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Exhibit Number	:	ORA-10
Commissioner	:	C. Peterman
ALJ	:	J. Wong
Witness	:	P. Sabino

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Report on the Results of Operations for Pacific Gas and Electric Company Test Year 2015 Gas Transmission and Storage Rate Case

Chapter 10
Gas System Operations
With Errata
CLEAN Version

San Francisco, California
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I. INTRODUCTION

This exhibit presents the analyses and recommendations of the Office of Ratepayer Advocates (ORA) regarding Pacific Gas and Electric Company's (PG&E) "Gas System Operation Expenses and Capital Expenditures" proposals associated with its Test Year (TY) 2015 Gas Transmission and Storage (GT&S) rate case.

Specifically, this exhibit addresses PG&E's forecasts of "Gas System Operations" expenses for 2015 and capital expenditures for 2013 through 2015. "Gas System Operations" expenses and capital expenditures are for work activities related to ensuring that the gas transmission and storage system has sufficient capacity to meet customer demands safely and reliably.[1]

PG&E's activities and costs are grouped with similar types of work into a Major Work Category (MWC). PG&E's forecasts for MWC expenses are expressed in SAP nominal dollars. SAP dollars include certain labor-driven adders such as employee benefits and payroll taxes that are charged to separate Federal Energy Regulatory Commission (FERC) accounts. ORA's recommendations are made by MWC and SAP nominal dollars which are then translated into the appropriate FERC accounts through the Results of Operations (RO) model.

II. SUMMARY OF RECOMMENDATIONS

The following summarizes ORA's recommendations regarding the "Gas System Operations" O&M expenses for Test Year 2015:

- Adopt and approve ORA's forecast amount of $17,504,900 for Test Year 2015 for Gas System Operations expense (MWC CM) by adjusting the PG&E forecast amount of $17,935,000 and removing a total of $430,100 in 2015;
- Adopt and approve ORA's forecast amount of $7,310,870 for Test Year 2015 for GT Marketing/Sales/Strategy expense (MWC CX) by adjusting the PG&E forecast amount of $7,490,000 and removing a total of $179,130 in 2015;
- Adopt and approve ORA's forecast amount of $18,241,252 for Test Year 2015 for Compressor Fuel and Power expense (MWC JT) by adjusting the

[1] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-1.

PG&E forecast amount of $19,124,000 and removing a total of $882,748 in 2015; and

- Adopt and approve ORA's forecast amount of $3,088,525 for Test Year 2015 for Greenhouse Gas Emissions expense (MWC JT) by adjusting the PG&E forecast amount of $3,191,375 and removing a total of $102,850.

The following summarizes ORA's recommendations regarding the "Gas System Operation" capital expenditures for Test Year 2015:

- Adopt and approve ORA's forecast amount of $6,069,219 for Test Year 2015 for "New Business" capital expenditures (MWC 26) by adjusting the PG&E forecast amount of $8,560,000 and removing a total of $2,490,781 in 2015 from PG&E's forecast;
- Adopt and approve ORA's forecast amount of $1,338,896 for Test Year 2015 for "Meter Sets – Power Plant" capital expenditures (MWC 26) by adjusting the PG&E forecast amount of $1,617,840 and removing a total of $278,944 in 2015 from PG&E's forecast;
- Adopt and approve ORA's forecast amount of $2,758,005 for Test Year 2015 for "Vintage Pipe Replacement Betterment" capital expenditures (MWC 73A) by adjusting the PG&E forecast amount of $7,051,620 and removing a total of $4,293,615 in 2015 from PG&E's forecast;
- Adopt and approve ORA's forecast amount of $2,665,000 for Test Year 2015 for "New Capacity Projects" capital expenditures (MWC 73A) by adjusting the PG&E forecast amount of $42,463,592 and removing a total of $39,798,592 in 2015 from PG&E's forecast;
- Authorize the continuation of the programmatic implementation of PG&E's new Normal Operating Pressure (NOP) and Overpressure Protection (OPP) policies over the entire PG&E gas transmission system.[2]
- Adopt and approve ORA's forecast amount of $2,302,560 for Test Year 2015 for "NOP Reductions" capital expenditures (MWC 73A) by adjusting the PG&E forecast amount of $10,897,174 and removing a total of $8,034,830 in 2015 from PG&E's forecast;
- Deny the PG&E proposal to equalize the Redwood and Baja rates for Core and Noncore customers, and instead adopt ORA's recommendation to maintain the traditional cost-differentiated rate design;
- Support the PG&E proposal to maintain the existing traditional Gas Accord cost allocation methodologies for its backbone transmission, local transmission, gas storage facilities, and transmission-level customer access charges;

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[2] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-2.

- Deny the PG&E proposal to allocate additional storage capacity to load balancing for injection and withdrawal; and
- ORA does not oppose the implementation of the projects subject to the specific cost recommendations regarding the project expenses and capital expenditures which are addressed in various ORA Exhibits, including ORA Exhibit 11 by ORA witness Jerry Oh.
- ORA agrees with PG&E that regardless of how the Commission decides to address PG&E's proposal for 100 percent full balancing account treatment of revenues, core customers should not be allocated any over- or under-collections of noncore revenues.

Table 10-1 incorporates the recommendations above and compares ORA's and PG&E's proposed TY2015 forecasts of "Gas System Operations" expenses:

Table 10-1
Gas System Operations Expenses for TY2015
(In US Dollars)

Description (a)	ORA Recommended (b)	PG&E Proposed[3] (c)	Amount PG&E>ORA (d=c-b)	Percentage PG&E>ORA (e=d/b)
MWC CM	$17,504,900	$17,935,000	$430,100	2.5%
MWC CX	$7,310,870	$7,490,000	$179,130	2.5%
MWC JT	$18,241,252	$19,124,000	$882,748	4.8%
MWC JT	$3,088,525	$3,191,375	$102,850	3.3%
Total	$46,145,547	$47,740,375	$1,594,828	3.5%

Table 10-2 incorporates the recommendations above and compares ORA's and PG&E's proposed 2013-2015 forecasts of "Gas System Operations" capital expenditures:

[3] Table 10-1, PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-5; and PG&E Workpapers, Chapter 10, p. WP 10-1.

Table 10-2

Gas System Operations Capital Expenditures for 2013-2015
(In US Dollars)

Description	ORA Recommended			PG&E Proposed[4]		
	2013[7]	2014	2015	2013	2014	2015
MWC 26[1]	$0	$0	$6,069,219	$7,003,624	$0	$8,560,000
MWC 26[2]	$0	$100,000	$1,338,896	$2,781,376	$100,000	$1,617,840
MWC 73A[3]	$0	$0	$2,302,560	$0	$0	$10,897,000
MWC 73A[4]	$651,082	$8,371,110	$2,758,005	$0	$8,371,110	$7,051,620
MWC 73A[5]	$0	$8,348,414	$2,665,000	$40,395,293	$8,348,414	$42,463,592
MWC 73[6]				$3,654,086	$11,200,000	$8,900,000
Total	$651,082	$16,819,524	$15,133,680	$53,849,379	$28,019,524	$79,490,226

1 New Business

2 Meter Sets – Power Plant

3 NOP Reductions

4 Vintage Pipe Replacement Betterment

5 New Capacity Projects

6 Line 407 (ORA Recommendation is addressed in ORA's Attrition Testimony.)

7 As shown in RO model that includes recorded 2013 capital expenditures provided in PG&E Response to ORA DR-107

III. OVERVIEW OF PG&E'S GAS SYSTEM OPERATIONS GROUP AND RELATED PG&E ORGANIZATIONS

In order to better understand the expenses and capital expenditure proposals by the Gas System Operations group, it is important to have a general understanding of the functions of the organization and how the gas flows through PG&E's transmission system. PG&E describes the Gas System Operations group (GSO) as the organization within PG&E that ensures the safe and reliable delivery of natural gas across PG&E's gas transmission and distribution network.[5] In performing this function, the GSO includes the Gas Transmission Control Center (GTCC), the Gas Distribution Control Center (GDCC), Gas System Planning (GSP), the Wholesale Marketing and Business

[4] Table 10-2, PG&E Prepared Testimony in A.13-12-012 Volume 2 (Christopher), p.10-5. Also PG&E Workpapers, Chapter 10, p. WP 10-1.

[5] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-1.

Development Department (WM&BD), and Gas Scheduling and Accounting (GS&A).[6] The GSO functions as the active manager of the gas transmission and storage system on a daily basis to ensure the continuous availability of gas to customers. [7] PG&E proposes to staff the GTCC 24 hours a day/365 days a year and asserts the GTCC is the heart of the GSO's function. Together with the GDCC and Gas Dispatch, PG&E intends the GTCC to operate the gas transmission and storage system in real time to route gas safely and reliably for customer consumption. PG&E describes its function as analogous to that of an air traffic control tower at an airport.[8] PG&E represents that the GTCC is responsible for:

1. Proactively monitoring the entire gas system to detect and respond to abnormal conditions early enough to prevent them from escalating to safety-related conditions.[9]
2. Coordinating and monitoring pipeline inspections, maintenance, and construction through a centralized clearance process.

In performing these important functions, the GTCC utilizes Supervisory Control and Data Acquisition (SCADA) technology.[10]

In line with the above-mentioned centralized clearance process, GSP staff work with clearance coordinators to schedule all maintenance and construction work that may affect gas flow, pressures, or deliveries to customers.[11] GSP staff work with GTCC to ensure that the GT&S system has adequate capacity under all exigent operating

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[6] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-1.

[7] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-5.

[8] Id., p. 10-6.

[9] Id., p. 10-5.

[10] Described by PG&E as "an array of sensors, transducers, communications equipment, software, and computer systems that relay data continuously to the gas system operators in real time. SCADA enables operators to maintain continuous visibility into the gas system to monitor pressures, flows, and related data at approximately 14,000 points and to control system flows and pressures at approximately 800 points, including storage fields, regulator stations, compressor stations, and valves. Alarms notify operators of conditions needing attention" in PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-6.

[11] PG&E's Prepared Testimony, Volume 2 (Christopher), p.10-6.

conditions on a daily and long term basis.[12] Utilizing computerized hydraulic models of PG&E's gas system, the GSP performs the planning and design function for system growth and modifications to ensure uninterrupted gas service even under high load conditions.[13]

The WM&BD Department is the group within GSO that conducts wholesale commercial activity for PG&E. This group is responsible for contracting for capacity on the backbone transmission to transport customer-owned gas, contracting for seasonal storage, and offering related services such as balancing customer pipeline accounts. as well as the parking and lending of gas.[14]

Lastly, the GS&A Department is the group within GSO that supports all wholesale customer interactions with the gas system, such as the scheduling of gas receipts and deliveries, and accounting for usage.[15] The GS&A makes use of computerized tools and processes, including the Gas Transaction System (GTS) which is described as the primary application for managing wholesale customer business.[16] As later explained in this exhibit, PG&E proposes to replace the existing GTS, which was installed in 2008.[17]

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[12] Id.

[13] PG&E Prepared Testimony, Volume 2 (Christopher), pp. 10-6 to 10-8. Computerized hydraulic modeling is performed on an ongoing basis. GSP engineers calibrate models to actual operating data to ensure accuracy.

[14] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-6.

[15] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-7.

[16] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-38. GTS is the application used by PG&E to manage customer data, contracts, exhibits, and notifications while its wholesale customers use GTS for gas nominations, scheduling, imbalance trades, and to view their scheduled volumes, load forecasts, metered usage, and to run various reports.

[17] PG&E Prepared Testimony, Volume 2 (Christopher), pp. 10-39 to 10-41. PG&E proposes the new GTS will be developed by the end of 2017 but in the meantime proposes that the existing GTS be modified in 2015 to support two new functions: a fifth nomination cycle and customer redirection of nominated gas.

According to PG&E, its gas system is designed, operated, and sized for capacity sufficient to provide uninterrupted service under specific design-day conditions.[18] PG&E states that approximately 97 percent of the gas it delivers to end-use customers comes from outside PG&E's service territory while the remaining three percent comes from gas wells within the service territory.[19] Interstate pipelines that are located upstream of PG&E's system deliver natural gas into PG&E's transmission system at interconnection points along PG&E's backbone.[20] California-produced gas is delivered directly into PG&E's transmission system from gas gathering systems at various points.[21] From PG&E's transmission system, the gas moves to retail customers on-system and to wholesale customers off-system.[22] Customers may also store gas in underground facilities connected to PG&E's transmission system.

The basic Gas Accord structure for PG&E's gas transmission and storage has been in place since the Commission adopted the structure in 1997.[23] Over the years, the Commission has repeatedly acknowledged the many benefits resulting from the Gas Accord structure.[24] The Gas Accord structure unbundled PG&E's gas transmission and storage rates from its gas distribution rates. Prior to the Gas Accord, the bundled transmission, storage, and distribution rates were set in PG&E's General Rate Cases.[25] In this GT&S rate case, PG&E proposes to maintain the basic Gas Accord structure for transmission and storage services, but proposes a transition to full balancing account treatment for revenues.[26]

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[18] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-7.

[19] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-7.

[20] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-7.

[21] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-7.

[22] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-8.

[23] D.97-08-055.

[24] For instance, see D.03-12-061, D.04-12-050, D.07-09-045, and D.11-04-031.

[25] D.97-08-055.

[26] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-18.

PG&E cites several reasons for proposing full balancing account treatment for all transmission and storage revenues. PG&E argues that "100 percent balancing account treatment for revenues will reinforce that PG&E's highest goal is the safe operation of its facilities."[27] PG&E also cites other reasons for the proposed change:

> Full balancing account treatment is consistent with long-standing regulatory policy in California to reduce or eliminate any conflict of interest between volumetric sales and increasing energy efficiency and conservation. Full balancing account treatment will make PG&E's revenue structure consistent with those of other CPUC-regulated investor-owned utilities.[28]

PG&E already receives balancing account treatment for Core customer revenues and thus is not at risk for any Core revenues.[29] On the other hand, PG&E is at-risk for 50% of noncore backbone revenues and 25% of noncore local transmission revenues.[30] Under Gas Accord V, PG&E's gas storage revenues are subject to a one-way partial balancing account. PG&E is not allowed to put an under-collection of market storage revenue requirement in future rates, but is required to put 75% of an over-collection into future rates.[31]

In sum, PG&E's proposed transition to full balancing account treatment will minimize any remaining risk associated with noncore throughput. ORA understands that regardless of the manner PG&E's proposal is addressed by the Commission, core customers will remain unaffected and not be allocated a portion of any over- or under-collections from the noncore. PG&E clarified its proposal for full balancing account treatment :

> First, PG&E would like to clarify current treatment of core revenues and our proposal for full balancing account treatment for noncore revenues in the 2015 GT&S Rate Case. Currently, PG&E's GT&S revenue requirements allocated to core customers are decoupled, and recorded and recovered

[27] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-18.

[28] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-18.

[29] PG&E Response to ORA-DR-15-Q1c.

[30] Id.

[31] PG&E Response to ORA-DR-15-Q1d.

> through various balancing accounts. PG&E's proposal in the 2015 GT&S Rate Case is to recover the GT&S revenue requirements allocated to noncore customers in the same decoupled manner as recovery of GT&S revenues allocated to core customers (beginning January 1, 2015). Under PG&E's proposal, core customers would not be allocated any overcollections or undercollections of noncore GT&S revenues. Whether there will be any allocation of undercollections or overcollections of noncore revenues to core customers if PG&E's proposal is not adopted depends on the Commission's final decision in the 2015 GT&S Rate case. If the Commission adopts our proposal, or adopts no form of noncore balancing account treatment, core customers would not be allocated over or under collections from the noncore.[32]

In addition, although cost allocation and rate design are separately presented in Chapter 17 of PG&E's Prepared Testimony, PG&E includes a proposal to transition to equalized Redwood and Baja backbone transmission rates in Chapter 10, which deals with matters pertaining to the Gas System Operations, instead of including the discussion of the proposal in Chapter 17. For this reason, this exhibit addresses the PG&E proposal on the equalization of Redwood and Baja backbone transmission rates.

IV. DISCUSSION / ANALYSIS OF GAS SYSTEM OPERATIONS EXPENSES

The following tables summarize the PG&E proposals and ORA recommendations for the MWCs within "Gas System Operations" expenses.

[32] PG&E Response to ORA-Oral18-Q1.

Table 10-1

Gas System Operations Expenses for TY2015
(In US Dollars)

Description (a)	ORA Recommended (b)	PG&E Proposed[33] (c)
MWC CM[1]	$17,504,900	$17,935,000
MWC CX[2]	$7,310,870	$7,490,000
MWC JT[3]	$18,241,252	$19,124,000
MWC JT[4]	$3,088,525	$3,191,000
Total	$46,145,547	$47,740,375

1 Gas System Operations
2 Wholesale Marketing and Business Development
3 Compressor Fuel and Power
4 Greenhouse Gas Emissions Compliance

Table 10-2
Gas System Operations Capital Expenditures for 2013-2015
(In US Dollars)

Description	ORA Recommended			PG&E Proposed[34]		
	2013[7]	2014	2015	2013	2014	2015
MWC 26[1]	$0	$0	$6,069,219	$7,003,624	$0	$8,560,000
MWC 26[2]	$0	$100,000	$1,338,896	$2,781,376	$100,000	$1,617,840
MWC 73A[3]	$0	$0	$2,302,560	$0	$0	$10,897,000
MWC 73A[4]	$651,082	$8,371,110	$2,758,005	$0	$8,371,110	$7,051,620
MWC 73A[5]	$0	$8,348,414	$2,665,000	$40,395,293	$8,348,414	$42,463,592
MWC 73[6]				$3,654,086	$11,200,000	$8,900,000
Total	$651,082	$16,819,524	$15,133,680	$53,849,379	$28,019,524	$79,490,226

1 New Business
2 Meter Sets – Power Plant
3 NOP Reductions
4 Vintage Pipe Replacement Betterment
5 New Capacity Projects
6 Line 407 (ORA Recommendation is addressed in ORA's Attrition Testimony.)
7 As shown in RO model that includes recorded 2013 capital expenditures provided in PG&E Response to ORA DR-107

A. Expenses

There are four major categories of expense that PG&E requests for inclusion in Test Year 2015 as discussed below.[35]

[33] PG&E Workpapers, Chapter 10, p. WP 10-1.

[34] Id.

1. MWC CM for Gas System Operations

MWC CM is the major work category for Gas System Operations expenses. This expense category provides for the labor, material, consulting, contract and other costs associated with the operation and maintenance of the Gas Transmission Control Center, including costs for Gas Control, Gas Control Strategy and Support, Gas System Planning, and the Gas Scheduling and Accounting departments.[36]

Table 10-3 below shows the 2011 to 2013 recorded costs for Gas Systems Operations. PG&E forecasts $17.0 million in 2013 but recorded 2013 data shows actual 2013 spending of $17.455 million.

Table 10-3
2011-2013 Recorded Data for MWC CM
(in US Dollars)

Description		2011	2012	2013
MWC	CM	$10,594,733	$14,175,807	$17,455,000

Source: Recorded 2011-2012 data from PG&E Workpapers Supporting Chapter 10, WP 10-3. Recorded 2013 data from PG&E Response to ORA9-Q1gAtch1.

This expense is mainly for the staff required in the GTCC, GS&A and Gas System Planning to operate the gas transmission and storage system, support customers in using the system, and plan for capacity and operations on a daily and longer-term basis.[37] PG&E forecasts a flat amount of $17.0 million from 2013 through 2015, increasing only by the escalation rate.[38] PG&E's 2015 forecast for MWC CM is for $17.000 million (unescalated) and $17.935 million (escalated).[39] PG&E states:[40]

(continued from previous page)
[35] Id.

[36] PG&E Workpapers, Chapter 10, p. WP 10-3.

[37] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-33.

[38] The escalation rate multiplier shown is 1.055 (interpreted to mean a 5.5% rate) which leads ORA to believe that the more appropriate expense escalation rate should be 2.97% (as shown in Table 16-9 of PG&E Testimony) for MWC CM since it is mainly labor expense.

[39] PG&E Workpapers, Chapter 10, p. WP 10-3.

[40] PG&E Workpapers, Chapter 10, p. WP 10-4.

Labor costs expected to remain flat from 2013 to 2014. 2015 Labor costs based on a headcount of 154 with a average of 75% productivity to expense and an average annual rate of $188,875. Overall 2015 headcount expected to remain consistent with 2013 and 2014 with an increase cost in 2015 due to escalation." PG&E notes that the cost forecast "Includes labor expense from Gas Control, Gas Control Strategy and Support, Gas System Planning and Gas Scheduling and Accounting. The headcount is not necessarily the total for the departments but represents the equivalent of FTE's charging to this MWC.

In Attachment 1 to PG&E's Response to ORA-DR-9-Q1g, PG&E provides the 2013 recorded expenses for the programs described in Chapters 4 through 12 of its Prepared Testimony. For Gas System Operations, the actual recorded 2013 expense is higher than PG&E's 2013 forecast by 2.7%.

ORA notes the rising trend in expenses for Gas System Operations under the MWC CM as shown in Attachment 1 of the Response at Line 58. Based on the PG&E data between the recorded years 2012 and 2013, ORA notes an increase of approximately 23 percent in this expense category as shown in Attachment 1. For the recorded years 2009 through 2013, ORA notes an annual growth rate in this expense of approximately 13 percent. In the forecast years 2013 through 2015, PG&E proposes a slower rate of increase in this expense category which shows that the forecast 2015 (escalated) is higher by less than 3 percent compared to the recorded 2013.

When asked to explain the primary reasons for the observed rising trend in the expense category MWC CM through recorded year 2013 and the apparent slowdown in expense increases post 2013, PG&E cites to the increases in labor expense as the primary reason for the rising trend in MWC CM between 2009 and 2013. PG&E states:[41]

There was a 22% increase in labor charges to meet the new Control Room Management (CRM) rules required under Code of Federal Regulation (CFR) Title 49, Transportation, Part 192 – Transportation of Natural and Other Gas by Pipeline Minimum Federal Safety Standards, Section 192.631, "Control Room Management." The first phase of the new CRM rules went into effect in 2011 and the second in 2012. Control room Operators and Operating Specialists were hired for CRM plan development and the associated training requirement. There has also been an increase in clearance coordinators and planners since 2009 to support the system improvements and visibility. Last

[41] PG&E Response to ORA-DR-53-Q1a.

> has been the addition of Gas Control Strategy and Support (GCS&S) starting in 2012 and into 2013. GCS&S personnel are charged with expanding, upgrading, and supporting Supervisory Control and Data Acquisition (SCADA) and related control room applications.

PG&E uses the average annual rate of $188,875 per full time equivalent to estimate labor cost expense.[42] PG&E states that the labor rates in the PG&E 2014 GRC and the labor rates in this 2015 GT&S are comparable. PG&E explains:[43]

> As a point of comparison, the labor rates used in PG&E's 2014 General Rate Case for employees performing similar distribution work under MWCs FG and GG are $181,000 for Gas Control personnel, $181,000 for Gas Control Strategy and Support personnel, and $200,325 for Gas Planning Support personnel. Labor for similar transmission work is performed by personnel in those same departments, except that the 2015 Gas Transmission and Storage (GT&S) Rate Case also includes labor performed by the Gas Scheduling and Accounting Department. The labor rates in the 2014 GRC and the labor rate used in the 2015 GT&S Rate Case are comparable.

ORA inquired whether the number of operational gas transmission facilities subject to the Gas System Operations oversight has increased in 2013 from the previous levels in 2009. PG&E confirms the increase in the number of gas transmission facilities subject to this group's oversight:[44]

> The number of SCADA Gas transmission pressure transmitter devices reporting to the control center has increased from 1,113 in 2009 to 1,816 in 2014 to date. The number of remote terminal units (RTUs) that operators control has increased from 289 in 2009 to 398 in 2014 to date. The trend is expected to continue at the same pace through 2017 due to continued valve automation programs installations and associated pressure transmitters, and additional station rebuilds and pressure transmitter installation necessary for pipeline simulation.

ORA's review indicates that the 2015 forecast amount (escalated) appears to be within a reasonable range of the 2013 recorded expense. The 2015 forecast (escalated) is only 2.7% higher than 2013 recorded expense, which is a lower rate of increase than experienced in the previous recorded years. Previous recorded years

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[42] PG&E Workpapers, Chapter 10, p. WP 10-3.

[43] PG&E Response to ORA-DR-53-Q1c.

[44] PG&E Response to ORA-DR-53-Q1g.

showed significant increases of 33.8% between 2011 & 2012 and 23.1% between 2012 & 2013.[45] In this rate case, 87% of the year 2015 requested expense amount is labor cost. In previous recorded years, the labor expense component was of a higher percentage: 96% in 2011, 86% in 2012, and 89% in 2013.

ORA also reviewed the MWC CM actual expenses during the earlier period from 1997 through 2010 as shown in a 2011 audit report performed by the Overland Consulting group for the Commission's Consumer Protection and Safety Division (now known as the Safety and Enforcement Division).[46] Schedule 3-2 of the Overland Audit Report indicates that the actual amounts spent per year for MWC CM were close to $10 million a year in the initial years 1997 through 2004 but then those expenses started to decline in 2005, reaching $6 million or less in the latter years from 2006 through 2010.[47] In the two years common to the Overland Audit Report and Attachment 1 of PG&E's Response to ORA-DR-9-Q1g (i.e., 2009 and 2010), the Overland Audit Report shows lower MWC CM recorded expenses of $5.764 million and $5.530 million in 2009 and 2010, respectively while Attachment 1 of PG&E's Response shows much higher MWC CM recorded expenses of $10.530 million and $9.965 million in 2009 and 2010, respectively. The Overland Audit Report states that MWC CM Operations includes the costs of PG&E's Gas Systems Operations Department.[48] Table 3-8 of the Overland Audit Report shows the 2009 budget for MWC CM Operations was at $9.997 million but the Overland Audit Report showed only $5.764 million in actual 2009 expense. This discrepancy is indicative of one of the Overland Audit Report's findings of consistent underspending on actual transmission O&M that has negative implications for gas pipeline safety.[49]

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[45] PG&E Workpapers, Chapter 10, pp. WP 10-1 to WP 10-4 for details of the calculations.

[46] Focused Audit of the Pacific Gas & Electric Gas Transmission Pipeline Safety-Related Expenditures For the Period 1996 to 2010 ("Overland Audit Report"), submitted to the California Public Utilities Commission Consumer Protection and Safety Division by Overland Consulting, dated December 30, 2011, available as Exhibit CPSD-168 in I.12-01-007.

[47] Schedule 3-2, Overland Audit Report.

[48] Id.

[49] Audit Report, p.1-1.

The Gas System Operations is the group within PG&E that is at the frontline of gas pipeline safety. Therefore, PG&E should make use of the budget resources it deems necessary to perform its functions. As the active manager of the gas transmission and storage system on a daily basis, the Gas System Operations should use its budget resources to ensure both gas pipeline safety and reliability rather than just maintaining the continuous availability of gas to customers.

Based on the foregoing, ORA recommends the adoption of ORA's 2015 forecast which is based on PG&E's 2015 forecast amount for MWC CM in the amount of $17.000 million (unescalated), an amount deemed necessary and reasonable to perform the GSO's functions, and to provide for a downward adjustment of ($430,100) to PG&E's proposed 2015 test year escalated amount for the Gas System Operations expense to the extent that the escalation rate is excessive as noted herein.

2. MWC CX for Wholesale Marketing and Business Development Department

MWC CX provides for labor, materials, consulting, contracts and other costs associated with the operations of the Wholesale Marketing and Business Development Department, including the costs for the Product Management, Customer Service, Sales and Market Relations groups.[50] PG&E's recorded expenses for 2011 through 2013 for MWC CX are provided in Table 10-4 below.

[50] PG&E Workpapers, Chapter 10, pp. WP 10-5.

Table 10-4

2011-2013 Recorded Data for MWC CX
(in US Dollars)

Description	2011	2012	2013
MWC CX	$6,432,960	$7,026,061	$7,141,000

Source: 2011-2012 data from PG&E Workpapers, Chapter 10, p. WP 10-5. Recorded 2013 data from PG&E Response to ORA9-Q1gAtch1.

PG&E describes this expense as mainly for staff to market various pipeline and storage services to customers.[51] The costs associated with the operations of the Wholesale Marketing and Business Development Department (WM&BD) include the cost for Product Management, Customer Service, Sales and Market Relations.[52] PG&E's 2015 forecast for MWC CX is $7.490 million (escalated) and $7.100 million (unescalated). The escalation multiplier is 1.055.[53]

Labor expense is 80 percent of the MWC CX forecast 2015 expense. This labor expense is based on a headcount of 40 full time equivalents with an annual average cost of $142,500.[54]

ORA's review indicates that the forecasted increase would result in an expense amount that is within a reasonable range of the average historic recorded spending from 2011 through 2013 which is $6,866,674. PG&E's 2013 forecast is at $7.100 million while the 2013 recorded is just slightly above the forecast, at $7.141 million. PG&E's 2014 and 2015 forecasts are likewise at $7.100 million (unescalated). The 2014 forecast (unescalated) is roughly 0.6% higher than the 2013 recorded expense. ORA therefore recommends adoption of the ORA's 2015 forecast amount of $7.310 million (escalated) which is based on PG&E's proposed 2015 forecast test year amount of $7.100 million (unescalated), an amount deemed necessary and reasonable to perform the WM&BD's functions, and to provide for a downward adjustment of ($179,130) to

[51] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-33.

[52] PG&E Workpapers, Chapter 10, p. WP 10-5.

[53] PG&E Workpapers, Chapter 10, p. WP 10-6.

[54] PG&E Workpapers, Chapter 10, p. WP 10-5.

PG&E's proposed 2015 test year amount of $7.490 million (escalated) to the extent that the escalation rate is deemed excessive as discussed herein..[55]

3. MWC JT – for Compressor Fuel and Power

The MWC JT program forecasts the electric power expense to operate the electric-powered gas compressors on the backbone transmission system and at the McDonald Island storage facility. PG&E's recorded expenses for 2011 through 2013 for MWC JT are provided in Table 10-5 below.

Table 10-5
2011-2013 Recorded Data for MWC JT
(in US Dollars)

Description	2011	2012	2013
MWC JT	$4,440,000	$15,014,000	$17,696,000

Source: 2011-2012 data from PG&E Workpapers, Chapter 10, p. WP 10-7. Recorded 2013 data from Response to ORA-DR-9-Q1gAtch1.

PG&E represents that its 2015 forecast of $19.124 million is based on historic recorded costs.[56] The forecast for MWC JT is comprised of two major electric power expense items: One is for the natural gas compressor station fuel and power costs for McDonald Island and the other is for electricity powered compressors in the system.

Regarding the first expense item, PG&E states in WP 10-9:

> There are plans to remove four natural gas driven compressors at McDonald Island, which increases the likelihood of running the two existing electric compressors. The resulting electric costs will be comparable to the amount incurred during the year 2008 prior to the addition of four natural gas compressors. The dollar amount of $4.0 million from 2008 is used as the basis and escalated 3% annually to determine the future dollars.[57]

[55] PG&E Workpapers, Chapter 10, p. WP 10-6.

[56] PG&E Workpapers, Chapter 10, p .WP 10-9.

[57] PG&E Workpapers, Chapter 10, p. WP 10-9.

PG&E's 3% straight escalation from 2008 through 2015 results in the amount of $4.919 million. ORA uses the US inflation rate for the period, which is not a straight 3% annual rate, and arrives at the amount of $4.513 million for the first expense item.[58]

Regarding the second expense item, PG&E states in Testimony on p.10-31 that the sharp increase in electric power expense for system compressors in 2012 is attributable to two new electric gas compressors installed at Delevan Compressor Station and to significantly increased flows on the Redwood Path from the new interconnect with Ruby Pipeline, which became operational in July 2011.[59] Further, PG&E states "the projected utilization of the Redwood transmission path will remain fairly high, consistent with levels in year 2012. Hence, the electric costs for running the electric transmission compressors at Delevan and Bethany will remain similar to 2012."[60] In addition, PG&E notes that "Gas Control may be increasing gas balancing requirements in the future, resulting in higher storage injection frequencies."[61]

Similar to the first expense item, PG&E escalates the 2013 recorded amount of $12.975 million by 3% yearly. The resulting PG&E escalated amount should be slightly lower than the amount shown by PG&E for its 2015 forecast in the amount of $14.205

[58] US inflation rates varied from year to year, and went from negative to positive during the period: The published rates were -0.4% in 2009, 1.6% in 2010, 3.2% in 2011, 2.1% in 2012, and 1.5% in 2013, while the 2.1% forecast for 2014 is also used for 2015. Inflation rates are calculated from Consumer Price Index Data from 1913 to 2014. Consumer Price Index (CPI-U) data is provided by the U.S. Department of Labor Bureau of Labor Statistics. The CPI data was last updated by the government on July 22, 2014 and covers up to June 2014.

[59] See p.10-31 of PG&E Testimony stating that "the electric units at Delevan replaced aging gas-powered units. When they were designed for installation in 2009, the electric units were projected to have lower operating costs than gas units of comparable horsepower due to the higher price of gas at that time. Also, there were cost advantages related to the close proximity of the new Colusa electric generating station, which is the source of the units' power. The electric units also provide environmental benefits, since they have no emissions."

[60] PG&E Workpapers, Chapter 10, p. WP 10-9.

[61] Id.

million.[62] ORA uses the US inflation rate to escalate the 2013 recorded amount, which results in the amount of $13.729 million for 2015 for the second expense item.

Based on the foregoing adjustments to the escalation rate, ORA recommends adoption of its 2015 forecast expense for MWC JT in the amount of $18.241 million, which means a downward adjustment of ($882,748) to PG&E's 2015 expense forecast for MWC JT. After the adjustment, the MWC JT for 2015 should provide PG&E with approximately $18.241 million in budget expense amount.[63]

4. MWC JT – for Greenhouse Gas Emissions Costs

The MWC JT program provides for greenhouse gas (GHG) compliance instruments (allowances, expressed in metric tons of carbon dioxide equivalent or "MTCO2e") for gas compressors on the backbone transmission system and at storage facilities, and for any other gas transmission and storage equipment that may incur an obligation to procure compliance instruments under AB 32 regulations.[64] The GHG compliance instrument obligation is pursuant to AB 32.[65]

Table 10-7 in PG&E's Testimony shows that the 2015 forecast for Greenhouse Gas Compliance Instruments is $3,191,000. PG&E's WP 10-1 at Line 4 shows the 2015 GHG cost forecast to be in the amount of $3,191,375. Footnote 1 in WP 10-1 states that the forecast for GHG costs in 2013 and 2014 is $3.3 million and $3.6 million, respectively. However, the recorded 2013 data from PG&E's Response to ORA-DR-9-Q1g shows zero amount. This recorded 2013 data is reflected in Table 10-6 below. In

[62] The straight escalation of 3% per year results in $14.178 million in 2015.

[63] PG&E Workpapers, Chapter 10, p. WP 10-9.

[64] PG&E Workpapers, Chapter 10, p. WP 10-10. AB 32 is codified at California Health and Safety Code § 38500 et seq.

[65] PG&E Workpapers, Chapter 10, p. WP 10-10. According to the California Air Resources Board (ARB), AB 32 requires California to reduce its GHG emissions to 1990 levels by 2020 — a reduction of approximately 15 percent below emissions expected under a "business as usual" scenario. Pursuant to AB 32, ARB must adopt regulations to achieve the maximum technologically feasible and cost-effective GHG emission reductions. The full implementation of AB 32 will help mitigate risks associated with climate change, while improving energy efficiency, expanding the use of renewable energy resources, cleaner transportation, and reducing waste. See http://www.arb.ca.gov.

addition, PG&E's footnote 1 refers to the workpapers supporting Chapter 8. In WP 8-41, PG&E states that "The 2014 GHG forecast of $3,600K was inadvertently not included in the presentation of historical costs (see detailed Expense cost sheet line 900). In 2015 and beyond, these costs (approximately $3,200K annually) were remapped to the costs detailed in Chapter 10 (Gas System Operations)." In expense cost sheet line 900, an amount of zero is shown for the year 2015. But in WP 8-41, the total expenses for the year 2015 is shown as $6,346, 000.

When asked to explain the reasons for the difference between the amount of zero for the year 2015 in the detailed expense cost sheet line 900 and the amount of $6,346,000 for 2015 as shown in WP 8-41 and to explain what costs are included in the forecast amount of $6,346,000 , PG&E clarified:

> In the 2015 Gas Transmission and Storage Rate Case, the 2013 forecast for Green House Gas (GHG) costs were included in (Maintenance Activity Type) MAT Code JTH, Permits and Fees, which falls under Chapter 8, Gas Transmission System and Operations and Maintenance. Accordingly, 2013 GHG costs of $3.3 million were included in MAT code JTH. However, for 2014, the GHG cost forecast of $3.6 million was inadvertently excluded and not reflected in either Chapter 8 or Chapter 10.
>
> In 2015, GHG costs were forecast as part of Gas System Operations costs in Chapter 10. The support for the calculation is included in workpapers supporting Chapter 10, on pages WP 10-10 through WP 10-11. As explained in the workpapers supporting Chapter 8, on page WP 8-41, the $6.4 million forecast for Major Work Category JT (of which MAT code JTH is part) relates to permits and fees. These costs include McDonald Island reclamation fees, gas lease fees, Department of Transportation fees and lease payments. The forecast for 2015 GHG fees is not part of the above-stated $6.4 million.[66]

ORA also asked PG&E to verify that there is no double counting of the GHG emissions allowance. PG&E confirms:

> No, the amount shown in WP 8-41 for 2015 expenses does not include the same $3,191,000 forecast for GHG costs shown in WP 10-1 and Table 10-7 for the year 2015. As stated in response to part (a) above, PG&E's forecast of 2015 GHG fees is in Chapter 10, and not in Chapter 8.[67]

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[66] PG&E Response to ORA-DR-44-Q1a.

[67] PG&E Response to ORA-DR-44-Q1b.

PG&E's 2015 forecast for MWC JT GHG emissions is in the amount of $3.025 million (unescalated) and $3.191 million (escalated).[68] PG&E states that the cost projection was based on forecasted MTCO2e emissions for the six compressor stations authorized by D.13-03-017 for GHG compliance instrument cost recovery.[69] The amount was 272,116 MTCO2e.[70] According to PG&E, it identified an average price for 2015 compliance instruments of $12.10/MTCO2e.[71] PG&E later reduced this initial estimate by approximately $250,000 due to an observed downward trend in compliance instrument prices.[72]

Table 10-6
2011-2013 Recorded Data for MWC JT
(in US Dollars)

Description	2011	2012	2013
MWC JT	$0	$0	$0

Source: 2011-2012 data from PG&E Workpapers Supporting Chapter 10, WP 10-7. Recorded 2013 data from Response to ORA-DR-9-Q1gAtch1.

On pages 10-32 through 10-33 of PG&E's Testimony, PG&E requests recovery of all incurred GHG compliance obligations attributable to its GT&S facilities. PG&E states:[73]

> PG&E was authorized by Decision 13-03-017 to recover the costs of GHG compliance instruments for the six compressor stations for which it anticipated

[68] PG&E Workpapers, Chapter 10, p. WP 10-11. PG&E uses an escalation multiplier of 1.055. An escalation rate based on the general US inflation rate for 2015 would be more appropriate. ORA uses the rate of 1.9 percent.

[69] D.13-13-017 also authorized balancing account treatment for compliance costs from the six compressors.

[70] PG&E Response to ORA-DR-21-Q4b. PG&E explains that the unit abbreviation used for the emissions threshold, mtCO2e, stands for "metric tons of carbon dioxide equivalent." Carbon dioxide is the most abundant GHG. However, there are many gases that qualify as GHGs. The California Air Resources Board (CARB) and virtually all other organizations dealing in GHGs use mtCO2e to convert the GHG warming effect of these gases to a common unit—a carbon dioxide equivalent. MtCO2e is the unit of measure for CARB GHG compliance instruments.

[71] PG&E Workpapers, Chapter 10, p. WP 10-10.

[72] PG&E Workpapers, Chapter 10, p. WP 10-10.

[73] PG&E Prepared Testimony, Volume 2 (Christopher), pp. 10-32 to 10-33.

incurring compliance costs in Application 12-06-010. However, PG&E owns other gas transmission and storage facilities that have the potential to exceed the annual emissions threshold of 25,000 $mtCO_2e$ that triggers costs associated with the obligation to obtain and surrender compliance instruments. Because these other facilities were not specified in PG&E's Application 12-06-010, PG&E cannot recover compliance costs for them if they trigger the GHG compliance obligation. In particular, PG&E now forecasts that Tionesta Compressor Station, which was not included in Application 12-06-010, will incur compliance costs because increased flows from Ruby Pipeline are driving high utilization levels for that facility. Other gas transmission and storage facilities may also incur an obligation in the future if their greenhouse gas emissions exceed the annual emissions threshold set by ARB…Therefore, PG&E is requesting recovery of all incurred GHG compliance obligation costs attributable to any of its gas transmission and storage facilities.

ORA asked PG&E to identify the "other facilities," in addition to the Tionesta Compressor Station, that were not specified in A.12-06-010. PG&E responded:[74]

The other facility in addition to Tionesta Compressor Station that was not specified in Application (A.).12-06-010 (the application that resulted in D. 13-03-017), but has the potential to exceed the current annual emissions threshold is McDonald Island. At this time, no other gas facility in the 2015 Gas Transmission and Storage (GT&S) Rate Case is likely to exceed the 25,000 metric tons of carbon dioxide equivalent (mtCO2e) annual threshold for the duration of this rate case period. Note that a "facility" for the purposes of complying with the California Air Resources Board's (CARB) requirements for greenhouse gas emissions means all equipment within the fence line of the facility collectively, not the individual pieces of equipment. Thus, all of the Tionesta Compressor Station is a facility, as is all of McDonald Island. Note that other gas facilities, including PG&E's other storage facilities Pleasant Creek and Los Medanos, may also be subject to GHG compliance obligations if CARB reduces the compliance threshold. PG&E has no indication at this time that CARB is contemplating such a change.

ORA's review reveals the following:

1. PG&E's 2015 forecast is based on the forecasted MTCO2e emissions for the six compressor stations authorized in D.13-03-017 and an identified average price for 2015 of $12.10/MTCO2e.

2. Review of GHG prices in the forward market as well as the California Air Resources Board 2014 Annual Auction Reserve Price notice confirms the direction of PG&E's 2015 forecast .[75]

[74] PG&E Response to ORA-DR-37 Q2b.

[75] The CARB issued a notice on December 2, 2013 (and updated on June 24, 2014) available on its website at http://www.arb.ca.gov.

3. There may be additional PG&E GHG compliance obligations in addition to the six compressors identified in D.13-03-017. Before cost recovery of GHG compliance obligations for additional GT&S facilities is authorized, PG&E should be required to demonstrate, in a manner that permits Commission validation, that the Tionesta Compressor Station and other gas facilities would in fact exceed the current emissions threshold, as PG&E has said it expects to occur, and thus, would be subject to GHG compliance obligations similar to those authorized in D.13-03-017.

4. The PG&E 2015 forecast should be adjusted for the 2.1% escalation rate that was used by ORA.

Based on the foregoing, ORA recommends adoption of ORA's 2015 forecast in the amount of $3.088 million (escalated) which is based on PG&E's 2015 expense forecast for MWC JT for GHG Emissions cost in the amount of $3.025 million (unescalated), and should be subject to an adjustment of ($102,850) for escalation.

B. Capital Expenditures

PG&E's proposed capital expenditures for 2015 for Gas System Operations are presented in PG&E's Testimony in Table 10-4 related to New Business and in Table 10-5 related to Capacity Products[76] Both tables are summarized in PG&E's Workpapers supporting Chapter 10, Gas System Operations.[77]

1. MWC 26 New Business

MWC 26 provides capital expenditures for New Business which covers the costs of extending new gas transmission facilities from the existing gas transmission system to provide service to new loads.[78] PG&E states that the work includes "procuring land rights and easements, facility design (estimating, mapping, and engineering), materials,

[76] PG&E Prepared Testimony, Volume 2 (Christopher), pp. 10-22 to 10-24.

[77] PG&E Workpapers, Chapter 10, p. WP 10-1.

[78] PG&E Prepared Testimony, Volume 2 (Christopher), pp. 10-22 to10-23 and PG&E Workpapers, Chapter 10, p. WP 10-15.

permitting, construction, and initial operation of the pipeline system."[79] Four main cost drivers identified by PG&E for New Business capital expenditures include (1) location of the new customer(s) in relation to PG&E's system; (2) projected gas demand or load; (3) duty cycle, time of year, and hours of the day that the new customer will operate; and (4) existing planned investments to serve customer load growth.[80] PG&E's 2015 capital expenditure forecast for MWC 26 (New Business) is $8.560 million.[81]

There are two types of projects under New Business: small and large projects.[82] ORA's review indicates the following:

1. PG&E uses average historic spending on small projects of $4 Million for 2011-2014 (the 4-year average is $4.866 million with the PG&E 2013 forecast of $7.003 million used in calculating the average). ORA uses the recorded 2013 values rather than the forecast for MWC 26 of $1.309 million in calculating the average.[83]

2. PG&E's forecast for the cost of large projects is based on two residential development projects: A Stockton project with a $3 million estimate and a Madera project with a $9 million estimate. Together, the Stockton and Madera combined projects result in $12 million for large projects. PG&E estimated a 2/3 likelihood to the large projects, which results in $8 million capital expenditures, which were split to $4 million in 2015 and $4 million in 2017.[84]

3. In a data response, PG&E indicated that the Stockton developer has made no progress since 2012 and PG&E views this project as unlikely to proceed.[85]

4. Although a bonafide load request for an initial Madera project was submitted, this project appears uncertain considering that PG&E had once given the

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[79] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-22.

[80] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-22.

[81] Id.

[82] Id., p. 10-23.

[83] PG&E Response to ORA-DR-9 Q4a.

[84] PG&E Workpapers, Chapter 10, p. WP 10-17.

[85] PG&E Response to ORA-DR-53 Q5d.

Stockton project a 2/3 likelihood but then later said the project was unlikely.[86] Absent additional information, ORA assigns a 50/50 likelihood to this project.

5. PG&E expects Tesoro Viejo to begin development in 2016-2017, but has not yet received a bonafide load request for calculation from the developer.[87] PG&E estimates that if Tesoro Viejo proceeds, it would require approximately two to three miles of new 8-inch pipe at approximately $5 million per mile. PG&E states that given the increase in unit cost for 8-inch pipe since the original estimate was included in this rate case, the total cost forecast for new business capacity in the Madera area would be $20-25 million, $9-14 million more than PG&E is requesting.[88] Without any showing regarding the increase in pipe unit costs, ORA considers this as an unsubstantiated PG&E assertion.[89] ORA therefore uses the original $3M/mile estimated unit cost provided by PG&E to calculate the cost estimate.

6. Based on the foregoing, without a bonafide load request, ORA views Tesoro Viejo as uncertain.[90] ORA assigns a less than 50/50 chance for this project to begin development in 2016-2017.

7. ORA's calculation uses the cumulative capital escalation rate shown in the PG&E RO model to determine the escalated amount which is 1.066 in 2015 while PG&E rounded off the cumulative escalation to 1.070 in 2015, or a difference of 0.004.

8. Table 10-7 shows the recorded capital expenditures for New Business from 2008 through 2013. PG&E forecast for 2013 was $7.003 million but the recorded 2013 showed only $1.309 million in actual spending.

Table 10-7
2008-2013 Recorded Data for MWC 26
(in US Dollars)

Description	2008	2009	2010	2011	2012	2013
MWC 26	$657,000	$440,000	$1,583,000	$3,917,876	$14,645,056	$1,309,613

Source: 2008-2010 recorded data from Schedule 4-1, Focused Audit of Pacific Gas & Electric, "Gas Transmission Pipeline Safety-Related Expenditures" submitted to California Public Utilities Commission by Overland Consulting, dated December 30, 2011. The 2011-2012 recorded data are from PG&E's

[86] Id.

[87] PG&E Response to ORA-DR-53 Q5.

[88] PG&E Response to ORA-DR-53-Q5.

[89] PG&E Workpapers, Chapter 10, p. WP 10-17 indicate that 3.0 miles 12" steel at $3 million per mile for large residential development in Madera was used for PG&E's estimate. Any claim regarding increased pipe unit costs that is different from PG&E's filing should be supported by PG&E, otherwise, it is considered an unsupported assertion.

[90] PG&E Response to ORA –DR-53 Q6 Atch1 listed the Tesoro Viejo/Gateway as unlikely.

Workpapers Supporting Chapter 10, p.10-15. The recorded 2013 data is from PG&E's Response to ORA_009-Q04a and Q04b.

Based on the foregoing, ORA recommends a forecast 2015 capital expenditure amount of $6.069 million for MWC 26. Given PG&E's 2015 forecast of $8.560 million, ORA's recommended adjustment for PG&E's 2015 capital expenditures forecast for MWC 26 is ($2.49 million). Any Post-Test year capital expenditures required will be addressed in ORA's chapter on Post-test Year ratemaking.

2. MWC 26 Meter Sets - Power Plant

The MWC 26 program Meter Sets – Power Plant consists of the installation of meter stations and other supporting facilities for 3rd party customers that PG&E is obligated to service.[91] PG&E states that new connections typically involve customer payments.[92] By tariff rules, PG&E recover from the customer the costs requested for recovery here.[93] PG&E's 2013 forecast amount is $2.781 million, .the 2014 forecast amount is $100,000, and the 2015 forecast amount is $1.618 million. Table 10-8 shows the recorded data in the years 2008 through 2013 for capital expenditures for Meter Sets.

ORA's review of WP 10-20 reveals that PG&E included forecasted cost estimates for "unknown projects" in its calculations. These estimates are unsupported.[94] ORA's review shows that PG&E included a significant amount of unknown project costs relative to known project costs. For example, there were 3 previously unknown projects listed as "new and possible" as of June 2014 for a forecasted amount of $926,000 as compared to 17 known "possible or likely" projects with a forecasted amount of $2.138 million. PG&E's inclusion of cost estimates for "unknown projects" have no support in PG&E's workpapers. ORA recalculated the

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[91] PG&E Workpapers, Chapter 10, p. WP 10-18.

[92] PG&E Workpapers, Chapter 10, p. WP 10-18.

[93] PG&E Workpapers, Chapter 10, p. WP 10-18.

[94] Line 54 at PG&E Workpapers, Chapter 10, p. WP 10-20.

forecast cost estimates for unknown projects based on the percentage of possible projects relative to known projects.[95]

ORA recommends a forecast 2015 capital expenditure amount of $1.338 million for MWC 26 Meter Sets – Power Plant. PG&E's 2015 capital expenditure forecast of $1.618 should be adjusted downward by ($278,944).[96] Any post-test year capital expenditures will be addressed in ORA's chapter on Post-test Year ratemaking.

Table 10-8
2008-2013 Recorded Data for MWC 26
(in Thousands of US Dollars)

Description	2008	2009	2010	2011	2012	2013
MWC	na	na	na	$8.214	$5.889	$0.0

Source: 2008-2010 recorded data not available. The 2011 and 2012 recorded data are from PG&E's Workpapers, Chapter 10, p. WP 10-18. The recorded data for 2013 not yet available (pending ORA DR 107).

3. MWC 73A NOP Reductions

MWC 73A capital expenditures are for projects to implement the Normal Operating Pressure (NOP)[97] reductions involving the installation of pipe to support programmatic reductions of the normal operating pressures of the transmission system so that the pressure of a line is maintained below the Maximum Allowable Operating Pressure (MAOP) at all times.[98] These projects are in line with the implementation of PG&E's new NOP policy, which is described as a risk-reduction strategy.[99] According to PG&E, the new NOP policy "creates an extra margin of safety" and is said to be

[95] There were 3 possible projects listed as of June 2014 relative to the 17 known projects.

[96] Line 2 in Table 10-4, PG&E Prepared Testimony, Volume 2 (Christopher), p.10-22.

[97] PG&E defines "Normal operating pressure of the transmission system" as the set point of the primary regulator or pressure limiting station serving the system. On the backbone transmission system, the normal operating pressure (NOP) is sometimes determined by the discharge pressure of a compressor station. PG&E Response to ORA-DR-4 Q1b.

[98] PG&E Workpapers, Chapter 10, p. WP 10-21. PG&E explains the phrase "Below MAOP at all times" to mean that all primary regulators, overpressure protection devices, and compressor discharges are set to keep system pressure at less than MAOP (maximum allowable operating pressure) at all times. PG&E Response to ORA DR-4 Q1b.

[99] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-12.

consistent with SB 705 and its mandate to engage in best practices in the industry for safety.[100] PG&E states that reducing NOP and installing overpressure protection devices to ensure that no line will exceed MAOP for the entire PG&E system will require an estimated $75.6 million capacity project investment to maintain pipeline capacity at present levels.[101] The original PG&E request for NOP reduction projects in 2015 was $10,897,000.[102] The corrected PG&E forecast for 2015 is $10.337 million (escalated).[103] The capital expenditure request will be used to install pipe to support programmatic reductions of the normal operating pressures of the transmission system so that pipeline pressures are kept below MAOP at all times, while maintaining levels of pipeline capacity to support customer service at the appropriate design standard.[104] There are fourteen capacity reinforcement projects identified in PG&E's workpaper in relation to the NOP reduction programmatic implementation in the rate case period 2015-2017.[105]

ORA's review reveals the following:

1. It is PG&E's intent to reduce the NOP and OPP below the MAOP in every transmission system it operates.[106] OPP and NOP reduction policies are currently already being implemented by PG&E.[107]

2. The NOP policy resulted from an operational decision within the Gas System Operations Department.[108] There is no formal authorizing document for this new policy.[109] Implementation of the NOP policy began September 4, 2012.[110]

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[100] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-12.

[101] The original forecast for this program was $80.4 million for 2015-2017. PG&E Prepared Testimony, pp. 10-12 and 10-27. This was later revised to $75.6 million as shown in PG&E Response to ORA-DR-Oral6 Q1.

[102] PG&E Workpapers, Chapter 10, p. WP 10-21.

[103] PG&E Response to ORA-DR-Oral6-Q1.

[104] PG&E Workpapers, Chapter 10, p. WP 10-21.

[105] PG&E Workpapers, Chapter 10, p. WP 10-23.

[106] PG&E Response to ORA-DR-76-Q5.

[107] PG&E Response to ORA-DR-55-Q2.

[108] PG&E Response to ORA-DR-4-Q1d.

3. PG&E explains that the "extra margin of safety" is created by setting the normal operating pressure (NOP) of a pipeline systems' regulators sufficiently below the maximum allowable operating pressure (MAOP) of the pipe contained in that system, such that high alarms and high-high alarms will be triggered well before pressure reaches MAOP.[111] Setting lower pressures relative to MAOP are safer by definition. If the NOP is set very close to or at the MAOP (a practice designed for maximum pipeline utilization), there may be a comparatively small or even no interval between a high or high-high alarm and MAOP.[112]

4. PG&E states that the extra margin of safety can be quantified and measured by the percentage or absolute difference between the NOP and the MAOP.[113] PG&E has not quantified the extra margin of safety. However, since PG&E began to programmatically reduce its normal operating pressures, the number of incidents in which pressure exceeded MAOP declined from 774 in 2011 to 31 in 2013. PG&E believes that this policy is a best-practice to minimize overpressure events.[114]

5. According to PG&E, it identified 14 specific systems where it intends to reduce the NOP rather than the MAOP. PG&E says it will require additional capacity to be built to support design day conditions.[115]

6. The extra margin of safety is viewed with respect to each hydraulically independent system whose regulator set points and/or compressor discharge points have been reduced. PG&E states it has 219 hydraulically independent local transmission systems. PG&E conducted high level hydraulic analysis for each of the 14 local transmission systems in order to forecast the costs of this program. The cost difference between uprating an entire local transmission system or replacing the entire pipe in a local transmission system has not been analyzed.[116]

(continued from previous page)
[109] PG&E Response to ORA-DR-44-Q1d.

[110] PG&E Response to ORA-DR-4-Q1d. In PG&E Response to ORA-DR-23-Q1, PG&E identified the local transmission line segments whose Normal Operating Pressure (NOP) has been reduced. In addition, the NOP of PG&E's backbone system has been reduced. This includes Lines 300A, 300B, 400, 401, and the Bay Area Loop (Lines 107, 114, 131, and 303).

[111] PG&E Response to ORA-DR-4 Q2a.

[112] PG&E Response to ORA-DR-4 Q2a.

[113] PG&E Response to ORA-DR-4 Q2a.

[114] PG&E Response to ORA-DR-4 Q2a.

[115] PG&E Response to ORA-DR-44 Q4.

[116] PG&E Response to ORA-DR-55 Q3.

7. PG&E states that the key criterion used in the hydraulic modelling that resulted in the projects identified for priority is that on the design day at peak demand, the system must be able to maintain a minimum pressure in order to ensure uninterrupted service.[117] As PG&E explains, that design day is either an Abnormal Peak Day (APD) which applies to systems whose predominant load is core, and which is temperature dependent, or a Cold Winter Day (CWD) which applies to systems whose predominant load is noncore, which is not temperature dependent. The minimum low pressure for a given local transmission system depends on the downstream systems (distribution or other).[118]

8. PG&E states the proposed projects were selected to identify a cost estimate to achieve the required design day capacity. According to PG&E, uprating and replacing are not mutually exclusive, and a project can involve both as well as other engineering solutions. The solutions for the 14 NOP projects generally involve paralleling existing pipe with additional pipe. The uprate and replace concepts, which are alternatives to paralleling, were put forward in response to a hypothetical question ORA asked in ORA-DR-4 Q2b. ORA asked PG&E to explain whether there were other alternatives to create the "extra margin of safety" that were considered by PG&E but were not adopted, and if so, to please explain why these other alternatives were considered but not adopted by PG&E. PG&E states that question does not relate to actual projects.[119]

9. PG&E explains that the systems proposed for capacity improvements under the normal operating pressure reduction (NOP) program are near-constrained or already constrained. Reducing the set point of their regulators will reduce their capacity to a point that, without additional pipe, there would be a significant risk of uncontrolled customer outages on the design day.[120]

10. PG&E argues that if the capacity expansion projects are not undertaken, one of two outcomes is possible. In one case, PG&E must elect to retain current set point pressure, which results in PG&E foregoing an increased margin of safety. Second, if PG&E implements the reduction without the increase in capacity, design day

[117] PG&E Response to ORA-DR-76 Q4.

[118] PG&E Response to ORA-DR-76-Q4

[119] PG&E Response to ORA-DR-55-Q3.

[120] PG&E Response to ORA-DR-76-Q4.

standards will not be met, putting customer at risk for loss of supply at peak load conditions.[121]

11. PG&E states that the NOP/OPP policy is an extension of PG&E's Gas Safety Plan, which is required by SB 705, Public Utilities Code §961(a) (1).[122] PG&E filed its first Gas Safety Plan on June 29, 2012, which the Commission approved in Decision 12-12-009. A revised Gas Safety Plan was filed on June 28, 2013 where the revised filing describes PG&E's analysis of its transmission system "to determine the feasibility of reducing normal operating pressure on systems identified by the PSEP Pipeline Modernization Program Decision Tree by as much as 20.0 pounds per square inch gauge (psig) below the Maximum Operating Pressure (MOP), and reducing over-pressure protection by as much as 5.0 psig below MOP, to create a margin of safety against overpressure events."[123]

12. PG&E claims it has standards in development with respect to the NOP policy but it has not yet shared those with the SED nor does it have any scheduled meetings with SED on the subject at this time.[124] PG&E explains it has not discussed OPP policy with SED but has discussed NOP reduction policy.[125]

13. Six out of the fourteen NOP reduction projects identified in WP 10-23 have been cancelled as of June 15, 2014.[126] Of the eight projects remaining on the list, only one project is shown for completion in the year 2015, four projects for completion in

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[121] PG&E Workpapers, Chapter 10, p. WP 10-21.

[122] PG&E Response to ORA-DR-76-Q2 defines "Regulator Set Point" as the normal operating pressure (NOP) and "OP Set Point" represents the pressure at which overpressure protection (OP or OPP) takes control. In same Response, PG&E defines the "Maximum Allowable Operating Pressure for a segment of pipe, as prescribed by 49 CFR 192.105, 192.611 and 192.619." PG&E states that "Maximum Operating Pressure (MOP) applies to an entire hydraulically independent pressure system rather than solely to a segment of pipe. It is determined by the MAOP of the weakest pipe segment in a given system." Further, PG&E states it "is in the process of eliminating the MOP definition and replacing it with a new definition, High Operating Pressure Limit (HOPL), which is defined as the operating pressure limit at a measurement point that if exceeded indicates that operating pressure is exceeding the MAOP of the associated subsystem or any other imposed pressure limitation. The limit takes into account subsystem characteristics such as elevation, temperature, etc. Use of the MOP definition is expected to be phased out beginning in July 2014."

[123] PG&E Response to ORA-DR-4-Q2c.

[124] PG&E Response to ORA-DR-53-Q3.

[125] PG&E Response to ORA-DR-53-Q3.

[126] PG&E Response to ORA-DR-60-Q2d.

2016, and three projects are for completion in 2017. All eight projects are still in the hydraulic engineering and planning stage.[127] PG&E indicated that the estimated time to implement a typical capacity project from hydraulic analysis to in-service date ranges from 18 to 60 months.[128] PG&E indicated that a timeline has not been developed for the NOP projects.[129]

14. PG&E has acknowledged that the estimates for these NOP projects were high-level, front-end estimates, and must be further studied to identify the specific engineering solution.[130] The implementation of NOP reductions to date have not required capacity expansions.[131] PG&E states that each NOP project will have its own timeline that is not necessarily tied to the others.[132] PG&E's plan is to complete these NOP projects by the end of 2017.[133]

15. Despite the apparent importance of implementing the NOP reduction projects, PG&E explains that the primary factor that could potentially affect the likelihood of PG&E's implementation of the proposed NOP reduction projects is emergent work that rises higher in the priority queue in PG&E's risk-ranking system.[134] According to PG&E, this could delay design, engineering, planning, permitting, construction, or all of the foregoing. The unavailability of qualified resources to perform the work or of materials could also delay the work.[135]

Based on the limited scope of the program at this time, ORA does not oppose the continued implementation of the NOP/OPP policies on PG&E's gas transmission system so long as they do not interfere with PG&E's ability to perform the highest priority work first. Since there is only one project identified for completion in 2015, four projects in 2016, and three projects in 2017, ORA's recommendation adjusts the timing

[127] PG&E Response to ORA-DR-60-Q2d.

[128] PG&E Response to ORA-DR-60-Q2d.

[129] PG&E Response to ORA-DR-21-Q2j.

[130] PG&E Response to ORA-DR-21-Q2j.

[131] PG&E Response to ORA-DR-21-Q2j.

[132] PG&E Response to ORA-DR-21-Q2j.

[133] PG&E Response to ORA-DR-21-Q2j.

[134] PG&E Response to ORA-DR-55-Q3.

[135] PG&E Response to ORA-DR-55-Q3.

of the projects costs to address the currently forecasted dates of project completion. ORA recommends the adoption of forecast 2015 capital expenditures for NOP reduction in the amount of $2.302 million (escalated). Therefore, PG&E's 2015 forecast of capital expenditures should be adjusted downward by removing the amount of ($8.034) million. Any post-test year capital expenditures required will be addressed in ORA's chapter on Post-test Year ratemaking.

4. MWC 73A for Vintage Pipe Replacement Betterment

Table 10-9 below shows the recorded data for Vintage Pipe Replacement Betterment. PG&E recorded data in 2011 and 2012 showed zero spending. PG&E forecasted zero spending for 2013 as well but the recorded 2013 data showed $651,000 actual spending.

Table 10-9
2008-2013 Recorded Data for MWC 73A
(in US Dollars)

Description	2008	2009	2010	2011	2012	2013
MWC	na	na	na	$0.00	$0.00	$651,000

Source: 2008-2010 recorded data not available. The 2011 and 2012 recorded data are from PG&E's WP 10-18. The recorded data for 2013 is from PG&E Response to ORA-DR-60-Q1a. PG&E 2013 forecast is zero.

The MWC designation for Vintage Pipe Replacement Betterment is the same as the MWC for NOP Reduction projects and new capacity projects - MWC 73A.

According to PG&E, Vintage Pipe Replacement Betterment ("Betterment") projects typically involve increasing the pipe diameter or length of the planned replacement to reduce the risk of having to do a more costly incremental project in the future in areas where such incremental projects are expected in the near future based on growth projections.[136] For Betterment projects, the economic justification is based on the expectation that upsizing is less costly over the longer term compared to

[136] PG&E Workpapers, Chapter 10, p. WP 10-24. The glossary of the American Gas Association defines the term betterment as: "A substantial enlargement or improvement of existing structures, facilities, or equipment by the replacement or improvement of parts, which has the effect of extending the useful life of the property, increasing its capacity, lowering its operating cost, or otherwise adding to the worth through the benefit it can yield."

undertaking a second excavation in the near to medium term.[137] To forecast Betterment costs for the rate case period, PG&E derived a Betterment rate by using the ratio of the forecast 2013-2014 PSEP pipeline replacement program costs and the forecast 2013-2014 Betterment costs.[138] PG&E's 2015 forecast for MWC 73A Vintage Pipe Replacement Betterment is $7.052 million (escalated).[139]

ORA's review reveals the following:

1. The projects identified under the Vintage Pipe Replacement program as described in Chapter 4 and the projects identified under the Vintage Pipe Replacement Betterment described in Chapter 10 are related in terms of how the forecast capital expenditures for Betterment were derived. The Vintage Pipe Replacement Betterment program forecast for 2015-2017 described in PG&E's Chapter 10 Testimony is based on a percentage of overall forecasted expenditure for the Vintage Pipe Replacement Program (VPRP) in Chapter 4A, Transmission Pipe Integrity and Emergency Response Programs.[140]

2. The PG&E Betterment rate of 5.6% was derived using the PG&E forecast numbers as of April 16, 2013 for average Betterment spending in 2013 and 2014 and the Pipeline Replacement Program. The forecast spending was later reduced by PG&E, but PG&E still retained the Betterment rate at 5.6%.

3. ORA's calculation of the Betterment rate of 2.2% uses the recorded 2013 Betterment capital expenditures and the forecast 2014 Betterment number after ORA obtained PG&E's response about the expected completion of Betterment projects forecast in 2014.[141]

4. At this time, PG&E has not identified any specific Betterment projects.[142]

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[137] PG&E Workpapers, Chapter 10, p. WP 10-24.

[138] PG&E Workpapers, Chapter 10, p. WP 10-24 to WP 10-25.

[139] PG&E Workpapers, Chapter 10, p. WP 10-24.

[140] PG&E Response to ORA-DR-78-Q2a.

[141] PG&E Response to ORA-DR-60-Q1b.

[142] PG&E Response to ORA-DR-78-Q2a.

5. No specific studies have been done showing that upsizing is less costly over the long term than not upsizing.[143]

6. PG&E has made clear that the Betterment costs identified in Chapter 10 will be incurred only if Betterment is performed on Vintage Pipe Replacement Program (VPRP) segments.[144] Further, Betterment will be performed only if hydraulic engineering shows that it will relieve a flow constraint more effectively and/or economically than two separate projects, one for the VPRP replacement, and one to relieve the hydraulic constraint identified in the modeling process.[145]

Based on ORA's use of a 2.2% Betterment rate rather than PG&E's proposed 5.6% rate, ORA recommends the adoption of its 2015 forecast Betterment capital expenditures for MWC 73A in the amount of $2.758 million, which means a downward adjustment of ($4.293 million) to PG&E's 2015 forecast of $7.052 million. Any post-test year capital expenditures required will be addressed in ORA's Exhibit 18 on Post-Test Year ratemaking.

5. MWC 73A for New Capacity Projects

Table 10-10 below shows the recorded data for capital expenditures for new capacity in the years 2008 through 2013. PG&E forecast for 2013 was for $40.395 million but recorded 2013 showed that only $25.812 million was actually spent.

Table **10-10**

2008-2013 Recorded Data for MWC 73A
(in US Dollars)

Description	2008	2009	2010	2011	2012	2013
MWC	$91,869,000	$44,954,000	$54,619,000	$15,036,873	$30,012,642	$25,812,782

Source: The 2008-2010 recorded data from Schedule 4-1, Focused Audit of Pacific Gas & Electric, "Gas Transmission Pipeline Safety-Related Expenditures" submitted to California Public Utilities Commission by Overland Consulting, dated December 30, 2011. The 2011 and 2012 recorded data are from PG&E's WP 10-26. The recorded data for 2013 is from PG&E Response to ORA_009-Q04b and PG&E Gas Safety Reports for 2013 spending. PG&E forecast 2013 amount is $40.395 million.

[143] PG&E Response to ORA-DR-78-Q2c.

[144] PG&E Response to ORA-DR-21-Q2f.

[145] PG&E Response to ORA-DR-21-Q2f.

PG&E describes the capacity projects in this rate case as required to maintain capacity at accepted customer service design standards while incorporating increased loads due to growth. Without these projects, PG&E states that if projected growth occurs as forecast, the local transmission system will be at risk for uncontrolled outages (loss of supply) at design day temperatures due to insufficient capacity.[146] PG&E estimates the cost per mile of installed pipe based on the most recent, most analogous project in terms of pipe diameter, pipeline length and the character of the installation route.[147] PG&E states that detailed estimates based on vendor quotes are not yet available at the time of preparation of these cost estimates since no detailed engineering has been undertaken for these projects.[148] The projects were identified by PG&E based on the results of its hydraulic modeling.[149] In PG&E's WP 10-28, PG&E identified 18 capacity projects based on forecasts of local growth that show supply loss risk without reinforcement.[150] For 2015, PG&E forecasts $42.463 million for new capacity in MWC 73A.

ORA's review reveals the following:

1. When asked about the size of the "increased load" due to growth and whether it could quantify the capacity of the pipe being planned to be added, PG&E states that the size of the increased load (gas usage) is particular to each local transmission system and that PG&E does not have a quantification of the capacity of the added pipe because capacity is not a static quantity.[151] PG&E explains that the capacity is a dynamic non-linear function of upstream and downstream pressure and that PG&E's metric for capacity adequacy is based on whether hydraulic modeling shows that all loads can be served on the design day.[152]

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[146] PG&E Workpapers, Chapter 10, p. WP 10-26.

[147] PG&E Workpapers, Chapter 10, p. WP 10-26.

[148] PG&E Workpapers, Chapter 10, p. WP 10-26 and PG&E Response to ORA-DR-44-Q4b.

[149] PG&E Response to ORA-DR-44-Q4a.

[150] PG&E Workpapers, Chapter 10, p. WP 10-28.

[151] PG&E Response to ORA-DR-44-Q4d and Q4f.

[152] PG&E Response to ORA-DR-44-Q4f.

2. PG&E states that the projects shown on lines 1, 2, and 5 of WP 10-28 are cancelled as of June 15, 2014.[153]

3. PG&E states that the projects shown on lines 3 and 4 of WP 10-28 are undergoing preliminary engineering with estimated completion in 2017 as of June 15, 2014.[154]

4. PG&E states that the projects shown on lines 6, 7, and 8 of WP 10-28 are undergoing hydraulic engineering and planning with estimated completion in 2015 for the line 6 project and 2017 for projects on lines 7 and 8.[155]

5. PG&E states that project shown on line 9 of WP 10-28 is in preliminary project engineering with estimated completion in 2015.[156]

6. PG&E states that projects shown on lines 10 through 15 of WP 10-28 are undergoing hydraulic engineering and planning with estimated completion ranging from 2016-2018 or post 2018 or unknown.[157]

7. No indication of project status was provided by PG&E for projects shown on lines 16, 17, and 18 of WP 10-28.[158] ORA therefore assumes these projects are cancelled.

Based on the foregoing, ORA recommends adoption of the 2015 forecast of capital expenditures for new capacity in MWC 73A in the amount of $2.665 million, which means a downward adjustment of ($39.798) million to PG&E's 2015 forecast of $42.464 million. Any post-test year capital expenditures required will be addressed in ORA's chapter on Post-Test Year ratemaking.

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[153] PG&E Response to ORA-DR-44-Q4c.

[154] PG&E Response to ORA-DR-44-Q4c.

[155] PG&E Response to ORA-DR-44-Q4c.

[156] PG&E Response to ORA-DR-44-Q4c.

[157] PG&E Response to ORA-DR-44-Q4c.

[158] PG&E Response to ORA-DR-44-Q4c.

6. MWC 73 for Line 407

Table 10-11 shows recorded data for capital expenditures for Line 407 for 2008 through 2013. PG&E forecast $3.654 million in 2013 but recorded 2013 shows only $2.366 million of actual spending.

Table **10-11**
2008-2013 Recorded Data for MWC 73
(in Thousands of US Dollars)

Description	2008	2009	2010	2011	2012	2013
MWC	$26	$6,730	$6,129,	$3,441	($3,494)	$2,366

Source: Recorded 2008 through 2013 data are from PG&E Response to ORA_044-Q03b. The recorded 2011 and 2012 data match those from PG&E Workpapers shown in WP 10-29. PG&E forecast for 2013 is in the amount of $3.654 million and shown in PG&E WP 10-29.

PG&E describes Line 407 as a 25.5 mile, 30-inch transmission pipeline that extends from Line 406 and Line 172A in the town of Yolo east to Line 123 in Roseville. In addition, the project includes a new 10-inch Distribution Feeder Main (DFM) that extends 2.4 miles from Line 407 out to the Sacramento Metropolitan Air Park which will be part of the local transmission system.[159] According to PG&E, Line 407 had previously been included in the 2008 and 2011 GT&S rate cases for cost recovery as an Adder project. PG&E explains:[160]

> An Adder project is a capital project that PG&E agrees to put in rates on January 1 following the project's operable date. During the time period covering these earlier cases, the construction of L407 was deferred due to lower than forecasted growth and the abrupt halt in housing construction during the economic crisis of 2008-2009. Therefore, PG&E has not received cost recovery for Line 407.

When asked whether PG&E will consider, and possibly institute another deferral, as it had done in the past if the forecast demand growth in the Sacramento Valley Local Transmission (SVLT) system area does not materialize, PG&E responded that it has no plans to defer the Line 407 project because the constraints on the SVLT system have

[159] PG&E Workpapers, Chapter 10, p. WP 10-29.

[160] PG&E Response to ORA-DR-9-Q4e.

already manifested.[161] PG&E's response refers to the cold conditions[162] in December 2013 that caused constraints in the SVLT where PG&E had to resort to vigorous manual intervention and extensive region-wide noncore customer curtailments.[163]

When asked whether PG&E proposes the Line 407 project as another Adder project similar to how the project received Adder treatment in the 2008 and 2011 GT&S rate case settlements, PG&E clarified the proposed cost recovery for Line 407 in this 2015 GT&S rate case:[164]

> …L407 cost recovery should follow the traditional capital recovery timing which ties the recovery to the forecasted operable date of the project. The forecasted operable date for the project is 8/1/2017. The proposed cost recovery for L407 includes an additional provision to address the possibility of the project not becoming operable in 2017. This provision was included in light of the regulatory history of this project. PG&E proposed that rates be adjusted in 2018 to remove the 2017 cost recovery if the project doesn't become operable in 2017. Subsequent cost recovery beyond 2017 would be addressed in future GT&S rate cases. (See Chapter 18 pages 18-6 and 18-7).

Based on the foregoing possibility that the project may finally be implemented and become operable in 2017 or later, ORA's recommendation on Line 407 will be addressed in ORA's Attrition Testimony.

V. DISCUSSION/ANALYSIS OF OTHER PG&E PROPOSALS PRESENTED IN GAS SYSTEM OPERATIONS

A. General Overview and Summary

PG&E makes a number of other proposals in Chapter 10 of its Prepared Testimony where the justifications/rationale of the projects are included in the chapter

[161] PG&E Response to ORA-DR-37-Q3d.

[162] PG&E Response to ORA-DR-76-Q4a states that design day is either an Abnormal Peak Day (APD), which applies to systems whose predominant load is core, which is highly temperature-dependent, or a Cold Winter Day (CWD), which applies to systems whose predominant load in noncore, which is not as temperature-dependent.

[163] See PG&E Testimony, Chapter 10, pp.10-28 to 10-29 and PG&E Response to ORA-DR-37-Q3c.

[164] PG&E Response to ORA-DR-9-Q4e and ORA-DR-37-Q3e.

but where the relevant project costs are presented elsewhere in other chapters of PG&E's Prepared Testimony.[165] ORA presents those projects below as proposed by PG&E.

1. PG&E proposes reallocating 130 MMcf/d of injection capacity and 200 MMcf/d of withdrawal capacity of storage assets for load balancing and modifying core storage injection and withdrawal rights. PG&E proposes to increase the storage withdrawal and injection capacity dedicated to daily balancing from the current 75 thousand decatherms per day (MDth/d) each for withdrawal and injection to 200 MDth/d for withdrawal and 130 MDth/d for injection to accommodate peak hour needs.[166] According to PG&E, the additional storage injection and withdrawal capacity will be reallocated to load balancing from existing facilities currently allocated to the noncore market storage program and the additional capacity will be for all months of the year.[167]

2. PG&E proposes adoption of a fifth nomination cycle at 9:00 PM Pacific Time for on-system storage and Citygate transactions.[168]

3. PG&E proposes the adoption of adjustments and ongoing improvements to the Core Load Forecasting Model (CLFM).
    - PG&E proposes a change to the CLFM which it believes will yield greater Determined Usage accuracy. CLFM will be modified to use an average of 24 hourly temperature forecasts, one for each hour of the gas day rather than a simple average of the forecast daily high and low.[169]

4. PG&E proposes the adoption of changes to its Gas Transaction System (GTS).
    - PG&E proposes to replace the GTS with a new system.[170] Without replacement, PG&E explains it would need additional expense dollars in this rate case and the next one to support GTS until 2020.[171]
    - The relevant Project Costs are shown in Chapter 11.

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[165] For Information Technology related proposals, the project costs presented in Chapter 11 of PG&E's Testimony. These project costs are addressed by ORA's witness for Chapter 11.

[166] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-5.

[167] PG&E Responses to ORA-DR-63-Q1e and Q1f.

[168] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-40.

[169] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-43.

[170] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-3.

[171] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-39.

5. PG&E proposes to replace the Gas Transmission Control Center's ("GTCC") Supervisory Control and Data Acquisition ("SCADA") system and to upgrade other information technology related to the GTCC.[172] PG&E proposes to:
   - Upgrade and expand its SCADA system for the gas transmission and storage system. PG&E explains that the existing SCADA system is reaching the end of its technological lifespan and must be replaced by current technology to achieve best practice operation as required by SB 705.[173]
   - Proposes to leverage its SCADA system to improve leak rupture detection for the transmission system and use Artificial Intelligence technology.[174]
   - Use advanced control room applications[175]
   - Use collaborative technology with field personnel[176]
   - Use artificial intelligence system[177]

6. PG&E proposes the adoption of changes to the storage asset mix for operational reasons as described below:
   - Remove 4 compressor units at McDonald Island and allow lease of 4 older units to expire. Those units will be removed from operation in July 2014; but three newer units will be retained.[178]
   - Reduce well deliverability at McDonald Island.
   - The relevant Project Costs are shown in Chapter 6.[179]

7. PG&E proposes to increase Core winter withdrawal rights in December and January and Decrease in Feb and March.[180]

8. PG&E proposes to eliminate the annual inventory threshold that determines the method by which injection and withdrawal rights for Core Procurement Groups (CTAs and CGS) are determined.[181]

9. PG&E proposes other system values that impact cost allocation or rate design – such as the BTU value shown in Table 10-13 and the Shrinkage shown in Table 10-14.[182]

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[172] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-34.

[173] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-34.

[174] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-36.

[175] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-36.

[176] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-37.

[177] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-38.

[178] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-46.

[179] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-45.

[180] PG&E Prepared Testimony, Volume 2 (Christopher), pp.10-50 to10-51

[181] PG&E Prepared Testimony, Volume 2 (Christopher), pp. 10-51 to 10-52.

B. DISCUSSION/ANALYSIS OF OTHER PG&E PROPOSALS

ORA opposes PG&E's proposal to reallocate storage assets and modify core storage injection and withdrawal rights. ORA does not oppose the implementation of the remaining PG&E proposals, as discussed below. However, ORA witnesses address and review the project costs of these PG&E proposals in the other chapters where PG&E proposed recovery of the project costs.

1. Reallocation of Storage Assets and Modification of Core Storage Injection and Withdrawal Rights

PG&E claims that reallocation of storage assets and modification of core storage injection and withdrawal rights is driven by the need to manage fluctuating intraday demands.[183] If not granted, PG&E states it may need to move from monthly balancing to daily balancing to manage these fluctuations.[184] Ultimately, PG&E claims, backbone capacity contracts may have to be based on peak hourly flows rather than daily average flows.[185] According to PG&E, existing intraday demands have required PG&E to use a greater amount of storage injections and withdrawals to balance the system than is now allocated to the balancing function.[186]

ORA opposes the PG&E request for reallocation of additional storage capacity for load balancing because PG&E has failed to demonstrate that the need for additional load balancing is warranted at this time nor that the alleged "operational risk and

(continued from previous page)
[182] PG&E Prepared Testimony, Volume 2 (Christopher), pp. 10-52 to p.10-53.

[183] PG&E Response to ORA-DR-63-Q1a.

[184] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-48.

[185] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-48.

[186] PG&E Workpapers, Chapter 10, pp. WP 10-54 to WP 10-79.

elevating risk of increased OFOs and Emergency Flow Orders (EFO)"[187] is attributable to or caused by core ratepayers to warrant the additional cost burden (i.e., increased backbone transmission rates) to core ratepayers.

PG&E's proposal would increase end-use rates by $0.005/dth or 0.03% compared to the existing allocation of storage for load balancing, backbone transmission rates by $0.023/Dth or 5.2% based on equalized rates, and decrease core firm gas storage reservation rates by $0.014/Dth/mo or by 7.4%,[188] Under a traditional cost-based rate design, backbone transmission rates would also increase by a similar $0.023/Dth or by 6.0% since the rate increase is relative to a lower backbone rate based on the traditional cost-based differential. These rate impacts are based on PG&E's proposed revenue requirements. The rate impacts will be lower if the PG&E revenue requirements are lower. PG&E explains why the impact on gas storage rates is to decrease or to move opposite the movement of the backbone transmission and end-use rates. PG&E states two reasons for this effect on storage rates:

1) Under PG&E's proposal, some capacities currently allocated to Market Storage would be reallocated to Pipeline Balancing. This would decrease the share of capacity, and therefore storage units, that go to Market Storage and increase the share of capacities and storage units that go to Pipeline Balancing. This decrease in the share of storage units for Market Storage decreases the rates for Market Storage and likewise increases the backbone rates because that is where the Pipeline Balancing costs are recovered.

2) The second reason is that the total number of storage units increases when providing the additional capacity to Pipeline Balancing. While the number of Core's storage units remained the same, the total number of storage units increased. The total storage units would increase because the length of time during the year that balancing would have the capacities reserved is greater than the time during the year that Market Storage had the capacities reserved. This effectively reduced core's overall percentage of the whole even though their number of storage units did not change.[1] Consequently, Market Storage's share of revenue requirements is reduced. When this is combined with

[187] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-49.

[188] PG&E Response to ORA-DR-63-Q2.

reduction in the capacity share, core storage rates would be reduced.[189]

2. Fifth Nomination Cycle

PG&E proposes an additional gas scheduling cycle late in the gas day. PG&E states that the fifth nomination cycle "will allow shippers to change their gas supplies as each day's dispatch of electric generation becomes clearer throughout the day".[190] PG&E refers to this proposal as a "fifth nomination" or "late cycle." When asked about this proposal, PG&E explained:

> The Gas Transaction System (GTS) is currently designed so that the fourth cycle (Intraday 2) is the last processed cycle of the day. To add a fifth cycle, PG&E would not only have to change the fourth cycle software logic, but also develop new logic for entering nominations and processing the fifth cycle. A fifth cycle nomination would differ from the standard four cycles in that it would not allow gas to be moved from PG&E's system to other pipelines or from other lines onto PG&E. The fifth cycle nominations will be limited to PG&E Citygate and to or from storage (both Independent Storage Providers (ISP) and PG&E). Since the fifth cycle will not involve scheduling gas with interconnecting pipelines, PG&E will not include a fifth-cycle scheduling module to confirm fifth-cycle volumes; instead, fifth-cycle volumes would be declared final after running the confirmation process...The cost forecast for this project is provided in the 2015 Gas Transmission and Storage (GT&S) Rate Case testimony for Chapter 11 on page 11-25 and in workpapers supporting testimony on pages WP 11-69 through WP 11-83.[191]

PG&E has not identified any disadvantages to PG&E customers as a result of this proposal other than the small amount of increased costs. Customer participation in the fifth nomination cycle is voluntary.[192]

PG&E has identified electric generators as a customer segment that would benefit from the fifth cycle proposal.[193] This additional nomination cycle will give

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[189] PG&E Response to ORA-Oral16-Q1.

[190] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-40.

[191] PG&E Response to ORA-DR-24-Q5a.

[192] PG&E Response to ORA-DR-24-Q5e.

[193] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-40.

electric generators the ability to better respond to dispatch orders from the California Independent System Operator (CAISO) and could reduce their risk of Operational Flow Order (OFO) non-compliance charges.[194] Other customers who experience variable load, unpredicted load changes, or supply changes during the gas day may also benefit from this proposal.[195]

PG&E also clarified that it is not proposing to exempt any customer group from bearing the cost of the Fifth Nomination Cycle, since it would be impractical and not cost-effective to exempt any subset of customers from cost recovery of the related costs, given the relatively small magnitude of the costs and the spread of IT costs as part of common costs among the Unbundled Cost Categories (UCCs) used for ratemaking.[196] These costs account for approximately four one-hundredths of a percent (0.04%) of PG&E's total 2015 GT&S Rate Case proposed revenue requirement and would account for perhaps one one-hundredth (0.01%) of total average rates.

ORA does not oppose an additional gas scheduling cycle late in the gas day, called the fifth nomination cycle, since the proposed change is expected to provide benefits to shippers, and costs are minimal.

3. Changing the Core Load Forecast Model

On pages 10-42 through 10-44 of Chapter 10, PG&E describes its proposed adjustments to Core Load Forecasting. PG&E states that "In Gas Accord V, PG&E agreed to retune" the Core Load Forecast Model (CLFM), and to explore whether smart meter data could be used to improve forecast accuracy." According to PG&E, it had completed the CLFM re-tuning in 2011. PG&E described the results of its investigation on the use of data from gas smart meters. In addition, PG&E proposes to "pursue continuous improvements in Determined Usage accuracy by conducting ongoing analysis on the CLFM and its inputs.

[194] PG&E Response to ORA-DR-24-Q5f.

[195] Id.

[196] PG&E Response to ORA-DR-24-Q5g.

When asked to provide the specific reference to the Gas Accord V settlement agreement where "PG&E agreed to re-tune the CLFM and explore whether smart meter data could be used to improve", PG&E responds by citing the reference:

> Paragraph 11.2 of the Gas Accord V Settlement Agreement refers to the CTA (Core Transport Agent) Settlement Agreement. Within the CTA Settlement Agreement, PG&E agreed to re-tune the Core Load Forecast Model (CLFM) and explore whether SmartMeter™ data could be used to improve forecast accuracy as stated in paragraphs C.1.a and C.1.b. of the Settlement Agreement, quoted below:
>
> **C) PG&E System Enhancements**
> 1) PG&E agrees to implement the following system enhancements within the Gas Accord V period but no later than the date noted below:
> a) PG&E agrees to re-tune the Core Load Forecast model by October 1, 2011;
>
> b) PG&E proposes to evaluate the effectiveness of re-tuning the Core Load Forecast Model twelve months following its initial use, and in collaboration with the CTAs, determine whether a rebuild will be needed while incorporating the SmartMeter usage data by April 1, 2013; [197]

PG&E indicates that the costs of modifying the CLFM are included in the costs of ongoing system operations and maintenance and enhancements described in the 2015 Gas Transmission and Storage (GT&S) rate case testimony for Chapter 11 on pages 11-37 to 11-38 and in workpapers supporting Chapter 11 on page WP 11-6, Line 1.[198] According to PG&E, included in the $5.4 million forecast for baseline maintenance and enhancement costs on WP 11-6, line 1, is the CLFM system forecast of $100,000 in 2015. This forecast of $100,000 is based on engineering estimates developed to support the work described in detail in the 2015 GT&S testimony for Chapter 10 on pages on pages 10-42 through 10-44.[199]

PG&E describes the benefits to the PG&E Core customers of the proposed adjustments to the CLFM as follows:[200]

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[197] PG&E Response to ORA-DR-24-Q7a.

[198] PG&E Response to ORA-DR-24-Q7b.

[199] Id.

[200] PG&E Response to ORA-DR-4-Q7c.

> Basing the CLFM's average temperature methodology on a 24-hour profile will increase the accuracy of the forecast of core customer daily gas usage (Determined Usage). This, in turn, may help Core Procurement Groups (PG&E Core Gas Supply and CTAs) minimize operating imbalances, per Gas Schedule Gas Balancing Service for Intrastate Transportation Customers (G-BAL**1**). Minimizing operating imbalances may lead to a lower volume of gas commodity transactions undertaken to rectify imbalances, which may support lower gas procurement costs. It may also reduce the size and volatility of the monthly Operating Imbalance Carryover, improving the ability to plan procurement activities.

ORA does not oppose the proposed change to the Core Load Forecast Model since the proposal is expected to provide benefits in terms of increasing the accuracy of core customer's determined usage that could lead to minimizing operating imbalances, and potentially result in lower gas procurement costs.

4. Gas Transaction System (GTS) Replacement

PG&E represents that until it begins the Gas Transaction System ("GTS") project in 2015 and analyzes potential technology alternatives, it cannot determine the precise technology it will pursue to replace the GTS.[201] PG&E plans to issue a Request for Proposal (RFP) to understand the options to replace the current GTS.[202] Based on the proposals that PG&E receives, a strategy for replacement and an underlying technology will be selected. As PG&E states in testimony, "the new GTS will be developed by 2017. Meanwhile, the existing GTS will be modified in 2015 to support two new functions; a fifth nomination cycle and a customer redirection of nominated gas."[203]

PG&E explains that the Customer Nomination Redirect Project would provide customers, during the day of flow and after an OFO has been called, an opportunity to redirect gas they had already brought onto PG&E's system to a storage account or to

[201] PG&E Response to ORA-DR-24-Q3.

[202] Current GTS was deployed in 2008 as stated in PG&E's Prepared Testimony, Volume 2 (Caffery), p.11-26.

[203] PG&E Prepared Testimony, Volume 2 (Christopher), p. 10-40

another on-system end-user.[204] This would help customers manage their gas supplies on the day of flow and potentially avoid OFO non-compliance charges, which would be a customer benefit.

According to PG&E, it has not identified any groups that would be disadvantaged by PG&E's redirect proposal.[205] PG&E cites an example of who could possibly benefit: an electric generator who has scheduled gas to a particular power plant. If, during the gas day, the CAISO orders the power plant to reduce or stop generation, then, without the ability to redirect the gas away from that premise, the unburned gas would still be scheduled to that facility. If an OFO were in effect, that scheduled but unburned gas would be used in the calculation of an OFO non-compliance charge. This problem can exist for any non-core customer with variable or unpredicted day-of-flow load changes.[206]

ORA does not oppose the PG&E proposal to replace its GTS because PG&E's existing system is based on an outdated technology, and while the precise GTS replacement technology is still under study, PG&E proposes to modify the existing GTS to support the two new functions described here.

5. SCADA Upgrade, Leak Rupture Detection Implementation, Advance Control Room Applications, Collaborative Technology With Field Personnel, and Artificial Intelligence

PG&E proposes to upgrade and expand its SCADA system.[207] Aside from the SCADA project, PG&E has a total of four (4) additional projects that involve new and upgraded information technology for Control Center Operations, namely: (1) Leak

[204] PG&E Response to ORA-DR-24-Q6.

[205] PG&E Response to ORA-DR-24-Q6.

[206] Id.

[207] PG&E Prepared Testimony, Volume 2 (Christopher), pp.10-34 to 10-41.

Rupture Detection (2) Advance Control Room Applications; (3) Collaborative Technology With Field Personnel; and (4) Artificial Intelligence.[208]

PG&E's consultant found that the existing SCADA system is adequate for current needs but is not an industry leading solution and contains a number of deficiencies that complicate operations and increase maintenance.[209] The consultant also recommended that the transmission SCADA system be separate from the distribution SCADA as explained in PG&E's testimony.[210]

ORA inquired whether PG&E has undertaken a formal study on the cost and benefits of the above projects. PG&E responded that it has not performed a formal cost benefit study for these projects.[211] According to PG&E, these projects are either in the earliest stages of implementation or not yet started. These projects were identified as necessary components to implementing its Gas Transmission Control Center strategy to transform data into intelligence to operate predictively and proactively in order to identify and mitigate risks in real time. Each project goes through an intake process that involves assessing benefits versus cost. Many of the benefits of these projects are safety related and qualitative in nature due to the difficulty in quantifying the dollar value of predictive and proactive operations.[212]

In discovery, PG&E provided, as a confidential attachment, a copy of the final report referenced in Footnote 11 on p.10-34 of its testimony.[213] Section 1.1 of this report summarizes three major recommendations. The last one addressed the need to update PG&E's SCADA system. When asked to confirm whether PG&E performed the

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[208] Id.

[209] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-34.

[210] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-35.

[211] PG&E Response to ORA-DR-24-Q2d.

[212] Id.

[213] PG&E Response to ORA-DR-24-Q1a.

analysis proposed in the third recommendation and to briefly summarize the results of the PG&E analysis, PG&E responded:[214]

> In 2013, PG&E determined that to upgrade the current gas Supervisory Control and Data Acquisition (SCADA) system was not as advisable as proceeding with an overall replacement of the SCADA system. The basis for this decision was that only one of the 12 key SCADA system limitations that the Honeywell SCADA Assessment identified by could be resolved by a version upgrade, and that resolution would be less than comprehensive. In addition, the level of effort to upgrade the current SCADA system was substantial in both duration and cost.

PG&E states that it proposes to leverage its SCADA system to improve leak rupture detection for the transmission system.[215] In Footnote 15, PG&E cites to the NTSB recommendations in explaining the driver for this project. PG&E further explains that "The main tool is on-line pipeline pressure and flow simulation software from SynerGEE. The concept is to compare pressures and flows in segments of the pipeline detected by SCADA to modeled pressures and flows in near real-time."[216] In addition, PG&E states its intent to use Artificial Intelligence (AI) technology and describes the AI system and how the AI system will enable operators to respond more quickly to developing situations and be more effective in prevention and mitigation and contribute to overall system safety. PG&E also describes "advanced control room applications" and making use of "collaborative technology with field personnel."[217]

PG&E explains that these projects/programs will help address risks associated with a large leak or pipeline rupture, the loss of a significant number of customers through inadequate gas pressure, or exceeding MAOP.[218]. PG&E adds that these projects will also help address risks from equipment failures by potentially identifying

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[214] PG&E Response to ORA-DR-60-Q7.

[215] PG&E Prepared Testimony, Volume 2 (Christopher), pp.10-36 to 10-38.

[216] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-36.

[217] PG&E Prepared Testimony, Volume 2 (Christopher), pp.10-36 to 10-38.

[218] PG&E Response to ORA-DR-24-Q2e.

early indications of equipment degradation.[219] This includes the top risks presented by stable construction and manufacturing threats, external corrosion, large high pressure excursions, and mechanical damage to pipeline. Further, PG&E explains that these projects/programs will help PG&E reduce risk by enabling earlier identification of abnormal operating situations and improve Control Room tools for responding to a developing emergency event.[220] However PG&E has not calculated the impact on risk reduction for each of the aforementioned risks identified.[221]

Training for these new projects will be provided as part of system deployment and are included in the estimated costs.[222]

Based on the foregoing, ORA does not oppose the above described projects with implementation subject to the project cost recommendations in ORA's chapter on these Information Technology projects.

6. Changes to the Storage Asset Mix

PG&E proposes changes to its storage asset mix.[223] As explained, PG&E is allowing the lease for the four older gas compressor units at McDonald Island to expire and plans to remove them from operation in July 2014. The three newer units will be retained to support firm injection rights.[224] PG&E also explains that the current market for storage services does not support continued costs of maintaining high well capacity.[225] PG&E expects reduced maximum firm storage withdrawal as of January 1, 2015 to 2,010 MDth unlike those seen in Gas Accord V.[226] PG&E explains the reason for this is PG&E's reduced investment in routine well rework activities otherwise

[219] PG&E Response to ORA-DR-24-Q2e.

[220] PG&E Response to ORA-DR-24-Q2e.

[221] Id.

[222] PG&E Response to ORA-DR-24-Q2j.

[223] PG&E Prepared Testimony, Volume 2 (Christopher), pp.10-45 to 10-46.

[224] Id.

[225] Id.

[226] Id.

required to maintain the Gas Accord V capacities.[227] PG&E states that the estimated cost impact on PG&E's customers for reducing well rework is a one-time savings in 2014 of approximately $2.4 million.[228] In addition, PG&E explains that it "proposed a five percent reduction in overall storage capacities, which has no cost impact."[229] On the question of whether PG&E's core and noncore customers will be paying higher gas storage rates with the changes in total storage capacities, the answer has not been completely shown by PG&E yet. The analysis provided by PG&E in response to the latter ORA question was based on an ORA hypothetical based on maintaining the total storage capacities at the Gas Accord V adopted levels. In Response, PG&E explains that its analysis has not accounted for several considerations:

> PG&E has not accounted for the increase in revenue requirement that would be necessary to maintain the higher overall storage capacities adopted in Gas Accord V. Specifically, PG&E has not added in the additional rental compressor costs or well rework costs that it would incur to maintain this capacity. In addition, in recalculating the backbone rates, PG&E has not taken into account secondary impacts such as the impact a backbone rate change has on the backbone load factor.[230]

ORA does not oppose the proposed change in storage mix so long as the Core customers are not burdened with any incremental costs arising from or related to this proposed change in storage mix. PG&E should provide the Commission with a complete analysis regarding the impact of the change in total storage capacities to PG&E's core and noncore customer's gas storage rates.

[227] Id.

[228] PG&E Response to ORA-DR-24-Q9a.

[229] Id.

[230] PG&E Response to ORA-DR-24-Q9b.

7. Increasing Core Winter Withdrawal Rights in December and January and Decrease in Feb and March[231]

PG&E proposes to increase the Core's winter withdrawal rights in the months of December and January and to decrease them in the months of February and March.232 PG&E claims that the proposed change would reshape the Core winter firm withdrawal rights curve to better fit Core winter supply requirements, improving winter reliability by increasing withdrawal rights during the coldest part of the winter.[233] Table 10-12 of PG&E's Testimony shows the proposed increases and decreases by month in the Core Winter Firm Withdrawal Rights Curve.[234] PG&E represents that the overall storage inventory capacity allocated to CPGs will remain the same.[235] PG&E also represents that the overall ratio of injection to inventory will remain the same.[236] Finally, PG&E represents that there is a small change of the overall ratio of inventory to withdrawal rights with the proposal.[237] Based on the foregoing, ORA does not oppose this proposal.

8. Elimination Of The Annual Inventory Threshold That Determines The Methodology For Injection And Withdrawal Rights For Core Procurement Groups (CTAs And CGS)[238]

PG&E proposes to eliminate the fixed-rights method for injection and withdrawal rights for core procurement groups and use the variable method exclusively.[239] As described in Testimony, the injection and withdrawal rights for Core Procurement

[231] PG&E Prepared Testimony, Volume 2 (Christopher), pp.10-50 to p.10-51.

[232] PG&E Prepared Testimony, Volume 2 (Christopher), pp.10-50 to p.10-51.

[233] Id.

[234] Id.

[235] Id.

[236] Id.

[237] Id.

[238] PG&E Prepared Testimony, Volume 2 (Christopher), pp.10-51 to p.10-52.

[239] Id.

Groups (i.e, CTAs and CGS) that hold 1,000 MDth of Annual Inventory or less are fixed on Annual Inventory alone.[240] The injection and withdrawal rights for CPGs that hold more than 1,000 MDth are based on the Annual Inventory and the Current Inventory, or balance of gas in their storage account, which varies.

PG&E defines "Current Inventory" as the amount of gas that the core procurement group (CPG) has in storage on any given day.[241] On the other hand, PG&E defines "Annual Inventory" as the capacity, irrespective of the amount of physical gas (i.e., Current Inventory) in storage.[242]

ORA inquired whether PG&E conducted customer consultations regarding this proposal. PG&E states it did not conduct customer consultations regarding the PG&E proposal to eliminate the annual inventory threshold that determines the method by which injection and withdrawal rights for CTAs and CGS are determined.[243] According to PG&E, it has not identified any customer group that could be disadvantaged by its proposal.[244] According to PG&E, during the rebuttal for this testimony in this proceeding, PG&E can respond to any potential intervenor or customer concern in regard to this proposal.[245]

ORA does not oppose the PG&E proposal but reserves its right to comment in response to concerns raised.

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[240] Id.

[241] PG&E Response to ORA-DR-24-Q13a.

[242] Id.

[243] PG&E's Response to ORA-DR-24-Q13.

[244] PG&E's Response to ORA-DR-63-Q4.

[245] Id.

9. Other System Values That Impact Cost Allocation Or Rate Design – Such As The BTU Value Shown In Table 10-13 And The Shrinkage Shown In Table 10-14.

PG&E proposes to use the BTU conversion factors shown in Table 10-13 for rate design, among other things.[246] PG&E also proposes to use the base shrinkage rate for transmission shown in Table 10-14 of its testimony.[247] PG&E represents that the Btu conversion factors are representative of the actual heating values on the PG&E system over the last several years.[248] PG&E also states that it used the existing base shrinkage rates specified in Advice Letter 3236-G (effective November 1, 2011) for calculating proposed rates.[249] ORA does not oppose this proposal.

VI. DISCUSSION / ANALYSIS OF REDWOOD AND BAJA BACKBONE TRANSMISSION RATE EQUALIZATION

This section discusses PG&E's proposal to equalize the rates in the Redwood and Baja backbone transmission lines.[250] The PG&E proposal would result in five standard backbone rate classifications, namely: Core Redwood/Baja rate; Noncore Redwood/Baja rate; Silverado rate; Mission rate; and G-XF rate.[251] According to PG&E, its proposal will retain the current backbone service offerings and contract practices.[252] In addition, PG&E explains that Core customers will retain the preferential rate on the Redwood Path.[253]

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[246] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-52.

[247] Id.

[248] Id.

[249] Id.

[250] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-19.

[251] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-20.

[252] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-20.

[253] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-20.

PG&E's proposal on rate equalization means that core rates would have an absolute "zero" rate differential between the Redwood and Baja paths, as would noncore rates. Both paths would have exactly the same firm and as-available core and noncore rates.[254]

PG&E provides a history of the backbone rates as described below and in the chart that follows:[255]

> Throughout all Gas Accords, the core Baja rates have been higher than core Redwood rates. Noncore Baja rates were lower than noncore Redwood rates until Gas Accord IV, when noncore Baja rates became higher than noncore Redwood rates. Prior to the Gas Accord IV Settlement, the rate differentials between Baja and Redwood were calculated based on the adopted revenue requirements for each path. In the Gas Accord IV Settlement, the backbone rates were set by applying agreed upon escalators to 2007 rates and establishing a $0.025 per Dth differential between noncore Redwood and Baja rates with Baja being the higher of the two (see Gas Accord IV Settlement section 8.1 and 8.2). The core and noncore Redwood and Baja differentials in the Gas Accord V Settlement are based purely on the differentials agreed to by the parties and adopted by the CPUC.
>
> Redwood & Baja Backbone Transmission Rates from Gas Accord I through Gas Accord V showing G-AFT at 100% contract utilization in $/Dth.

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
$0.155	$0.164	$0.169	$0.172	$0.175	$0.175	$0.192			
$0.253	$0.265	$0.267	$0.269	$0.269	$0.269	$0.300			
$0.098	$0.101	$0.098	$0.097	$0.094	$0.094	$0.108	$0.030	$0.006	$0.006
$0.155	$0.164	$0.169	$0.172	$0.175	$0.175	$0.192	$0.278	$0.308	$0.308
$0.115	$0.118	$0.119	$0.122	$0.124	$0.124	$0.129			
-$0.040	-$0.046	-$0.050	-$0.050	-$0.051	-$0.051	-$0.063	-$0.117	-$0.133	-$0.133

[254] PG&E Response to ORA-DR-15-Q5a.

[255] PG&E Response to ORA-DR-15-Q5b and Q5c.

2008	2009	2010	2011		2012	2013		2014
			Jan-Apr	May-Dec	-	Jan-Mar	Apr-Dec	
		$0.319	$0.319	$0.307	$0.313	$0.299	$0.303	$0.306
		$0.294	$0.294	$0.282	$0.283	$0.264	$0.268	$0.266
-$0.025	-$0.025	-$0.025	-$0.025	-$0.025	-$0.030	-$0.035	-$0.035	-$0.040
$0.325	$0.322	$0.319	$0.319	$0.249	$0.252	$0.247	$0.251	$0.259
		$0.155	$0.155	$0.224	$0.222	$0.212	$0.216	$0.219
-$0.167	-$0.166	-$0.164	-$0.164	-$0.025	-$0.030	-$0.035	-$0.035	-$0.040

Note: The rates shown for GA III include a Local Transmission Bill Credit Surcharge of $0.0030 per Dth.
The rates shown for GA IV and V include a Local Transmission Bill Credit Surcharge of $0.0024 per Dth.

PG&E considers its proposal to be an incremental change from the backbone rate design adopted in Gas Accord IV and Gas Accord V. In Gas Accord IV, the negotiated settlement resulted in creating a $0.025 per decatherm spread between the Noncore Redwood and Noncore Baja rates.[256]

The following table 10-12 with Errata corrections discussed in Chapter 17 summarizes the backbone transmission rates as a result of adopting PG&E's request for the Equalized Redwood and Baja Rates using PG&E's revenue requirements and throughput forecast and ORA's recommendation for the traditional cost-based rate design for Redwood and Baja using ORA's recommended revenue requirements and throughput forecast:

[256] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-20.

Table 10-12 Corrected for Errata

Traditional vs Equalized Redwood and Baja Rates for TY2015
Annual Rates SFV/MFV Rate Design
(In Dollars/Dth)

Description (a)	ORA Recommended (b)	PG&E Proposed[257] (c)	Difference In $ (d)=(c)–(b)	Difference in % (e)=(d)/(c)
Redwood Path - Core	$0.2745	$0.4599	$0.1854	40.31%
Baja Path - Core	$0.4588	$0.4599	$0.0011	0.24%
Redwood Path - Noncore	$0.3426	$0.5124	$0.1698	33.14%
Baja Path - Noncore	$0.4588	$0.5124	$0.0536	10.46%
Silverado & Mission Paths	$0.2301	$0.3234	$0.0933	28.85%

PG&E argues that equalizing Redwood and Baja rates is beneficial to ratepayers and supported for other reasons.[258] PG&E asserts that equalization of the rates in the two backbone transmission paths will benefit PG&E customers by applying downward pressure to the price of gas at the PG&E Citygate.[259] PG&E explains how the current arrangement tends to push up Citygate prices:

> The Citygate price is typically set by the marginal supply source (the combined cost of gas and transportation service on the non-preferred path.) Since upstream supplies on the Redwood Path are generally cheaper at present, the Baja Path is the non-preferred path and the marginal supply source. Absent rate equalization, the Baja transportation rate would be higher than the Redwood rate for both Core and Noncore shippers, because Baja's revenue requirement is higher than Redwood's. This would tend to push Citygate prices upward relative to what they would otherwise be with equalized rates.[260]

The PG&E arguments quoted above are not supported by any PG&E analysis showing how equalizing Baja and Redwood rates would lead to downward pressure to the price of gas at the PG&E Citygate. At this point, without any analysis, PG&E has

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[257] Table 17-E in PG&E Prepared Testimony, Volume 2 (Niemi), p.17AtchA-5. See also Table 17-1 on p. 17-5.

[258] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-21.

[259] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-21.

[260] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-21.

failed to substantiate the rationale supporting its proposal to equalize the Redwood and Baja backbone transmission rates. PG&E further cites support from operational and policy reasons.[261] In addition, PG&E cites the postage stamp transmission rate design that the Commission has adopted for the SoCalGas system.[262] However, PG&E has not shown how its proposal will benefit ratepayers and result in lower PG&E Citygate prices. In fact, PG&E's proposal will result in higher backbone transmission rates to PG&E's customers compared to the traditional cost-based rate design in the Gas Accords. The following Table 10-13 compares the backbone transmission rates under PG&E's proposal to equalize and under the traditional rate design using PG&E's Proposed Revenue Requirements and throughput forecast filed in this rate case.

Table 10-13
Comparison of "Equalized Redwood and Baja Rates" and Traditional Gas Accord Rate Design for TY2015
Annual Rates SFV/MFV Rate Design
(In Dollars/Dth)

Description (a)	Traditional Rate Design[263] (b)	PG&E Proposed[264] (c)	Difference (in $/Dth (d)= (c) – (b)	Difference(in %) (e) = (d)/(b)
Redwood Path - Core	$0.3862	$0.4599	$0.0737	19.1%
Baja Path - Core	$0.6422	$0.4599	($0.1823)	(28.4%).
Redwood Path - Noncore	$0.4373	$0.5124	$0.0751	17.2%
Baja Path - Noncore	$0.6422	$0.5124	($0.1298)	.(20.2%)
Silverado & Mission Paths	$0.3234	$0.3234	$0.0	0.0%

When asked whether the proposal for equalized rates on Redwood and Baja mean a PG&E shipper can enjoy postage stamp rates on PG&E's system, that is, the shipper can deliver either from Redwood or Baja to anywhere on the PG&E system and be charged one rate, PG&E explains:

> The term "postage stamp" is not accurate for two reasons. First, Baja and Redwood Path capacity must be contracted for separately. For example, a shipper cannot contract for Baja capacity and then ship on the Redwood Path without a Redwood

[261] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-21.

[262] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-21. The SoCalGas/SDG&E gas transmission systems are economically and operationally integrated, as authorized by Commission Decision in D.06-04-033.

[263] As shown in PG&E's Backbone Transmission Rate Model in the 2015 GT&S.

[264] PG&E Prepared Testimony, Volume 2 (Niemi), p.17-5.

contract. Second, PG&E is not proposing to equalize the Silverado rate with the Redwood and Baja rates, or the Core and Noncore rates.[265]

To understand the options available to a gas shipper under PG&E's proposal, ORA posed the following hypothetical to PG&E: A gas shipper in PG&E's territory does not have any Redwood or Baja backbone transportation, and needs to get gas delivered to a specific location on PG&E's system. PG&E was asked to describe all the options available to the gas shipper. ORA wanted to determine whether the gas shipper will have to buy only from the PG&E Citygate in order to get the gas delivered to where the shipper needs it to be. PG&E was asked to make certain assumptions if the hypothetical lacked certain assumptions that are necessary in order for PG&E to respond. PG&E responded:

> A shipper cannot move gas from the border (on the Redwood or Baja Path) or from California gas production (on the Silverado Path) to Citygate without a capacity contract and without paying a transportation charge. Once the gas is at Citygate, it can be traded through PG&E's pooling system. It can also be injected into storage and later withdrawn for sale at Citygate. All supply at Citygate is available to be transported to any end-use customer anywhere in PG&E's service area under one of the end-use customer tariffs such as G-NT or G-EG. The customer must pay the applicable rates under the end-use tariff.[266]

PG&E's response explains that a shipper must have a capacity contract with PG&E and pay for the transportation charge in order to bring gas to the Citygate. Faced with equalized backbone transmission rates, the shippers will likely use the path which results in the lowest overall delivered cost of gas to them. The shippers will choose the gas basin that offers the most attractive price and the transmission path that has the least cost. Whether the gas shippers taken together will bring in more gas on both the Redwood and Baja paths such that it will result in applying downward pressures on the

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[265] PG&E Response to ORA-DR-15-Q5h.

[266] PG&E Response to ORA-DR-15-Q5g.

PG&E Citygate price, as PG&E asserts, has not been demonstrated by PG&E with any evidence. PG&E has not met its burden of proof in this rate case.

ORA notes that since 1998, the Core Redwood rate has had a price differential with the Baja rate.[267] In 1998, that price differential was approximately 4 cents in favor of the Core Redwood rate.[268] This differential has grown steadily over the years.[269] In Gas Accord IV, the settled rates created a $0.025 per decatherm price differential between the Noncore Redwood and Noncore Baja rates.[270] In Gas Accord V, the settled rates created a $0.025- $0.040 per decatherm price differential between them, with Baja rates being higher.[271] Equalization of the rates on the backbone paths would mean a zero price differential between Redwood and Baja. PG&E states:

> In Gas Accord V Settlement, the parties agreed to establish non-cost based rate differentials for core and noncore customers between the Redwood and Baja paths. PG&E is proposing to eliminate these artificial rate differentials through PG&E's equalized rate proposal.[272]

PG&E's proposal means an absolute zero price differential.[273] An absolute zero price differential, as proposed by PG&E, is also a non-cost-based rate differential, similar to the negotiated rate differentials of the past Gas Accords. There are cost-based reasons that explain why the Baja rate is higher. PG&E itself states that Baja's revenue requirement is higher.[274] PG&E further states that the upstream supplies on the Redwood Path are generally cheaper at present, thus making the Baja Path the

[267] PG&E Responses to ORA-DR-15-Q5b.

[268] PG&E Responses to ORA-DR-15-Q5b.

[269] PG&E Response to ORA-DR-15-Q5bAtch1.

[270] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-20.

[271] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-20.

[272] PG&E Response to ORA-DR-15-Q3a.

[273] PG&E Response to ORA-DR-15-Q5a.

[274] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-21.

non-preferred path and the marginal supply source.[275] More importantly, it has not been shown by PG&E how equalizing rates will generate the downward pressures on the price of gas at the PG&E Citygate. According to PG&E:[276]

> Generally, the price of gas at PG&E Citygate is a function of the cost of the upstream marginal (or swing) supply of gas plus the variable cost of transporting it on the relevant backbone transmission path, plus fuel shrinkage. Which variable transportation cost applies to the marginal supply depends on how much of that path's firm capacity is under contract.

Generally speaking, it is proper regulatory practice to assign costs to the sources that cause such costs to be incurred. ORA recommends using traditional cost-based path differentials. ORA estimates that its recommendation result in a $0.1843 per decatherm cost-based price differential between Core Redwood and Baja transmission rates in TY 2015 while an estimated $0.1162 per decatherm cost-based price differential will be between the Noncore Redwood and Baja transmission rates.

Based on the foregoing, ORA recommends that the Commission reject PG&E's proposal to equalize the Redwood and Baja backbone transmission rates for Core and Noncore customers. Instead, the Commission should retain the traditional cost-based rate design for the Redwood and Baja backbone transmission paths that exist today.

[275] PG&E Prepared Testimony, Volume 2 (Christopher), p.10-21.

[276] PG&E Response to ORA-DR-15-Q5f.