established the utility's distribution revenue requirements for the 2011-2013 rate cycle.[12]

Both settlements provide for capital project expenditures involving new pipeline facilities and contain new ratemaking mechanisms for expenses associated with pipeline safety and reliability. In addition, both settlements contain extensive new pipeline safety reporting requirements. Below is an overview of the two rate proceedings, particularly their treatment of costs related to pipeline integrity management and reliability and reporting requirements.

PG&E's Gas Accord V. PG&E submitted its Gas Accord V rate filing in 2009 and filed a proposed settlement in August 2010, one month before the San Bruno accident. Following the accident, the presiding ALJ added a "safety phase" to the proceeding to address pipeline safety measures and emergency response procedures that PG&E should be required to implement to ensure the safe and reliable operations of its transmission and storage facilities.[13] In addition, the Gas Accord V Decision modified PG&E's settlement to require extensive pipeline safety reporting requirements.[14]

The Gas Accord Decision approved a revenue requirement for 2011 of $514.2 million, which will increase to $581.8 million by 2014.[15] The decision also approves capital expenditures for new pipeline and pipeline upgrades, providing PG&E with 100% and 98% of the capital investment it requested for pipeline integrity and pipeline safety and reliability, respectively.[16] Major Work Category 98 (MWC-98) addresses "Gas Transmission Pipeline Integrity Management" and identifies capital funds needed under federal pipeline integrity management requirements,[17] especially to upgrade PG&E's transmission pipelines to accommodate in-line inspections.[18] Major Work Category 75 (MWC-75) addresses "Pipeline Safety and Reliability," and covers capital costs associated with PG&E's replacement of high-risk pipeline segments and pressure regulating facilities identified under PG&E's Risk Management Program.[19] The Gas Accord Decision also approves eight planned transmission capital projects that will be given "adder" treatment. If PG&E constructs these identified projects, the costs (up to a cap) will be added to PG&E's rates starting on January 1 following the project's in-service date.

The Gas Accord V Decision also approved a negotiated level of operation and maintenance expenses for each year of the rate cycle, including expenses associated with compliance with the Department of Transportation's (DOT) transmission integrity management regulations.[20]

[11] Decision Regarding the Gas Accord V Settlement, D.11-04-031 (Apr. 18, 2011) (Gas Accord V Decision).
[12] Decision Regarding 2011 GRC, D.11-05-018 (May 13, 2011).
[13] Revised Scoping Memo and Ruling Adding an Additional Phase, A.09-09-013, (Oct. 15, 2010).
[14] Gas Accord V Decision at 16
[15] Gas Accord V Decision at 23.
[16] Gas Accord V Decision at 27.
[17] 49 C.F.R. Part 192, Subpart O (2009).
[18] Gas Accord V Decision at 24-25 & Settlement Section 7.2.
[19] Gas Accord V Decision at 26-27.
[20] Section 7.3.1 of the Settlement. In 2011, authorized O&M expenses associated with integrity management are $22

For these costs, the decision approved a new Integrity Management Expense Balancing Account (IMEBA), which is a one-way downward balancing account in which PG&E will record the aggregate difference between the authorized revenue requirement and expenses incurred over the term of the settlement. At the end of the settlement period, accumulated account balances are returned to customers, with interest. Reflecting a concern that in the past, PG&E has not always spent all funds authorized for certain projects, the CPUC's decision explains that the one-way balancing account is designed to "help ensure that PG&E spends all of the designated O&M monies for pipeline integrity management activities."[21] There is no provision for PG&E to recover expenses that exceed authorized amounts, even if prudently incurred.

Reflecting the renewed focus on pipeline safety issues in the aftermath of the San Bruno accident and to establish a mechanism for verifying that PG&E spends authorized funds for their intended purposes during the rate cycle, the CPUC's Decision requires that PG&E submit a semi-annual "Gas Transmission and Storage Safety Report" to the directors of the Energy Division and CPSD.[22] The report must provide adequate information to enable staff to (1) monitor PG&E's activities and expenditures related to storage and pipeline-related safety, reliability and integrity capital projects and maintenance; (2) determine whether PG&E is completing projects identified as high risk or undertaking other high risk projects instead; (3) determine PG&E's reasons for any project reprioritization; and (4) monitor PG&E's compliance with federal integrity management regulations (Part 192, subpart O).[23] The CPUC's Decision further requires that, if the CPSD identifies problems with PG&E's prioritization or administration of projects, the CPSD shall notify the CPUC.[24]

The Safety Phase of the Gas Accord V proceeding remains pending before the CPUC and will address how safety concerns on PG&E's system can be avoided over 4-year rate cycle and beyond. In February 2011, the presiding ALJ issued a ruling stating that he would prepare a proposed decision recommending safety-related protocols and procedures that PG&E should be required to implement.[25]

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million and escalate each year of the rate cycle by up to 2.6%.

[21] Gas Accord V Decision at 56. The settlement provided PG&E with 92% of its requested expenditures for pipeline integrity operations and maintenance expenses. *Id.* at 27.

[22] Gas Accord V Decision at 58; Settlement, Appendix C.

[23] Gas Accord V Decision at 58; Settlement, Appendix C.

[24] Gas Accord V Decision at 58-59.

[25] Assigned Comm'r & ALJ's Ruling Confirming e-mail Ruling & to Address Whether Proposed Settlement is Adequate in Terms of Pipeline Safety, Integrity, & Reliability Efforts, A.09-09-013 at 3 (Sept. 15, 2010) (Safety Phase Ruling). Those protocols and procedures included the following: PG&E's disaster and emergency response plan (PG&E's Pipeline 2020 Program, which involves expanded use of automatically or remotely operated shut-off valves, and work with local communities, public officials and first responders); steps PG&E has taken to inform local emergency personnel about availability and location of transmission lines and shut-off valves and whether additional information needed; frequency of testing or monitoring of shut-off valves; procedures PG&E should have to ensure timely notification to the CPUC of any reprioritization of capital expenditures associated with transmission lines and procedures CPUC staff should adopt to review and monitor the reprioritization of these capital expenditures; other safety-related protocols/procedures that should be required; and the need for workshops and/or evidentiary hearings to determine protocols/procedures PG&E should be required to implement during rate cycle.

PG&E's GRC 2011 Rate Proceedings: On May 13, 2011, the CPUC issued an order approving, with modification, PG&E's proposed GRC 2011 settlement.[26] The settlement establishes a gas distribution revenue requirement of $1,131 million for 2011, reflecting a $47 million (4.3%) increase.[27] By 2013, the total distribution revenue requirement will increase by a total of $246 million, which is $540 million less than PG&E requested in its application.[28] The settlement reflects a revenue requirement of $258 million for gas distribution capital expenditures in 2011, and expenditures of $196 million for expenses.[29] Attrition year increases will be implemented through the CPUC's Advice Letter process.[30]

With respect to pipeline safety expenditures, PG&E's settlement creates a Major Work Category for expenses incurred to comply with DOT's distribution integrity management program (DIMP) regulations.[31] PG&E would be required to establish a new one-way balancing account mechanism with a $60 million cap over the term of the GRC rate cycle, 2011-2013. PG&E will track DIMP expenditures over the course of the rate cycle and return to ratepayers any portion of the $60 million not spent at the end of the period.[32] Like the Gas Accord V settlement, the GRC 2011 settlement is silent regarding PG&E's ability to recover DIMP expenditures over $60 million.

The CPUC's decision accepting the settlement expresses concern that PG&E will reprioritize contemplated programs and projects in a way that is neither reasonable nor consistent with expenditures contemplated in and approved by the settlement. While acknowledging the utility's prerogative and responsibility to reprioritize and defer activities as needed to ensure safe and reliable service, the decision emphasizes that the CPUC must be assured that the utility spends the funds necessary to ensure such safe and reliable service. Moreover, the CPUC expressed concern that, even if reprioritizations and deferrals are justified, they may not have been tested in the GRC process and may not reflect the most efficient use of funds.[33]

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[26] GRC 2011 Decision at 88-89.
[27] GRC 2011 Decision at 15 & Attachment 1 at 1-4 (Settlement at Section 3.1).
[28] GRC 2011 Decision at 19.
[29] PG&E GRC 2011 Settlement at Section 3.3.1. By comparison, the settlement in PG&E's GRC 2007 rate case authorized PG&E's fully requested amount of $205.6 million in 2007 for gas distribution capital expenditures, including $66.953 million for its Gas Pipeline Replacement Program (GPRP) and $15.8 million to maintain and enhance the gas distribution infrastructure. The CPUC Decision approving the GRC 2011 settlement noted that, in the past, PG&E's actual expenditures sometimes had fallen short of those budgeted, and required that PG&E use all funds provided in the settlement. If it did not, PG&E was required to provide full explanation in its next GRC. Opinion Authorizing Pacific Gas & Electric Company's General Rate Case Revenue Requirement for 2007-2010, D.07-03-044 at 80-83 (March 15, 2007). In its GRC 2011 application, PG&E explained that it did not spend the full $66.953 during 2007 and 2008, because its risk analysis indicated a need to establish a Copper Service Replacement Project (CSRP). PG&E, therefore, allocated some funds from the GPRP to the CSRP. Application of PG&E for Authority, Among Other Things, to Increase Rates & Charges for Elec. & Gas Service Effective on January 1, 2011, Exhibit PG&E-3, Ch. 17 (Testimony of Robert T. Fassett) at 19-6 to 19-7 (Dec. 21, 2009).
[30] The CPUC's advice letter process provides a utility a "quick and simplified review" of non-controversial utility requests. CPUC General Order 96-B at 2, 8.
[31] 49 C.F.R. §§ 192.1001-15 . The federal DIMP regulations, which are discussed more fully in section 7.2.3, become effective August 2011.
[32] PG&E GRC 2011 Settlement at Section 3.3.2.
[33] GRC 2011 Decision at 26-31.

Therefore, the CPUC required that PG&E provide detailed information about pipeline safety-related expenses and capital expenditures. In particular, in 2011, PG&E must submit to the CPUC the company's authorized budgeted amounts for 2011 and explain any differences with assumptions reflected in the Settlement Agreement. In 2012 and 2013, PG&E must provide authorized budgeted amounts for the year and explain any significant deviations between the authorized budget for the prior year. In addition, in its next GRC, PG&E must submit extensive information fully describing any reprioritizations or deferrals, explaining the reprioritization process, justifying specific deferrals, and justifying activities and projects given a higher priority that were not identified in the 2011 GRC. The decision cautions that, for activities deferred and then re-requested in the next GRC, the CPUC will be "critical in its evaluation."[34]

Finally, in light of the San Bruno accident, the GRC Decision requires that PG&E submit a substantial amount of pipeline safety-related information to the CPSD and Energy Division on a semi-annual basis. As more fully discussed below, the reports must include (1) a "thorough description and explanation" regarding the decision-making process for identifying/ranking capital projects, operation and maintenance activities, and inspections undertaken for gas distribution pipeline safety, integrity and reliability; (2) detailed information regarding amounts budgeted and spent and specific detail on capital and O&M projects; and (3) project descriptions and status.[35]

One-Way Balancing Accounts for Pipeline Integrity Management and Reliability Expenses

The settlements in the Gas Accord V and GRC 2011 proceedings permit PG&E to recover capital costs, including infrastructure replacement costs, associated with pipeline integrity programs and reliability improvements through base rates. To track integrity management expenses, however, the settlements establish new one-way balancing mechanisms. Under such mechanisms, PG&E records as a credit the annual revenue requirement authorized under each settlement and then debits expenses as incurred. At the end of the rate cycle, PG&E is required to transfer any accumulated credit balance to core and non-core customers. The purpose of one-way balancing accounts is to ensure that PG&E spends all designated amounts authorized for these purposes.[36] One-way balancing accounts differ from two-way balancing accounts in that a one-way balancing account does not provide the utility opportunity to recover expenses above initial authorized amounts, even if such costs are prudently incurred.

According to CPUC staff, under a one-way balancing account, the parties establish an agreed-upon reasonable forecast of costs associated with a targeted program, such as integrity

[34] GRC 2011 Decision at 30.
[35] GRC 2011 Decision at 31 & Attachment 5.
[36] Gas Accord V Decision at 56. Southern California Gas Company's 2008 GRC also contained a one-way balancing account for distribution integrity management costs. Southern California Gas Company is proposing to eliminate the account in its 2012 GRC.

management.[37] Recognizing that a utility has the discretion to spend funds, a one-way balancing account is designed to ensure that money is spent for the purpose intended and that all of the designated funds are spent. A utility cannot recover any costs above those initially authorized. As such, from parties' perspectives, one of the attractive features of a one-way balancing account is that it avoids time-consuming prudence reviews of costs that exceed authorized amounts.

Order Instituting Rulemaking on New Safety and Reliability Regulations

In the wake of the San Bruno accident, the CPUC has initiated a comprehensive review of its natural gas pipeline safety regulations, including the role of ratemaking in utility's implementation of pipeline safety programs. The proceeding is intended to be "a forward-looking effort to establish a new model of natural gas pipeline safety regulation applicable to all California pipelines."[38] The scope of the OIR is broad and identifies several "primary objectives," including (1) "[d]evelop and adopt safety-related changes to the Commission's regulation of natural gas transmission and distribution pipelines, including requirements for construction, especially shut-off valves [sic], maintenance, inspections, operations, record retention, ratemaking, and application of penalties;" and (2) "[c]onsider available options for the Commission to better align ratemaking policies, practices, and incentives to elevate safety considerations, and maintain utility management focus on the 'nuts and bolts' details of prudent utility operations."[39]

The OIR proposes several near-term modifications to existing pipeline safety regulations affecting strength testing and reporting requirements. In addition, the OIR identifies twelve topics on which the CPUC is considering new rules.[40] With respect to ratemaking, the OIR

[37] There is at least one proposal before the California legislature that would codify one-way balancing accounts. California Assembly Bill (AB) 56 would require, among other things that a public utility return ratepayer funds that were approved for expenditure for public safety if those funds are not expended within a reasonable period of time. A.B. 56, 2011-12 Reg. Sess. (Cal. 2010).

[38] Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms, R.11-02-019 at 1 (Feb. 25, 2011).

[39] OIR at 4. Other objectives include Provide the public with a means to make their views known to the CPUC; provide the public with the IRP's expert recommendations regarding the technical explanation for the explosion, assessment of likelihood that similar events may occur, and recommendations for preventive measures and other improvements; consider ways that the CPUC can undertake a comprehensive risk assessment for all regulated natural gas pipelines, and possibly for other industries that the CPUC regulates. consider the appropriate balance between the CPUC's obligation to conduct its proceedings in a manner open to the public with the legitimate public safety concerns that arise from unlimited availability of certain utility information; consider if the CPUC needs further rules or other protection for whistleblowers to inform the Commission of safety hazards; and expand emergency and disaster planning coordination with local officials. OIR at 4-5.

[40] OIR, Attachment B. Those topics include: retrofitting transmission lines to allow in-line inspections; requiring evaluations for installing automatic or remote controlled valves on transmission lines; strengthening emergency response procedures; gas control monitoring (prevent liquid intrusion and sulfur buildup); test requirements for pipes below 100 psig and service lines; clearance between gas pipelines and other subsurface structures; incorporating one-call requirements for marking underground facilities; reporting CP deficiencies and providing a timetable for remedial actions; cover requirements for transmission lines; reporting problems associated with mechanical/compression couplings; assessment of meter set assemblies and other pipeline components to protect

expresses the need for certainty that expenditures authorized for maintenance and capital projects are carried out by the utility. In this regard, the OIR indicated that one of the measures to be considered is whether "special ratemaking 'feedback loop' for safety-justified expenditures…" should be implemented to ensure that such expenditures are in fact made, or substituted only with higher priority safety projects.[41]

Comments on the ratemaking aspects of the OIR reflect two approaches. DRA, for example, appears to advocate expanding the use of one-way balancing accounts for "specific safety and/or maintenance related expense categories and investment programs."[42] Southern California Gas Company and San Diego Gas & Electric Company, on the other hand, urge a "balanced ratemaking framework" that encourages utilities to implement safety practices, while preserving shareholders' ability to earn a reasonable return.[43] In this regard, SoCalGas/SDG&E urge the CPUC to convene a "collaborative workshop" to explore potential proposals and their impact on, among other things, "alignment of utility incentives and Commission policies…"[44] As an interim measure, SoCalGas/SDG&E urge that the CPUC authorize a Pipeline Safety and Reliability Memorandum Account[45] to enable utilities to track safety and reliability costs that were not contemplated in their GRCs.[46]

PG&E expresses similar views, in particular, its expectation that the CPUC will allow utilities to recover compliance costs in their rates. Like SoCalGas/SDG&E, PG&E recommends that the CPUC authorize memorandum accounts to track costs associated with compliance with the new rules.[47]

On May 10, 2011, the Administrative Law Judge presiding in this proceeding issued a proposed decision that, if adopted, would require that operators of natural gas transmission pipelines in California (including PG&E) to prepare and file comprehensive Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plans to either pressure test or replace those pipeline segments that have never been pressure tested or that lack sufficient

from excessive snow and ice loading; and require operators to identify threats along pipelines and develop plan to mitigate them, including R&D.

[41] OIR at 12.

[42] Comments of the Division of Ratepayer Advocates on Order Instituting Rulemaking, R.11-02-019, at 3 (Apr. 13, 2011).

[43] Comments of Southern California Gas Co. and San Diego Gas & Elec. Co. on Order Instituting Rulemaking, R.11-02-019 at 11 (Apr. 13, 2011).

[44] Comments of Southern California Gas Co. at 11.

[45] "A memorandum account allows a utility to track costs arising from events that were not reasonably foreseen in the utility's last general rate case. By tracking these costs in a memorandum account, a utility preserves the opportunity to seek recovery of these costs at a later date without raising retroactive ratemaking issues. However, when the Commission authorizes a memorandum account, it has not yet determined whether recovery of booked costs is appropriate, unless so specified." CPUC, Energy Division, Resolution G-3453 at 2 n.2 (May 5, 2011) (citing D.10-04-031 mimeo at pp. 43-44).

[46] Comments of Southern California Gas Co. at 11.

[47] Comments of Pacific Gas and Elec. Co. on Order Instituting Rulemaking, R.11-02-019 at 25-26 (Apr. 13, 2011).

detail related to the performance of a test.[48] The required implementation plans would be required to provide for testing or replacement as soon as practicable and include interim safety enhancement measures, including increased patrols and leak surveys, pressure reductions, prioritization of pressure testing for critical pipelines that must run at or near MAOP values which result in hoop stress levels at or above 30% SMYS, and other safety enhancement measures.

Implementation Plans would be required to (1) list all transmission pipeline segments not previously pressure tested, with prioritized designations for replacement or pressure testing; (2) set forth criteria used to identify which pipeline segments will be replaced instead of pressure tested; and (3) prioritize replacements and explain prioritization criteria. Before Implementation Plans are filed, the CPUC would convene technical workshops, facilitated by an administrative law judge, to discuss and provide recommendations to inform the prioritization of pipeline segments for replacement or testing. The workshops also would be critical to developing a sound engineering approach to address the issue of aging transmission lines that have not been pressure tested.

Finally, to enable the CPUC to fully consider the effects of the final adopted Implementation Plans, each plan would be required to provide cost estimates and information on rate impacts. Each Implementation Plan would be required to include a ratemaking proposal that contains (1) specific rate base and expense amounts for each year proposed to be included in regulated revenue requirement; (2) proposed rate impacts for each year and each customer class; (3) other facts and information necessary to understand the comprehensive rate impact of the Implementation Plan. PG&E's plan must also include a proposal for sharing costs between ratepayers and shareholders.

Contrast Recovery of Integrity Management Costs to FERC and Other States

A key characteristic of one-way balancing accounts is that they preclude the utility from recovering integrity management expenses that exceed authorized forecasted amounts, even if those costs are prudent. The practice of using one-way balancing account treatment for expenses associated with compliance with federally mandated integrity management safety programs does not appear to be widespread.[49]

[48] Proposed Decision Determining Maximum Allowable Operating Pressure Methodology and Requiring Filing of Natural Gas Transmission Pipeline Replacement or Testing Implementation Plans, Filed in OIR 11-02-019 (May 10, 2011).
[49] This section focuses on expenses related to integrity management activities, not capital costs. With respect to capital costs, the Gas Accord V and GRC 2011 settlements allow PG&E to recover the prudently incurred capital costs associated with pipeline upgrades and replacements and do not place PG&E at risk for these costs via a one-way balancing mechanism. Although a number of states have adopted statutory and regulatory mechanism designed to ensure that pipelines can recover capital improvement costs, to date, the CPUC has not placed PG&E at risk for recovering them via a one-way balancing mechanism.

The Federal Energy Regulatory Commission: Pursuant to section 4 of the Natural Gas Act (NGA), the Federal Energy Regulatory Commission (FERC) is charged with ensuring that the transportation and sales rates of interstate natural gas pipelines are just and reasonable.[50] An interstate pipeline's revenue requirement is based on projected units of service.[51] A pipeline filing a rate case must submit cost and revenue data for a 20-month test period, which can be adjusted for known and measurable changes.[52]

Pipeline section 4 rate cases are vigorously scrutinized by customers and usually entail extensive discovery. In addition, the parties often may file written testimony. Most interstate pipeline rate cases settle before an evidentiary hearing is convened. Usually, rate cases do not identify expenses associated with integrity management programs. Rather, these costs are embedded in the pipeline's cost of service and recovered through generally applicable rates. PHMSA does not participate in pipeline rate cases at FERC.

Interstate natural gas pipelines are not required to file rate cases and years may elapse between rate cases.[53] In the meantime, a pipeline is at risk for under recovering costs, but also retains any over-recovery.[54] The Commission has found that this gives the pipeline an incentive to minimize costs and maximize service.[55] Pipelines do not report, and FERC does not audit, safety expenditures after the conclusion of a rate case or in a future rate case.

Interstate pipelines are at risk for cost recovery between rate cases, therefore, the FERC generally disfavors cost trackers because they would guarantee recovery.[56] Consequently, to date, the Commission has approved tracking mechanisms for pipeline safety compliance expenses only in the context of settlements. For example, Equitrans, L.P. is authorized to recover via a tracker expenses, and return, taxes and depreciation expense on capital investments associated with compliance with the Pipeline Safety Improvement Act of 2002.[57] The Commission also has approved settlements containing "capital surcharge" trackers, allowing a pipeline to recover certain qualifying costs incurred for system security and pipeline integrity costs.[58]

State Cost Recovery Mechanisms. As at FERC, a significant number of rate cases at state commissions are resolved by settlement and orders approving settlements do not necessarily

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[50] 15 U.S.C. § 717 et seq. (2006).
[51] 18 C.F.R. § 284.10(b)(3) (2010).
[52] *See generally*, 18 C.F.R. §§ 154.301-315 (2010).
[53] The FERC may, however, initiate a rate case under NGA § 5, in which FERC has the burden of demonstrating that the pipeline's existing rates are unjust and unreasonable.
[54] *Canyon Creek Compression Co.*, 99 FERC ¶ 61,351 at PP 14-15 (2002).
[55] *Canyon Creek*, 99 FERC ¶ 61,351 at PP 14-15.
[56] *canyon Creek*, 99 FERC ¶ 61,351 at PP 14-15; *ANR Pipeline Co.*, 70 FERC ¶ 61,143 (1995).
[57] *Equitrans, L.P.*, 115 FERC ¶ 61,007 (2006).
[58] *Florida Gas Transmission Co.*, 109 FERC ¶ 61,320 (2004) (authorizing reservation surcharge to recover certain capital costs incurred for system security and pipeline integrity). *El Paso Natural Gas Co.*, 120 FERC ¶ 61,208 (2007) (authorizing volumetric surcharge to recover the cost of service effect of capital and related Operation and Maintenance expenses in connection with pipeline integrity program). These surcharges have expired.

discuss treatment of integrity management expenses as a separate cost item. To the extent, however, that cases address integrity management expenses as a separate expense item, use of one-way balancing accounts does not appear to be common. In 2005, The Michigan Public Service Commission (MPSC) established this type of a provision for a utility's "uncharacteristic" and "extraordinary" safety and training-related expenses that were not known and measurable.[59] The MPSC required that the utility submit an annual report on the status of program expenditures specifically identifying those related to safety and training-related activities. The MPSC would then review the expenditures to determine if a refund were appropriate.[60] Importantly, the one-way balancing account approved by the Michigan PSC differs from those reflected in PG&E's settlements, in that refunds of expenditures are not automatic.

Tracker mechanisms also have been utilized to recover integrity management expenses. Since 2004, Indiana Gas Company has been authorized to adjust its rates via a Pipeline Safety Adjustment to recover prudently incurred, incremental non-capital expenses, up to a specified cap. The utility must demonstrate that costs are clearly and convincingly demonstrated to be incremental and caused by the Pipeline Safety Improvement Act of 2002 (*i.e.* transmission integrity management costs).[61] Costs exceeding the cap are deferred for subsequent recovery, without carrying costs, either in a subsequent tracker where costs are below the cap, or in a future rate case. The mechanism was extended and modified in 2008 and extended again in 2011, and now includes a provision allowing the utility to amortize certain deferred balances identified three-year periods, without regard to the cap.[62] In 2010, the mechanism was modified to include deferred DIMP planning expenses.[63]

Current and Proposed Reporting Requirements

In the wake of the San Bruno accident and concerns that PG&E had reprioritized projects and deferred the completion of pipeline safety and reliability projects that had been identified during rate cases as "high risk," no fewer than three proceedings either propose or have adopted extensive reporting requirements for PG&E. The Gas Accord V decision requires that PG&E submit a semi-annual "Gas Transmission and Storage Safety Report" (Safety Report), and the GRC 2011 Decision requires that PG&E submit gas distribution reports. In addition, the OIR proposes to require the submission of reports to the CPUC.

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[59] *Michigan Consolidated Gas Co.*, Opinion and Order Granting Rate Relief, Case No. U-13898 at 74-76 (Apr. 28, 2005).
[60] *Michigan Consolidated Gas Co.* at 76.
[61] Indiana Gas Co. D/B/A Vectren Energy Delivery of Indiana, Cause No. 42598 (Nov. 30, 2004). The mechanism was modified and extended in 2008, Indiana Gas Co. D/B/A Vectren Energy Delivery of Indiana, Cause No. 43298 (Feb. 13, 2008), and extended again in 2011. Indiana Gas Co. D/B/A Vectren Energy Delivery of Indiana, Cause No. 43967 (Apr. 5, 2011).
[62] Indiana Gas Co. D/B/A Vectren Energy Delivery of Indiana, Cause No. 43967.
[63] Indiana Gas Co. D/B/A Vectren Energy Delivery of Indiana, Cause No. 43885 (Sept. 8, 2010).

The Gas Accord V and GRC 2011 settlements contain numerous reporting requirements applicable to PG&E's transmission and storage facilities and gas distribution facilities. The reporting requirements are similar. Generally, PG&E must:

- provide a "thorough description and explanation of the strategic planning and decision-making approach" used to determine and rank safety, integrity, and reliability projects, operation and maintenance activities and inspections;[64]

- provide specific information regarding funds budgeted and spent regarding pipeline safety, integrity and reliability capital expenditures and operation and maintenance expenses each year and throughout the rate period, and an explanation for any funds budgeted that are not spent;

- provide detailed information regarding projects undertaken; projects completed or not completed; costs of projects and how they compare to information contained in the Settlement Agreements; whether projects were completed pursuant to any federal requirement;

- provide its most recent Risk management Top 100 Report and identify any changes to it and reasons for them;

- provide its most recent inspections plans, explain progress of performing inspections, their results and inspection methods, and explain any discrepancies found in pipeline records; and

- discuss the status of compliance with federal pipeline integrity management regulations.

In addition, the OIR would require that pipeline operators report incidents that meet certain criteria, provide quarterly summary reports on gas leak related incidents,[65] submit installation reports regarding new pipeline construction and reconstruction or reconditioning of existing pipeline to be operated at a hoop stress of 20 percent or more of SMYS.[66]

Most, if not all, of this information is to be submitted to the directors of the CPSD and Energy Division. The staff's of both divisions indicated that they were involved in developing these requirements, but expressed concern about whether they have resources adequate to review and evaluate the information and take any action based on it.[67]

[64] Gas Accord V Decision Appendix C at 1; Proposed ALJ Decision Attachment 5 at 1.
[65] OIR, Attachment B.
[66] OIR, Attachment C.
[67] Interview of CPSD, March 29, 2011; Interview with Energy Division, Mar. 29, 2011.