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

Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms.	Rulemaking 11-02-019 (Filed February 24, 2011)

PACIFIC GAS AND ELECTRIC COMPANY'S PIPELINE SAFETY ENHANCEMENT PLAN (PSEP) COMPLIANCE REPORT

LISE H. JORDAN
KERRY C. KLEIN

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-3251
Facsimile: (415) 973-5520
E-Mail: KCK5@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: July 30, 2014

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**PACIFIC GAS AND ELECTRIC COMPANY'S
PIPELINE SAFETY ENHANCEMENT PLAN (PSEP)
COMPLIANCE REPORT**

I. INTRODUCTION

Pursuant to Ordering Paragraph 10 of Decision 12-12-030, attached is PG&E's PSEP Quarterly Compliance Report, for the reporting period April 1, 2014 through June 30, 2014.

Respectfully Submitted,

LISE H. JORDAN
KERRY C. KLEIN

By: */s/ Kerry C. Klein*
KERRY C. KLEIN

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-3251
Facsimile: (415) 973-5520
E-Mail: KCK5@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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PACIFIC GAS AND ELECTRIC COMPANY

PIPELINE SAFETY ENHANCEMENT PLAN (PSEP) COMPLIANCE REPORT

NO. 2014-02

REPORTING PERIOD
APRIL 1, 2014 – JUNE 30, 2014

IN COMPLIANCE WITH CPUC DECISION 12-12-030

SUBMITTED JULY 30, 2014

PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE SAFETY ENHANCEMENT PLAN (PSEP)
COMPLIANCE REPORT
NO. 2014-02
REPORTING PERIOD
APRIL 1, 2014 – JUNE 30, 2014
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PACIFIC GAS AND ELECTRIC COMPANY
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Introduction

In response to the California Public Utilities Commission's (CPUC or Commission) order in the Gas Pipeline Safety Order Instituting Rulemaking (R.) 11-02-019, Pacific Gas and Electric Company (PG&E) filed its Pipeline Safety Enhancement Plan (PSEP or Implementation Plan) on August 26, 2011 with the goal of enhancing safety and improving operations. Subsequently, the Commission issued Decision (D.) 12-12-030 on December 28, 2012. Ordering Paragraph (OP) 10 of that decision directs PG&E to file and serve quarterly compliance reports to keep the CPUC and the public informed of PG&E's progress and actual cost experience related to the Implementation Plan. Per OP 10, the PSEP Compliance Reports are to be submitted in compliance with instructions set forth in Attachment D of the decision, which is separated into 29 specific requirements.

PSEP Compliance Report No. 2014-02 is submitted in compliance with the instructions set forth in Attachment D and reflects the reporting period of April 1, 2014 to June 30, 2014. It is being served on the directors of the Commission's Energy Division and the Safety and Enforcement Division, and to the service list in R.11-02-019. It will also be posted on the PG&E website at http://apps.pge.com/regulation.[1]

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1 Click on "Search" under Public Case Documents. Select "Gas Pipeline Safety OIR" from the "Case" dropdown menu. Select filing date of July 30, 2014 to narrow the search criteria. Then click "Search."

Summary

PSEP is an essential part of PG&E's commitment to rigorous safety standards, improved operations, and better service for its customers and the public.

Since program inception in 2011 through June 30, 2014, PSEP costs have totaled approximately $1.84 billion, with shareholders funding more than $985 million of that amount.[2]

As a result of the commitment and investment from program inception to June 30, 2014, PG&E's accomplishments through PSEP include:

- Completing 566 miles of strength testing.[3]
- Replacing 87.6 miles, dowrating 11.6 miles and retiring 8.7 miles of pipeline.
- Upgrading 201 miles of pipeline to accept In-Line Inspection (ILI) technology, of which 90 miles have already been in-line inspected.
- Automating 157 valves.
- Completing the records collection and Maximum Allowable Operating Pressure (MAOP) validation of PG&E's entire transmission pipeline system.[4]
- Making material improvements in PG&E's records processes and tools.

The following table highlights the progress of PG&E's construction activities during the second quarter of 2014 and on a year-to-date (YTD) basis.

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2 PG&E's PSEP Update Application, filed on October 29, 2013, provided PG&E's updated scope and proposed cost recovery of capital expenditures and expenses for the Pipeline Modernization Program (pipeline replacement and strength testing) per D.12-12-030.

3 Includes 51.1 miles proposed in PG&E's PSEP Update Application to be funded outside of PSEP.

4 PG&E completed MAOP validation of all its gas transmission pipelines in July 2013. Although PG&E has already validated MAOP for its gas transmission pipelines, PG&E engineering re-validates records of prior strength tests to meet the "traceable, verifiable and complete" standard upon planning for the execution of 2014 work.

TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF PSEP CONSTRUCTION ACTIVITY
QUARTER ENDING JUNE 30, YEAR-TO-DATE, INCEPTION-TO-DATE (ITD) AND REMAINING WORK

	Q2 2014	YTD 2014	Program ITD	Remaining PSEP Work(a)
Pipeline Replacement (miles)	2.7	4.1	107.9	35.6
• Replacement	2.7	4.0	87.6	
• Downrate(b)	0.0	0.0	11.6	
• Retirement(c)	0.0	0.0	8.7(d)	
Strength Testing (miles)	25.3	27.4	566.0	91.7
In-Line Inspection (ILI) (miles)	0.0	12.1	90.0	144.0
Pipeline Upgrades to Allow ILI (miles)	0.0	6.7	201.0	0.0
Valve Automation (valves)	16	23	157	71

(a) Remaining work for pipeline replacement and strength testing based on the updated scope from PG&E' PSEP Update Application, filed on October 29, 2013. Remaining work for ILI inspection, ILI upgrades and valve automation are based on PG&E's Implementation Plan, filed on August 26, 2011. Remaining PSEP work is subject to change.

(b) To downrate a transmission pipeline is to lower its operating pressure to that of distribution pressure (60 pounds per square inch gauge (psig) or less).

(c) To retire a pipeline is to remove it from service and not replace it with any other pipe.

(d) 0.02 miles associated with strength test are funded outside of PSEP.

In addition to the units completed as shown in Table 1, in the current reporting period, PG&E has delivered tangible improvements to the safety of the gas transmission system, met key program milestones, and demonstrated material improvements in project success criteria, including:

- Continued improvement in overall safety performance, reducing safety incidents in the current reporting period by approximately 49 percent compared to the same period in 2013. With nearly one million construction-related hours completed in 2014. Lost Work Day Cases[5] and Serious Preventable Motor Vehicle Incidents[6] remain on track to meet or exceed year end targets.

5 Lost Work Day Cases measure the number of Lost Work Day Cases incurred for employees and staff augmentation per 200,000 hours worked, or for approximately every 100 employees. A Lost Work Day Case is a current year Occupational Safety and Health Administration Recordable incident, which is considered an occupational injury or illness that requires medical treatment beyond first aid, or results in work restrictions, death, or loss of consciousness.

6 Serious Preventable Motor Vehicle Incidents measure the number of serious preventable motor vehicle incidents which a driver could have avoided, per 1,000,000 miles driven. The incident is considered serious if one of the following criteria is met: (a) injuries are treated away from the scene of the incident; (b) a vehicle must be towed; and/or (c) PG&E vehicle damage exceeds $5,000.

- Continued improvement in environmental compliance performance, with compliance incidents remaining on track to meet or exceed year end targets which reflect a 10 percent improvement on 2013 actual performance.
- Held the fourth Construction Alliance Executive Session between the leadership of PG&E Gas Transmission and all four Gas Transmission Construction Alliance Contractors. The team reviewed Strategic Construction Alliance results including: safety performance, better environmental compliance, improved quality in general, and more efficient project execution. The team discussed how the Alliance is working together to improve safety for all partners, examples include an increase in the number of good catches, excavation knowledge sharing, etc. The team reviewed the PAS 55[7] efforts resulting in PAS 55 and ISO 55001[8] certification, as well as ongoing efforts required to maintain certification. Additionally, the team discussed Alliance related processes and results to explore areas of success and opportunities for improvement.
- Delivered earlier completion of design and engineering of this year's project portfolio, as compared to 2013, having reached at least the 90 percent engineering completion milestone on approximately 81 percent[9] of a total 160[10] PSEP Pipe Replacement, Strength Test, ILI and Valve Automation projects, out of projects, compared to 68 percent at this same date in 2013.
- Successfully remediated two pipeline leaks/failures identified during strength testing, which resulted in approximately 111 feet of pipeline replacement.

Notwithstanding these successes and process improvements, PG&E faces challenges in completing a small subset of the projects scheduled for 2014 by the end of 2014 as a result of delays in securing land rights and obtaining construction permits. Due to these challenges, there is an increasing risk that PG&E may not be able to construct all of its planned PSEP pipe replacement, strength test, ILI or valve

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7 PAS 55 is the British Standards Institution's (BSI) Publicly Available Specification for the optimized management of physical assets. It provides clear definitions and a 28-point requirements specification for establishing and verifying a joined-up, optimized and whole-life management system for all types of physical assets.

8 ISO 55001 specifies requirements for an asset management system within the context of the organization.

9 On a project count basis, excluding shorter duration projects (e.g., pipeline shorts).

10 Excludes 48 Replacement Shorts projects planned for 2014. PG&E has 208 PSEP projects planned for 2014.

automation projects in 2014. Approximately 1 percent of aggregate work on Pipe Replacement, Valve Automation, In-Line Inspection and Upgrades has been deferred to 2015. This does not change PG&E's commitment to do the work. Project teams are actively coordinating mitigation efforts, to complete this work as efficiently as possible as we strive to become the safest, most reliable utility in the U.S.

Table 2 provides a summary of the PSEP activities and actual costs for the reporting period. Please see the response to Question 20 for further detail.

TABLE 2
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF PSEP FILED VS. ACTUAL COSTS BY WORKSTREAM
REPORTING PERIOD APRIL 1 – JUNE 30, 2014 (IN MILLIONS OF DOLLARS)

	2011 PG&E Filing Estimate	Authorized Program Costs [Original Filing](a)	2013 Proposed Program Costs [Update Application](b)	Actual Costs Program Inception-to-Date (2011 – 06/30/14)(c)(e)	Actual Costs Reporting Period (04/01/14 – 06/30/14)(c)
Pipeline Modernization					
Pipeline Replacement	$839.1		$534.1	$625.6	$38.6
• Replacement(e)				620.8	38.6
• Downrate				0.1	0.0
• Retirement				4.7	0.0
Strength Testing	456.8		160.2	629.1	48.6
In-Line Inspections/Upgrades	39.9		38.8	62.1	0.8
Subtotal	**$1,335.8**	**$1,002.0**	**$733.2**	**$1,316.8**	**$88.0**
Valve Automation	143.6	135.7	135.7	121.0	13.9
Pipeline Records Integration	286.0	0.0	0.0	334.0	6.9
Interim Safety Enhancement Measures	3.2	2.1	2.1	5.2	0.3
Program Management Office (PMO) and Other(d)	34.8	28.9	28.9	59.2	5.8
Risk-Based Contingency	380.5	0.0	0.0	0.0	0.0
Total	**$2,183.9**	**$1,168.8**	**$899.9**	**$1,836.2**	**$114.9**

(a) Authorized amounts as provided in Attachment E, Table E-4, of D.12-12-030. The authorized amounts for pipeline replacement and strength testing may change in the future, pending the outcome of PG&E's PSEP Update Application filed on October 29, 2013.

(b) Update Application amounts as referenced in costs requested in the October 29, 2013 PSEP Update Application, in A.13-10-017, detailed in the Workpapers Supporting Chapter 2, Table 2-1, "Capital Expenditures and Expenses by Maintenance Activity Type (MAT)."

(c) Includes Stanpac costs incurred of approximate $10.13 million and $ 0.09 million, on a program inception-to-date basis and for the reporting period, respectively. Amounts include reallocation of prior period amounts consistent with PSEP scope decisions and cost allocation.

(d) "Other" includes costs of activities pending assignment to an individual workstream or determined as not directly associated with an individual workstream.

(e) For a portion of miles, PG&E was unable to allocate the actual recorded costs for retirements and downrates that were part of a larger replacement project

Decision-Making Process

1. Project Planning and Prioritization of Work

Describe PG&E's project planning process including how the projects were and are being scheduled and sequenced and what measures were and are being taken to conduct the work in a cost effective manner.

Response

PSEP's prioritization and scheduling processes remain consistent with the descriptions previously provided in PSEP Compliance Report No. 2013-01 and testimony supporting PG&E's August 26, 2011 Implementation Plan.[11] During the second quarter of 2014, work prioritization for pipeline replacement and strength testing projects has been driven by the results of applying PSEP Decision Trees to validated pipeline segment attribute data as presented in PG&E's PSEP Update Application (A.13-10-017). Work prioritization for valve automation and ILI projects continues to be driven by the results of applying PSEP Decision Trees to pipeline segment attribute data as detailed in PG&E's August 2011 Implementation Plan.

PG&E is actively seeking to address all challenges in executing all of its remaining Phase 1 planned projects in 2014.[12] Schedule dependencies related to the acquisition of land rights, construction permits, and environmental permits on approximately 10 pipeline replacement, 1 ILI, and 1 valve automation projects may likely result in a delay of construction commencement.[13] This represents, approximately 1 percent of aggregate work on pipe replacement, valve automation, in-line inspection and upgrades and does not change PG&E's commitment to do the work.

As previously reported in prior PSEP Compliance Reports, PG&E had been able to mitigate the impact of similar schedule dependencies and resultant delays by accelerating projects from later years in Phase 1. In 2014, the last originally scheduled year of Phase 1 construction, the measures described above are not

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11 PG&E PSEP Implementation Plan (R.11-02-019) Prepared Testimony, Chapter 3 – Gas Transmission Pipeline Modernization Program, Section A.5, and Chapter 4 – Gas Transmission Valve Automation Program, Section K.1.

12 Three projects currently have a tie-in/operative date of 2015.

13 The number of projects may change, as will the resultant magnitude of impact, depending on risk factors including: land rights, environmental permits, and other permits.

possible as the planned 2014 projects reflect the remaining scope of PSEP Phase 1. Even small delays to projects could move construction and operational dates into 2015. PSEP project teams are proactively working to manage and complete the ongoing work by actively coordinating mitigation efforts, designed to minimize the potential impact of these scheduling risks.

Table 1-1 in the Appendix provides details on the current population of 12 individual projects across PSEP construction workstreams that are at material risk of not being complete by December 31, 2014. With respect to these projects, Table 1-1 includes project descriptions, miles affected and drivers for potential project delays.

As of June 30 and on a year-to-date basis, 2014 program spend remains consistent with overall completion. Currently individual work streams are actively focused on effectively implementing construction plans that incorporate identified cost effective approaches (e.g., use of horizontal directional drilling, both shallow and deep). Current schedules indicate that peak construction will occur during the third quarter of 2014.

In addition, project scheduling in the current reporting period has incorporated ongoing assessments of pipeline system operational safety, customer service requirements, clearance availability, permitting restrictions, and cost-effectiveness. Material project-level changes to scope and schedule, during the reporting period, as a result of these processes are also provided within the "Comments" column of the table responses to Questions 11 through 13.

TABLE 1-2
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 1-1 COLUMN REFERENCE

Column Name	Description
Line #	Reference number for this report.
New PSRS	PSRS number provided in workpapers supporting PG&E's PSEP Update Application for pipeline replacement or strength test projects commonly resulting from project split or addition.
Probability of Delay Past 2014	Probability that the current risk materializes and pushes the project schedule past December 31, 2014.
Project Description	Order Description provided in workpapers supporting PG&E's August 26, 2011 filing for valve automation, ILI, and upgrades for ILI. Order Description provided in workpapers supporting PG&E's October 29, 2013 PSEP Update Application for pipeline replacement and strength testing.
City	Location of project.
Mobilization Date	Currently scheduled project start date.
Tie-In Date/Operative Date	Anticipated project finish date.
Job Miles/Valves at Risk	Number of miles at risk of non-completion by December 31, 2014.
Drivers of Potential Project Delay	A description of underlying reasons why PSEP construction projects may be at risk of non-completion by December 31, 2014.

Resource Procurement and Oversight

2. Resource Planning

Explain how PG&E decided whether to do the work in-house (e.g., use own employees and equipment) or contract the work out to other parties.

Response

PSEP's resource planning process remains consistent with the description previously provided in PSEP Quarterly Compliance Report No. 2013-01. To ensure that Implementation Plan work is completed on a timely basis, PG&E has implemented a resource management model whereby the skills and experience of PG&E employees are augmented by contractor resources. PG&E also uses contractor resources where it has identified the need to efficiently leverage new skills or equipment within an accelerated timeframe, or where the use of a contractor provides additional expertise.

During the current reporting period, program activities related to the selection of contractors have included, but are not limited to:

- Ongoing review of results of safety, environmental, and quality assurance inspection activities at construction contractor project sites.
- Bi-weekly regional work allocation meetings to monitor, prioritize and coordinate individual project resourcing by Alliance construction contractors; regional work being identified as an outcome of a work allocation process conducted in partnership with PG&E Gas Transmission General Construction (GTGC).
- Quarterly Construction Alliance Executive Session meetings between the leadership of PG&E and all four Alliance contractors.

3. Contractor Selection Process

For work contracted out to other parties, what criteria did PG&E use to select the contractors and did PG&E use a competitive bidding process to select the contractor(s)? If not, explain why.

Response

No material changes in PG&E's contractor selection and competitive bidding processes, as previously outlined in the PSEP Compliance Report No. 2013-01, have been made during the current reporting period.[14] PSEP continues to employ an Alliance construction contractor delivery model for its 2014 PSEP construction projects, which integrates available resources from PG&E GTGC with Alliance construction contractors. The majority of the 2014 portfolio of projects has been allocated with approximately 69 percent of the work assigned[15] to the four Alliance contractors. The primary objectives of the Alliance strategy remain the establishment of best-in-class safety performance, a robust construction delivery model, and the maintenance of a qualified and skilled workforce to perform work planned. PG&E's Master Service Agreement (MSA) is being revised to incorporate lessons learned during 2013. The Alliance model includes the following key components:

Resources and Planning

- Consistent "A" team availability and scalable crew composition.
- Commitment to provide early constructability feedback via joint planning and co-location.
- Bundling of work across PSEP workstreams and within four regional areas that span PG&E's entire service area to reduce "peaks and valleys" in resource requirements.
- Collaboration on industry best practices and lessons learned.

Performance Measurement

- Increased transparency and alignment across construction cost estimation models using negotiated standardized "open book" labor and equipment rates and consistent overhead (general and administrative) expenses.

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14 PSEP construction contracts are competitively bid when PG&E and Alliance contractors are unable to negotiate a target price. As reported in PSEP Compliance Report No. 2013-03, one such instance occurred in 2013.

15 Work assigned is based on the value of total portfolio.

- Shared project risk/incentive model using a negotiated “target pricing” model, in which under and over runs are shared on a 50:50 basis.
- Project completion cost true-up and lessons learned—costs being fully auditable where appropriate.
- Five-year agreement with cancellation off ramps, including option to bid any portion of work to maintain pricing/cost discipline.
- Semiannual program score carding and quality leadership reviews.

Construction-related project activities performed outside of either the Alliance contracting process or PG&E’s GTGC are assigned to existing suppliers using existing MSAs that were previously subject to competitive bidding, or assigned on a Direct Award basis, based on the nature of the specific services required by the project.[16]

16 Please refer to PSEP Compliance Report No. 2013-01, Question 3, p. 11, for a description of Direct Award.

4. Quality Assurance – Outside Contractors

How does PG&E monitor the quality of work performed by outside contractors? Has PG&E found any instances where a contractor failed to do the work properly? If so, what actions did PG&E take in response?

Response

No material changes in PG&E's procedures that monitor the quality of work performed by outside contractors (as previously outlined in prior PSEP Compliance Reports) occurred in the current reporting period.

PG&E has found instances where the contractor did not perform quality work according to PG&E's internal standards. In such situations, and as appropriate, PG&E takes specific actions to maintain the integrity of its gas transmission system and to ensure such instances do not reoccur. Examples of such quality monitoring activities at gas transmission construction projects and related issues identified during the reporting period include:[17]

- PG&E's Quality Assurance/Quality Control (QA/QC) department performed 352 field assessments in the second quarter of 2014. These field assessments were conducted on 82 individual projects throughout PG&E's service territory. Twenty two Corrective Action Notices (CANs) were issued by PG&E QC which covered a variety of Non-Conformance Issues including Documentation Errors, Dry Film Thickness Readings, Improper Jeeping[18] of the Coatings, and Mis-Labeling of Non Destructive Examination X-Ray Films. These CANs are being tracked to resolution by PG&E's QA/QC department and are being logged into PG&E's Corrective Action Program (CAP) for trending and tracking purposes. To avoid reoccurrence and to increase awareness among field personnel, all issues are communicated by the QC assessor to the lead inspector or field engineer at the time of discovery. In addition, the QC assessor provides information explaining the nature of the quality issue (i.e., providing direction on proper documentation, and issues a QC CAN). On April 15, 2014, QC performed a Coatings Assessment on the V-056 Valve Automation Project in Brentwood. It was discovered during the assessment that the Dry Film Thickness (DFT) readings on four different days

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17 The information provided includes contractors and employees.

18 Jeeping is the common term for inspections of pipeline coatings using electronic defect detectors.

for a total of 42 locations exceeded the Maximum Allowable DFT of 40 millimeters. A Corrective Action Notice was generated and was subsequently closed when PG&E Bulletin TD-E-35B-001 was issued and changed the DFT requirements and aligned them with the coatings suppliers Product Data Sheets. On May 27, 2014, QC performed a Coating Assessment on "RT-036 DREG4050-SA Repl Ph 1" in Sacramento. During the assessment, QC found that the Coatings had been "Jeeped" at 2,500 Volts (V) instead of the 3,125 V required under PG&E Bulletin TD-E-35B-001. A CAN was generated and reviewed with the Site Personnel. On July 2, 2014, QC followed up with another site visit and found the sections of the pipe that were not "Jeeped" at the correct voltage, had been Re-Jeeped at the 3,125 V in conformance with PG&E Bulletin TD-E-35B-001. The Corrective Action Issues were found to be in compliance and the Corrective Action Notice was closed.

- The Construction Leadership team (i.e., GTGC and Alliance Contractors) has completed 465 job-site safety observations. Through these observations, 87 observable items were identified. All of the observable items were mitigated to align with the on-site contractor site-specific safety plan. As a result of job-site safety observations, 388 "good catches"[19] were identified, addressed and communicated to every contractor or employee working on a PG&E project to raise worksite safety awareness.
- PSEP Leadership Observation Teams visited 54 construction sites to engage work crews regarding safety, quality and to promote best practices.[20]
- PG&E completed 1,927 environmental inspections to monitor and ensure compliance with PG&E standards. The environmental inspections identified 105 minor deficiencies,[21] 6 compliance issues,[22] and 1 non-compliance

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19 "Good catches" are potentially unsafe situations that were brought to site personnel's attention and rectified.

20 The PSEP Leadership Observation Team visits construction project sites to ensure safety compliance and to promote best practices.

21 A minor deficiency is a correctable item that does not have a significant impact on resources or environmental resources.

22 A compliance issue is a situation or minor problem that needs to be addressed immediately to prevent resource damage or environmental noncompliance.

issue.[23] Each of these issues have been addressed through correction actions. The resulting lessons learned and process changes, as applicable, are shared with environmental staff, construction contractors, and GTGC at tailboards and weekly regional Alliance Contractor meetings.

- As reported in the Q1 PSEP Compliance Report, on March 25, 2014, while deactivating a portion L-172A, in West Sacramento, a PG&E contractor working on pipeline replacement project R-037, inadvertently penetrated L-116, a transmission line operating at 680 psig which runs parallel to L-172A in that area. This action resulted in an uncontrolled release of gas. No one was injured and the pipeline was immediately taken out of service and repaired. PG&E's internal cause evaluation investigation of this event identified a number of process and activity oversight issues. PG&E is pursuing a series of internal recommended actions to address causes and will also incorporate additional steps that may be identified after the completion of the contractor's own root cause analysis, as appropriate.

23 A non-compliance issue does not fulfill PG&E's internal environmental requirements and results in an impact on resources or places environmental resources at risk.

5. Quality Assurance – Internal Resources

What quality assurance procedures does PG&E have in place to determine whether the project work is being done correctly by its own employees? Has PG&E found any instances where the work was not done properly? If so, what actions did PG&E take in response?

Response

No material changes in PG&E's procedures that monitor the quality of work performed by internal resources (as previously outlined in prior PSEP Compliance Reports) occurred in the current reporting period.

PG&E has found instances where employees did not perform quality work. In such situations, and as appropriate, PG&E takes specific actions to maintain the integrity of its gas transmission system and to ensure such instances do not reoccur. Please refer to the response to Question 4 for examples of such quality issues identified during the reporting period.

6. Project Management Office Overview

Describe the role of the Program Management Office (PMO) (see p. 7-10 of Prepared Testimony) in containing project costs. Provide specific examples where the PMO's recommendations led to cost savings.

Response

The role of the PMO, as described in the prepared testimony referenced in the question above, remains unchanged and its objectives can be summarized as follows:

- To help manage the overall Program execution and to coordinate the activities of interrelated projects or workstreams.
- To provide oversight and provide observations and recommendations for process improvements and enhanced performance.
- To provide assurance that Program control tools and procedures are operating in the way they are intended to achieve Program objectives.

The operation of each of the groups within the PSEP PMO support these objectives, and in doing so, contribute to the cost-effective execution of the Implementation Plan. While it is not possible to disaggregate and quantify individual cost savings impacts, during the current reporting period, the PSEP PMO has continued to work with each workstream on a series of improvement initiatives that are designed to lead to cost savings. These initiatives include, but are not limited to:

- Continuous Improvement and Lessons Learned:
  - <u>Cross-Functional Teams</u>: To improve project execution and to coordinate the activities of interrelated projects or workstreams, the PSEP PMO established and is coordinating small cross-functional teams focused on developing process improvements. The teams explore, define, and manage these initiatives, coordinating across functional groups including: engineering, GTGC, construction management, environmental, sourcing, land, and contract management.
- Construction Contractor Alliance:
  - <u>Project Performance Measurement and Target Pricing</u>: As part of the continued implementation of an Alliance construction contractor delivery model, the PSEP PMO has developed and continued the implementation of a performance measurement process. This process finalizes approved

change orders and incorporates cost validation activities with Alliance construction contractors that ultimately result in "true-up" payments to or from the construction contractor (based upon a 50:50 sharing of validated costs in excess of, or below, the final target price). Within the current reporting period, PG&E completed 33 project true-ups. Forty-nine projects in total have completed true-up with realized savings to PG&E of approximately $1.4 million or approximately 1.5 percent of the aggregate project final target prices. Extended change order and cost validation negotiations and processing as well as gathering, receipt, and review of actual costs from Alliance Partners has increased the time required to true-up and close out projects. PG&E and the Alliance contractors are working diligently to validate costs on the remaining 2013 completed construction projects.

  - Construction Resource Availability and Efficiency: In order to mitigate any project delays and to ensure consistent and sustained access to "A-team" resources, the PSEP PMO continues to lead weekly review meetings with the Alliance construction contractors. These meetings discuss resource issues (e.g., mitigating individual project delays by bringing forward work on future projects) and bundled work in an assigned geographical region.
  - Continuous Improvement and Lessons Learned: In partnership with the PSEP PMO, Shared Services gathered Alliance-contractor-identified potential improvements and integrated these into the continuous improvement initiatives, as noted above.

- Extending the Capabilities of PG&E's Construction Management Tool:
  - Construction Management Tool (Unifier): To further increase the efficiency of construction management activities, the PSEP PMO has extended access and workflow capabilities to the engineering group and GTGC in the second quarter of 2014. During the current reporting period the PMO has commenced the pilot of automated workflow supporting the Alliance cost validation process and is reviewing the potential application of similar workflow automation to the Alliance contract true-up process. The PSEP PMO team currently supports more than 400 users on this

system responding to requests for information, and approving construction change orders.

- Enhancing Performance Management:
  - Enterprise System Portal (ESP): The PMO has developed ESP to allow Portfolio Managers, Project Managers and Supervisors to have a common view of currently available portfolio and project-level cost and schedule information. This system increases the efficiency of the PMO by reducing the need to develop and maintain additional report formats. ESP was partially deployed in the second quarter of 2014.
  - Risk Management Tool (Active Risk Manager): The PMO has continued its development of risk management processes supporting the program, increasing the consistency of identification and update of risk assessments and mitigation activities within the risk management tool. In addition the risk management team provides material project forecast input by completing quantitative risk assessments with the project management team.

A broader list of lessons learned is being implemented and tracked within each workstream and is provided in response to Question 17.

7. Project Management Office Costs and Benefits

Provide the costs incurred by the PMO year-to-date and describe the specific work they did for the benefit of PG&E customers.

Response

The PSEP PMO incurred approximately $2.9 million during the period April 1 to June 30, 2014. Consistent with PG&E's commitment to customers to provide safe, reliable, and affordable gas service, the PSEP PMO is responsible for the successful delivery of all projects within PG&E's Implementation Plan.

Since the beginning of the program, the PSEP PMO, in partnership with project teams and cross-functional leads (such as PG&E's Customer Care and Corporate Communications organizations) has focused on many areas that directly benefit PG&E customers including:

- Improving Construction Site Safety: Implemented a series of safety-focused activities designed to improve construction site safety for employees, customers, and local communities, including leadership site visits, "good catch" or "near hit" reporting, after-hours site security audits, and job hazard mitigation analyses. In addition, the program maintains metrics that measure performance against safety improvement targets for construction-related public safety incidents and at-fault "dig-ins." PG&E's 2014 safety targets for these metrics and other safety performance measures have been set on a consistent basis across all of PG&E's gas transmission construction activities. These metrics target significant improvements in safety performance, as compared to 2013, for both Alliance construction contractors and GTGC. Through the end of the current reporting period, all safety performance metrics are on track to meet or exceed their respective 2014 targets. As of June 30, 2014, the recordable incident rate on gas transmission construction activities was 1.00.[24]
- Improving Environmental Compliance: Inspection findings and feedback to PG&E and contractor construction resources have focused on addressing compliance performance related to approved soil off-haul procedures, storm water management plans, dust control readiness and implementation, and

24 The recordable incident rate includes hours worked by Alliance contractors, Construction Management inspectors, and PG&E General Construction resources on PSEP construction projects.

fire prevention and response readiness. As of June 30, 2014, PSEP remained significantly ahead of plan to meet or exceed a 10 percent reduction in inspection findings compared to its 2013 environmental compliance incidence rate.

- Maintaining Consistency of Pre-Construction Customer Communications: During the current reporting period, PG&E has consistently communicated with customers on PSEP-related activities through distributing pre-venting notifications, hosting open houses, and providing customer communication materials.
- Improving Customer Outage Management: PG&E continued to leverage its increased Compressed Natural Gas/Liquefied Natural Gas (CNG/LNG) fleet. Project planning improvements implemented during 2014 deliver earlier and better visibility into customer demand requirements and enable more efficient planning of CNG/LNG resources and flexibility with customer schedules. This improvement has helped minimize planned customer outages and reduce the risk of unplanned customer outages.

Finally, the PSEP PMO's role during the current reporting period continued to include many activities that also indirectly support customer services, including the implementation and management of consistent program controls, risk management, and governance, quality control, reporting, and initiatives designed to improve project success and increase cost efficiencies.

Budget and Spending

8. Factors Impacting Cost Effectiveness

Describe any factors, either internal or external, that may have prevented or affected PG&E from conducting the work in a more cost effective manner. Quantify the cost impact of such factors.

Response

PG&E's PSEP has consistently identified project uncertainties, and implemented risk mitigation activities and remediation measures. Despite best efforts, PG&E has not been able to fully mitigate the potential impact of cost uncertainties. Factors that have driven these cost impacts in projects completed in the current reporting period include:

- Project Definition: Changes in project scope upon completion of data validation and prioritization of individual pipeline segments to maintain system integrity and public safety (i.e., shortened project lengths, increased project counts, and reduced development schedules).
- Pipeline Routing Restrictions: Increased complexity and cost of pipeline routing due to the limitations on the use of urban franchise areas, existing utilities, and infrastructure (i.e., increased construction costs and duration).
- Geographical Conditions: High water table, trench dewatering costs, poor or weak soil, excessive permitting conditions, site specific contamination, and excessive waste disposal fees (i.e., increased construction costs and duration).
- Permitting and Land Rights: Delays and uncertainty in receiving permits from state and local authorities while acquiring additional land rights from customers (i.e., project forced to adopt costly "in-road" construction within franchise rather than being able to pursue more cost-effective verge construction that is subject to extended permitting timelines.) Increased permitting conditions, restricted work hours to avoid road/lane closures during heavy commute hours (i.e., compacted construction schedules).
- Unidentified Pipeline Field Conditions: Additional construction activities, including pipeline cleaning (to meet unique wastewater disposal requirements), the removal of pipeline anomalies, the repair and replacement of pipe, valves and fittings due to condition, construction obstructions, and

re-engineering due to previously unidentified non-PG&E structures or other utilities (i.e., increased construction duration and costs).

- Gas System and Customer Service Constraints: Limited availability of gas system clearances due to seasonal customer demand and system operations, safety related pressure reductions, CNG/LNG resource requirements, and the availability of PG&E and contract construction crews to complete tie-ins—particularly during peak summer construction periods and towards the end of the calendar year (i.e., increased construction durations and costs).

Our response to Question 19 provides PG&E's most recent risk management assessment with a project-by-project analysis of unexpected or unforeseen items that have affected 2014 completed projects and the resulting cost and schedule impacts.

9. Procurement Policy and Practices

Describe PG&E's procurement policy and practices for pipe and other materials used for projects. Was a competitive bidding process used? If not, explain why. Describe what factors PG&E considers in procuring material ranked by importance. Identify the manufacturer(s) or suppliers of the pipe used for the replacement projects and for any material that cost more than $100,000 per item.

Response

The majority of material is purchased from existing suppliers through MSAs, the terms and conditions of which (including unit pricing) are the result of a competitive bidding process.

Material supplier selection, the competitive bidding processes, and factors previously described in PSEP Compliance Report No. 2013-01 were unchanged during the current reporting period.

Manufacturers or suppliers of the pipe used for PSEP replacement projects are:

- Berg Pipe
- Durabond Industries
- California Steel Industries
- U.S. Pipe
- Tenaris
- Voestalpine
- PTC Alliance
- Wheatland Tube

No materials procured during the current reporting period cost more than $100,000 per item.

10. Pipeline Disposition Procedures and Costs

What was the disposition (e.g., sold) of replaced pipe and other material? Identify all the amounts earned for the disposition of the material, costs incurred to transport or dispose of the material and regulatory treatment of the incurred costs and revenues.

Response

The disposition of transmission pipeline and other material replaced as part of the PSEP program—stored, hazardous waste, retired-in place or salvage—and related cost allocations as described in PSEP Compliance Report No. 2013-01 remain unchanged during the reporting period. For the quarter and year-to-date periods ended June 30, 2014, PG&E has recovered approximately $78,649 and $138,528, respectively, as a result of salvage activities.

Project Status Summaries

11. Projects Completed Year-to-Date

Provide a complete description or a specific reference to proceeding workpapers, of projects completed during this reporting period and those completed Year-to-Date, include the start and finish dates. On a project-by-project basis, provide the amount budgeted for the project and an itemized list of the costs, including labor and material, incurred completing of the project. Identify the amount that a project was over or under-budget. Indicate whether the work was done in-house or by outside contractor(s). Identify the outside contractor(s). Explain how the work was done in compliance with D.11-06-017 and PG&E's Decision Tree and, if so, provide the Decision Tree outcome identifier associated with each project. Identify costs that shareholders will absorb.

Response

Table 11-1 of the appendix provides details on 72 individual projects across PSEP construction workstreams[25] that were completed by PG&E during the current reporting period and YTD.[26] With respect to these projects, Table 11-1 includes specific reference to proceeding workpapers, including the construction start and finish dates.[27] In addition, it provides, on a project-by-project basis, the amount budgeted for the project and an itemized list of the costs (e.g., including labor and materials incurred in completing the project); the amount that a project was over or under budget; and whether the work was completed in-house or by outside contractor(s), including the identification of the outside contractor(s).

All work detailed in Table 11-1 was undertaken in compliance with D.11-06-017; each project includes pipeline segments for which a prior strength test has previously not been performed and/or for which traceable, verifiable and complete records of such a test do not exist. PG&E's Workpapers Supporting Chapter 2, Gas Transmission Pipeline Modernization Program Update, of the

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25 Includes: pipeline replacement, retirement, downrate strength testing, ILI, pipeline ILI upgrades, and valve automation. Project information is subject to update upon completion of project closeout procedures including completion of construction documentation ("as-builting"), mapping and closeout.

26 For the purposes of this report, the completion of a project is the date the pipeline segments and valves are returned to operations.

27 Construction finish date reflects completion of project tie-in, see Table 11-2.

PSEP Update Application provides descriptions of how each of the pipeline replacement and strength testing projects listed in Table 11-1 was performed in compliance with D.11-06-017, including the associated segment-level Decision Tree outcome identifier. PG&E's Workpapers Supporting Chapter 3, Gas Transmission Pipeline Modernization Update, and Chapter 4, Valve Automation Program, of the August 26, 2011 PSEP filing provides descriptions of all planned PSEP ILI and valve projects that have been or will be performed in compliance with D.11-06-017.

As PG&E progressed from the preliminary work scope and associated estimates and work plans included in its August 2011 PSEP filing, it developed more specific work plans and estimates. These refined estimates, or "Job Estimates," are used in this report for Questions 11 through 13 and 15, to represent the budgeted amount by project for a more meaningful comparison to total costs. Upon completion of the Phase 1 work scope, PG&E will have to reconcile its total incurred costs for the work scope to the amounts adopted by the CPUC in order to determine the final disposition of shareholder costs. See Table 20-1 for the total amount of costs that shareholders have absorbed YTD based upon amounts previously authorized by the CPUC, shown by month and broken down by activity.

Table 11-2 provides a reference for the specific data points requested in Question 11 to their corresponding columns in Table 11-1 of the appendix. Additional data points are included for context in navigating the tables.

TABLE 11-2
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 11-1 COLUMN REFERENCE

Column Name	Description
Line #	Reference number for this report.
PSEP Filing PSRS	PSRS number provided in workpapers supporting PG&E's August 26, 2011 filing.
New PSRS	PSRS number provided in workpapers supporting PG&E Update Application for pipeline replacement or strength test projects commonly resulting from project split or addition.
Order Number	Financial system of record reference number to track specific costs, e.g., on individual projects.
Project Description	Order Description provided in workpapers supporting PG&E's August 26, 2011 filing for valve automation, ILI, and upgrades for ILI. Order Description provided in workpapers supporting PG&E's October 29, 2013 Update Application for pipeline replacement and strength testing. Includes project reference IDs that start with a letter that reflects the construction activity or workstream (i.e., R – pipe replacement, pipe downrate, pipe retirement, T – strength testing, V – valve automation, and I – in-line inspection).
City	Location of project.
Construction Contractor	Contractor who performed the work ("GC" refers to PG&E in-house).
Mobilization Date	Project start date.
Tie-In Date	Project finish date.
Job Estimate Amount	Amount budgeted for project after completing project engineering, routing, permitting and construction bids.
Total Cost	Itemized costs per project completed.
Labor Cost	
Materials Cost	
Contracts Cost	
Other Cost (a)	
Variance to Budget	Variance between Total Cost and Job Estimate (see Question 19).
PSEP Disallowed Cost	Project costs disallowed per CPUC D.12-12-030, i.e., post-1955 pipe work (does not include any estimation of amounts in excess of individual workstream authorized expenses and capital expenditures).
Non-PSEP Costs	Project costs not recoverable within PSEP.
>10% Over Budget	Projects greater than 10 percent over Job Estimate.
Comments	Descriptions of changes to the project, including project additions, accelerations, delays, and cancellations.

(a) Other costs include costs not included in Labor, Materials, or Contracts, such as overhead.

12. Projects Started, Pending Completion

Provide a complete description, or a specific reference to proceeding workpapers, of projects that have begun but are currently unfinished, include the start and anticipated completion dates. On a project-by-project basis, provide the amount budgeted for each project. Explain how the work is being done in compliance with D.11-06-017 and PG&E's Decision Tree and, if so, provide the Decision Tree outcome identifier associated with each project.

Response

Table 12-1 of the appendix provides details on 38 individual projects across five construction workstreams where construction has commenced but the project has not yet been returned to operations (tied-in) as of June 30, 2014. Table 12-1 includes specific reference to workpapers of projects that have started construction but are not yet completed as of the end of the reporting period. Table 12-1 includes the construction start and anticipated finish dates. In addition, it provides, on a project-by-project basis, the amount budgeted for the project.

All work detailed in the table was undertaken in compliance with D.11-06-017; each project includes pipeline segments for which a prior strength test has previously not been performed and/or for which traceable, verifiable and complete records of such a test do not exist. PG&E's PSEP Update Application Workpapers Supporting Chapter 2, Gas Transmission Pipeline Modernization Program Update provides descriptions of how each of the pipeline replacement and strength test projects listed in Table 12-1 is being performed in compliance with D.11-06-017, including the associated segment-level Decision Tree outcome identifier. PG&E's August 26, 2011 PSEP filing, Workpapers Supporting Chapter 3, Gas Transmission Pipeline Modernization Update, and Chapter 4, Valve Automation Program, provides descriptions of all planned PSEP ILI and valve projects that have been and will be performed in compliance with D.11-06-017.

Table 12-2 provides a reference for the specific data points requested in Question 12 to their corresponding column in Table 12-1 of the appendix. Additional data points are included for context in navigating the tables.

TABLE 12-2
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 12-1 COLUMN REFERENCE

Column Name	Description
Line #	Reference number for this report.
PSEP Filing PSRS	PSRS number provided in workpapers supporting PG&E's August 26, 2011 filing.
New PSRS	PSRS number provided in workpapers supporting PG&E's PSEP Update Application for pipeline replacement or strength test projects commonly resulting from project split or addition.
Project Description	Order Description provided in workpapers supporting PG&E's August 26, 2011 filing for valve automation, ILI, and upgrades for ILI. Order Description provided in workpapers supporting PG&E's October 29, 2013 PSEP Update Application for pipeline replacement and strength testing.
Mobilization Date	Project start date.
Tie-In Date	Anticipated project finish date.
Job Estimate Amount	Amount budgeted for project after completing project engineering, routing, permitting and construction bids.
Comments	Descriptions of changes to the project, including project additions, accelerations, delays, and cancellations.

13. Projects Planned, But Yet to Start

Provide a complete description, or a specific reference to proceeding workpapers, of projects that were forecasted for Phase 1 that have yet to start, include the anticipated start and anticipated completion dates. Rank the priority of these projects and explain the ranking. On a project-by-project basis, provide the amount budgeted for the project. Explain how the work was done in compliance with D.11-06-017 and PG&E's Decision Tree and, if so, identify the Decision Tree outcome identifier associated with each project.

Response

Table 13-1 of the appendix provides detail on 101 individual projects across five construction workstreams where pre-construction activities have commenced but construction resources have not yet mobilized as of June 30, 2014.

Table 13-1 provides specific reference to proceeding workpapers, of projects that have yet to commence construction as of the end of the reporting period.[28] For each project, PG&E has supplied the current anticipated construction start and finish dates which reflect the updated output of the prioritization and schedule procedures or ranking noted in response to Question 1. In addition, the table provides, on a project-by-project basis, the amount budgeted for some projects.

All work detailed in the table was undertaken in compliance with D.11-06-017. PG&E's PSEP Update Application, Workpapers Supporting Chapter 2, Gas Transmission Pipeline Modernization Program Update, and provides descriptions of how each of the pipeline replacement and strength testing projects listed in Table 13-1 will be performed in compliance with D.11-06-017, including the associated segment-level Decision Tree outcome identifier. PG&E's August 26, 2011 PSEP filing, Workpapers Supporting Chapter 3, Gas Transmission Pipeline Modernization Update, and Chapter 4, Valve Automation Program, provides descriptions of all planned PSEP ILI and valve projects that have been and will be performed in compliance with D.11-06-017.

Table 13-2 provides a reference for the specific data points requested in Question 13 to their corresponding column in Table 13-1 of the appendix. Additional data points are included for context in navigating the tables.

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28 Table 13-1 includes projects that have commenced pre-construction activities, but have not yet mobilized.

TABLE 13-2
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 13-1 COLUMN REFERENCE

Column Name	Description
Line #	Reference number for this report.
PSEP Filing PSRS	PSRS number provided in workpapers supporting PG&E's August 26, 2011 filing.
New PSRS	PSRS number provided in workpapers supporting PG&E's PSEP Update Application for pipeline replacement or strength test projects commonly resulting from project split or addition.
Project Description	Order Description provided in workpapers supporting PG&E's August 26, 2011 filing for valve automation, ILI, and upgrades for ILI. Order Description provided in workpapers supporting PG&E's October 29, 2013 PSEP Update Application for pipeline replacement and strength testing.
Mobilization Date	Anticipated project start date.
Tie-In Date	Anticipated project finish date.
Job Estimate Amount	Amount budgeted for project after completing project engineering, routing, permitting and construction bids.
Comments	Descriptions of changes to the project, including project additions, accelerations, delays, and cancellations.

14. Additional Projects Not in Original Workpapers

Describe, in detail, projects that PG&E has completed, are work-in-progress, or have yet to start that were not included in the workpapers submitted in R.11-02-019. Explain why these projects have been included in Phase 1 and whether these projects have lowered the priority of other projects identified in proceeding workpapers and, if so, why. Explain how this work complies with D.11-06-017 and PG&E's Decision Tree and provide the Decision Tree outcome identifier associated with each project.

Response

In the tables referenced in PG&E's prior responses to Questions 11-13, PG&E has identified 13 projects that were not included in the workpapers submitted in the August 2011 PSEP filing and were not included in the PSEP Update Application workpapers. PG&E has added a new appendix table, Table 14-1, to specify new projects that were not in the workpapers, which have been completed, are work-in-progress, have yet to start and accepted by PG&E's Change Control Board. In each case, an explanation of why these projects have been included in Phase 1 is provided in the column titled, "Comments." Table 14-2 provides a reference for the specific data points requested in Question 14 to their corresponding column in Table 14-1 of the appendix. Additional data points are included for context in navigating the tables.

PG&E's PSEP Update Application, Workpapers Supporting Chapter 2, Gas Transmission Pipeline Modernization Program Update provides descriptions of how each of the pipeline replacement and strength testing projects listed in Tables 11-1, 12-1 and 13-1 will be performed in compliance with D.11-06-017, including the associated segment-level PSEP Decision Tree outcome identifier.

TABLE 14-2
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 14-1 COLUMN REFERENCE

Column Name	Description
Line #	Reference number for this report.
PSEP Filing PSRS	PSRS number provided in workpapers supporting PG&E's August 26, 2011 filing.
New PSRS	PSRS number provided in workpapers supporting PG&E's PSEP Update Application for pipeline replacement or strength test projects commonly resulting from project split or addition.
Order Number	Financial system of record reference number to track specific costs, e.g., on individual projects.
Project Description	Order Description provided in workpapers supporting PG&E's August 26, 2011 filing for valve automation, ILI, and upgrades for ILI. Order Description provided in workpapers supporting PG&E's October 29, 2013 PSEP Update Application for pipeline replacement and strength testing.
Job Estimate Amount	Amount budgeted for project after completing project engineering, routing, permitting and construction bids.
Comments	Descriptions of changes to the project, including project additions, accelerations, delays, and cancellations.

15. Project Costs > 10% Above Estimate

For completed projects that are 10% or more over estimated costs, provide a detailed explanation why the overrun occurred.

Response

As PG&E progressed from the preliminary work scope and associated estimates and work plans included in its Implementation Plan, it developed more specific work plans and estimates. These refined estimates, or "Job Estimates," are used in this report to represent the budgeted amount by project for a more meaningful comparison to total costs. Table 11-1 of the appendix referenced in the response to Question 11 includes 15 projects that have cost variances equal to or greater than 10 percent of this budgeted amount, on a project-by-project basis. Identification of the cost and schedule impacts that have driven these cost variances are included within the project-by-project risk analysis on Table 19-1 provided in response to Question 19.

In addition, in the response to Question 19, PG&E has summarized the primary cost drivers that have in many cases resulted in significantly higher total actual project costs than the budgeted amount.

16. Pipeline Piggability Status

Provide a list and map of pipelines that are currently piggable, highlighting pipe that was made piggable as a result of projects conducted under the PSEP. Provide the total mileage of transmission pipelines, the total mileage of pipelines that are currently piggable and percentage of the total that is piggable.

Response

As shown in Table 16-1 below, 204.06 miles of transmission pipeline (95.59 miles from Line 300A, 94.62 miles from Line 300B, 7.06 miles from Line 131 and 6.79 miles from Line 132) were made piggable under PSEP from program inception to June 30, 2014.

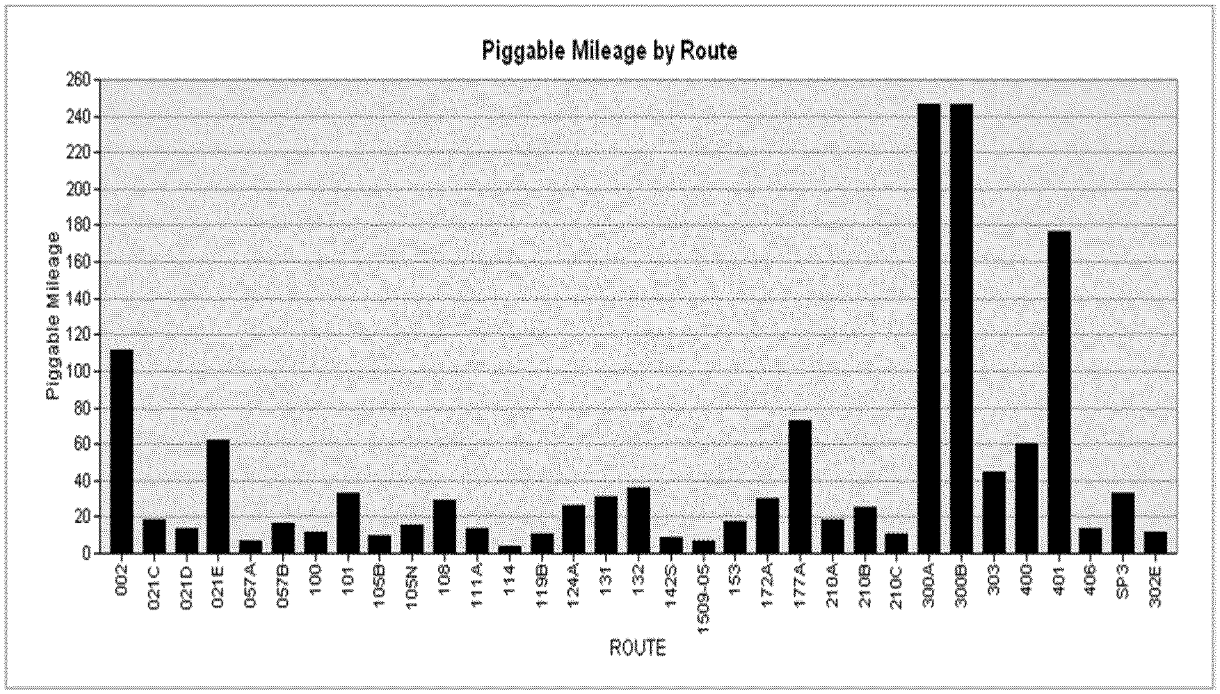
TABLE 16-1
PACIFIC GAS AND ELECTRIC COMPANY
SEGMENTS MADE PIGGABLE UNDER PSEP

Route ID	Launch Mile Point	Receiver Mile Point	Piggable Distance(a)
131	50.57	57.46	7.06
132	31.93	38.40	6.79
300A	299.00	353.80	56.24
300A	354.19	393.53	39.35
300B	299.00	353.80	54.84
300B	354.09	393.61	39.78

(a) Piggable Distance is measured in PG&E's GIS and does not necessarily equal the difference between launch mile point and receiver mile point.

Figure 16-1 shows PG&E's total piggable mileage by transmission pipeline. In total, there are 1498.37 miles of piggable transmission pipeline (see Table 16-2) as of June 30, 2014, which amounts to 22.2 percent of PG&E's approximately 6,750 total transmission pipeline miles. Figure 16-2 provides a map of pipelines that are currently piggable, highlighting pipe that was made piggable as a result of projects conducted under the PSEP.

FIGURE 16-1
PACIFIC GAS AND ELECTRIC COMPANY
PIGGABLE MILEAGE BY TRANSMISSION LINE



SB_GT&S_0339614

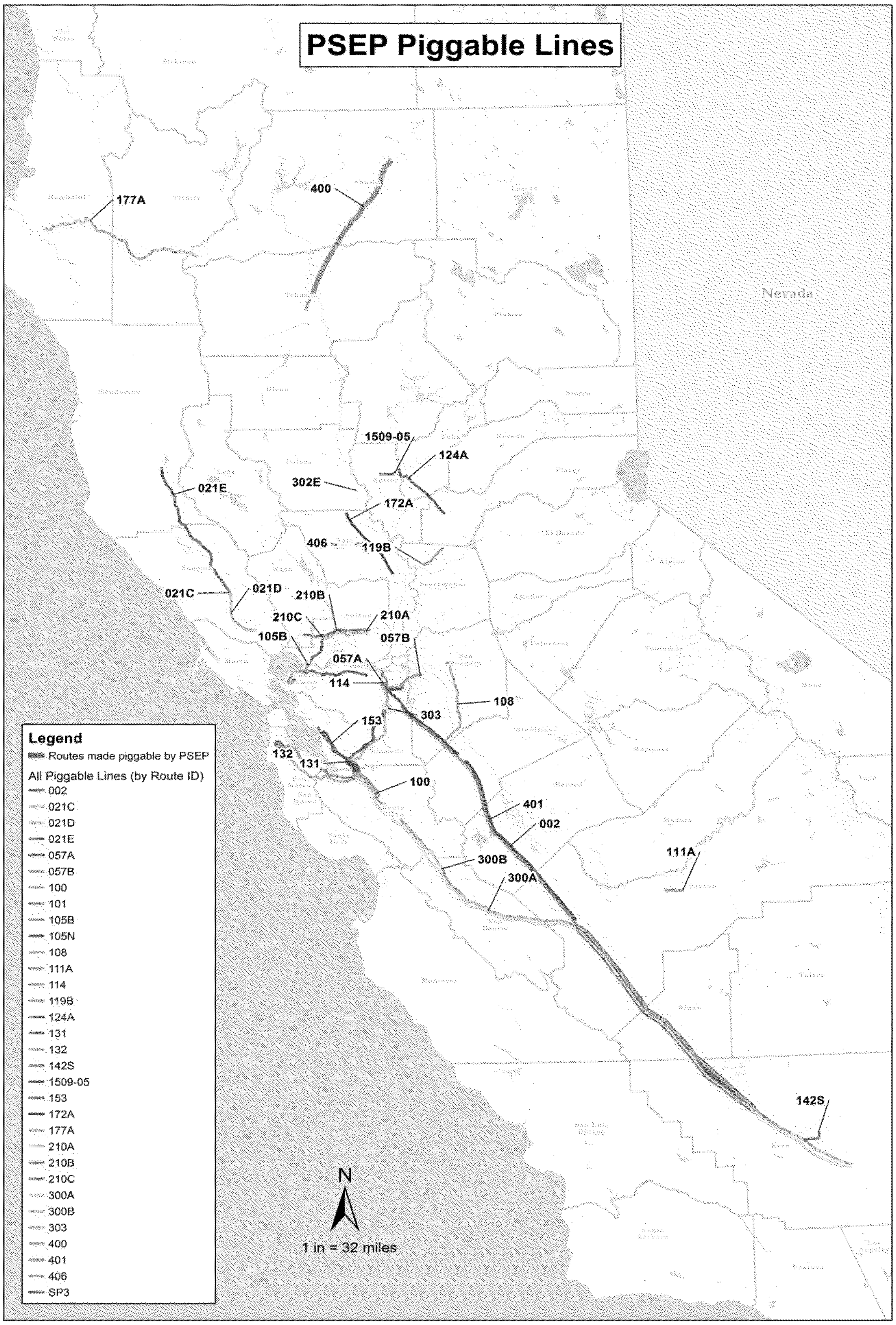
TABLE 16-2
PACIFIC GAS AND ELECTRIC COMPANY
PIGGABLE TRANSMISSION PIPELINE SEGMENTS

Piggable Pipeline Segments			
Route	Launch Mile Point	Receiver Mile Point	Piggable Distance*
002	43.45	118.02	75.28
002	122.06	158.00	36.39
021C	35.05	53.12	18.67
021D	18.64	31.81	13.30
021E	64.54	93.67	30.77
021E	53.12	64.36	11.39
021E	93.67	114.89	20.20
057A	9.49	16.68	7.09
057B	0.00	16.68	16.62
100	138.46	150.13	12.10
101	0.00	11.92	12.36
101	11.62	33.68	21.92
105B	0.02	11.81	11.81
105N	7.76	22.87	16.13
108	0.03	37.15	37.02
111A	20.32	27.58	7.26
114	9.03	16.59	8.02
119B	0.02	10.16	10.40
124A	0.00	26.03	26.42
131	24.89	50.55	26.61
131**	50.57	57.46	7.06
132	0.00	31.93	32.85
132**	31.93	38.40	6.79
142S	0.02	8.98	8.97
1509-05	0.00	6.49	6.45
153	0.00	17.64	17.85
172A	40.08	69.81	29.76
177A	88.83	163.04	74.45
210A	1.38	19.47	18.98
210B	1.39	25.98	25.84
210C	19.47	32.11	12.74
300A	256.21	299.00	43.39
300A**	299.00	353.80	56.24
300A**	354.19	393.53	39.35
300A	393.53	450.83	57.29
300A	450.83	502.24	52.11
300B	393.76	450.79	57.18
300B	450.79	502.64	52.42
300B	256.64	299.00	43.22
300B**	354.09	393.61	39.78
300B**	299.00	353.80	54.84
302E	0.00	12.02	12.02
303	0.00	42.83	44.72
400	82.38	142.60	60.22
401	317.96	427.98	110.04
401	82.34	149.19	67.01
406	0.00	13.80	13.84
SP3	167.31	198.49	33.19
Total			**1498.37**

* Piggable Distance is measured in GIS and does not necessarily equal the difference between launch mile point and receiver mile point.

** PSEP segment.

FIGURE 16-2
PACIFIC GAS AND ELECTRIC COMPANY
MAP OF PIGGABLE PIPELINES



17. Lessons Learned in Phase 1 Work

Describe any lessons learned from undertaking the Phase 1 work that has led to cost efficiencies and quantify any cost savings.

Response

During the current reporting period, PG&E has continued to apply lessons learned and associated process improvements from prior reporting periods, including those previously reported in prior PSEP Compliance Reports. PSEP workstreams remain focused on completing planned work along with implementing cost reduction initiatives. As most of the 2014 projects are still under construction or have not yet begun construction, a majority of the planned cost savings have not yet been realized.

Identified below are lessons learned and associated cost savings during the current reporting period:

<u>Nitrogen Strength Test</u>: Strength testing using nitrogen—as opposed to water—is an approved testing medium and can be particularly cost effective due to location, length of test, or pipe characteristics. Nitrogen testing was conducted on six strength test projects and avoided costs of approximately $3.8 million which would otherwise have been spent on water tank staging, cleaning and filling procedures, water filtration and disposal, as well as additional traffic control and construction measures.

<u>Construction of above ground valve lot</u>: Reached agreement with the city of Suisun on constructing an above ground valve lot on valve project (V-065). Reducing below ground construction significantly reduces the extent of planned excavations and related shoring requirements. Additionally reducing below ground construction has the potential to save approximately $1.5 million.

As reported earlier, PSEP workstreams completed the assessment of lessons learned and identified potential additional process improvements for implementation within the 2014 project portfolio. Leveraging our PSEP experience, listed below are additional examples of initiatives commenced during the first quarter, which if successful, may realize cost savings in 2014:

- Implementing consistent use of Ground Penetrating Radar.
- Broadening use of Shallow Horizontal Dimensional Drilling in urban areas.
- Expanding use of mixed-in-place Controlled Density Fill in lieu of importing fill for backfilling pipelines under pavement areas.

- Expanding use of foam pillows in lieu of sand bags for pipe bedding, reducing installation costs and injury risks.
- Evaluating reuse of clean soil as backfill material. PG&E's Environmental and Gas Construction team is partnering as a cross-functional team to evaluate Best Management Practices and regulatory requirements to implement, process and reuse clean soil as backfill material.

18. Potential Enhancements to Phase 2 Planning and Budgeting

How will the work PG&E conducts in Phase 1 influence how PG&E will plan and estimate the costs of its proposed projects for Phase 2?

Response

Consistent with our response in prior PSEP Compliance Reports, the work PG&E conducts in Phase 1 will directly influence how PG&E will plan and estimate the costs of proposed future pipeline safety work. This is reflected in PG&E's 2015 Gas Transmission and Storage (GT&S) Rate Case Application (A.13-12-012), filed on December 19, 2013 for the period of 2015-2017. Beginning January 1, 2015, PG&E is not forecasting PSEP work separately from other GT&S work.

In PSEP, PG&E selected and prioritized the work using the PSEP Decision Trees approved by the Commission in D.12-12-030. The focus was on enhancing the pipeline integrity in segments that had not previously been subjected to a pressure test. The work was prioritized based on location of pipeline segments in High Consequence Areas (HCA) and Class 3 and 4 locations that were operating at a Specified Minimum Yield Strength of 30 percent or greater.

This served as a good foundation to manage the potential risk by pipeline segments that had not previously been subjected to pressure testing. As demonstrated in the mitigation plans set forth in PG&E's 2015 GT&S Rate Case, PG&E is moving towards a more holistic approach to prioritizing the management of risk arising from the threats to its transmission pipe assets.

PG&E has incorporated available actual cost information, lessons learned and identified efficiencies gained during the PSEP program to develop the mitigation programs, work activities and cost forecasts in the Gas Transmission and Storage Rate Case within the forecast reflected in A.13-12-012.

These lessons learned and the transition from PSEP to the current mitigation programs, are discussed in Chapter 4 of PG&E's GT&S Rate Case and reflected, as applicable, in the specific mitigation programs in Chapter 4A of PG&E's December 19, 2013 Prepared Testimony.[29]

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[29] PG&E 2015 Gas Transmission and Storage Rate Case (A.13-12-012) Prepared Testimony, Volume 1 of 2, Chapter 4: Asset Family – Transmission Pipe, Sections C2b and D; Chapter 4A: Transmission Pipe Integrity and Emergency Response Programs, Sections C and D.

19. Cost Impacts of Unexpected or Unforeseen Items

What, if any, significant unexpected or unforeseen items did PG&E encounter in undertaking the projects and what were the resulting cost impacts on a project-by-project basis?

Response

Table 19-1 of the appendix provides PG&E's most recent risk management assessment with a project-by-project analysis of unexpected or unforeseen items that have affected 2014 completed projects and the resulting cost and schedule impacts,[30] and identifies ways in which PG&E is addressing these risks on an ongoing basis by incorporating the lessons learned into project delivery processes.

For projects completed in the second quarter 2014, PG&E identified that "Changes After Issue for Bid" (IFB)[31] and "Ground Water"[32] caused the greatest cost increases totaling approximately \$2.21 million and \$2.31 million, respectively. "Unexpected condition of pipe, valves or fittings"[33] and "Clearance"[34] accounted for the greatest number of schedule day delays totaling 231 days and 186 days, respectively.

This report identifies the following main risk areas (with associated impacts) with recommendations:

- **Ground Water (Cost and Schedule)**
  - Results: While PG&E makes efforts to identify groundwater conditions and plan accordingly prior to the start of construction, it is difficult to fully determine the volume and flow of groundwater. Two projects,

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30 Impacts are determined using baseline schedule and forecasts after completion of Job Estimate and prior to construction commencement.

31 Any changes to the project scope that were excluded from or occurred after IFB (e.g., additional sniff holes, expanded excavation, added replacement/test length, etc.).

32 A high water table encountered resulting in unplanned dewatering costs and delays in construction.

33 Pipe, valves or fittings may be leaking or faulty requiring additional work to repair or replace them, not including linear indications on the pipe.

34 Tight clearance windows may result in contractor working additional hours to meet the window for tie-in. Delays may also be experienced if a clearance window cannot be obtained when needed due to a variety of reasons. Also, additional labor and/or materials may be necessary to complete clearance.

one strength test and one pipeline replacement project, experienced impacts related to groundwater during the reporting period.

– Recommendations: Continue excavating bell holes, using historical data and researching areas to identify where shallow groundwater conditions may be encountered. Also continue to include costs in the Job Estimate, for handling such conditions.

- **Changes After IFB (Cost and Schedule)**
  - Results: The identification of the common causes of changes that affected projects completed, continues to be used to inform planning activities for 2014 projects.
  - Recommendations: Continue monitoring of this risk within project risk registers along with earlier commencement of pre-construction activities in coordination with Construction Management and Alliance contractors.
- **Unexpected Conditions of Pipe, Valves, or Fittings[35] (Schedule)**
  - Results: Impacts related to this risk varied from conditions such as pipe laminations (i.e., imperfections in pipe wall material) and other similar anomalies in pipe walls and coatings. This risk and the manner in which it may materialize and impact a specific project is being identified as part of planning activities that also incorporate the local knowledge of gas transmission personnel (e.g., the recognition that there is a potential for pipe leaks during a specific strength test due to a history of agricultural land use and prior instances of damage from farming equipment on the pipeline). However, the exact timing, location and extent of impact are highly variable and have the potential to materially impact project cost and schedules (e.g., it may take several weeks and significant resources to remediate pipe laminations).
  - Recommendations: Continue monitoring this risk using project risk registers for projects on the same line, in close proximity, or with similar pipeline attributes (e.g., shallow pipe). Continue to carry forward lessons learned to improve the efficiency of response to future line damage or leaks (e.g., determining damage/leak location).

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35 Pipe, valves, or fittings may be leaking or faulty, requiring additional work to repair or to replace them. This category does not include linear indications on the pipe, the occurrence of which are tracked in a separate category.

TABLE 19-2
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 19-1 COLUMN REFERENCE

Column Name	Description
Line #	Reference number for this report.
New PSRS	New PSRS number resulting from project split or addition.
Project Description	Order Description provided in workpapers supporting PG&E's August 26, 2011 filing for valve automation, ILI, and upgrades for ILI. Order Description provided in workpapers supporting PG&E's PSEP October 29, 2013 Update Application for pipeline replacement and strength testing.
Region	Region where line is located.
Risk	Categorization of risk factor affecting the project.
Description	Description of risk factor.
Cost Impact ($)	Impact of risk to project cost.
Schedule Impact (Days)	Impact of risk to schedule in number of days.
>10% Variance	Projects greater than 10 percent over Job Estimate.
Comments	Description of how risk factor materialized.

20. Program Amount Authorized and Spent

Provide a table showing the total amount authorized for recovery from ratepayers and the total amount spent by PG&E year-to-date shown by month and broken down activity (e.g., hydrotesting, pipe replacement).

Response

Table 20-1, in the appendix, shows the total amount spent by PG&E in the current reporting period and YTD, shown by month and broken down by activity. Amounts authorized for customer recovery based on D.12-12-030 is provided at the program activity level, consistent with the presentation in Attachment E of D.12-12-030. PG&E also provides in Table 20-1, the amounts requested for recovery in the PSEP Update Application (A.13-10-017), at the program activity level, because the PSEP Update Application represents a reduced amount for recovery by ratepayers from the amounts approved in D.12-12-030.

21. Shareholder Costs Absorbed

Provide a table showing the total amount of costs that shareholders will absorb year-to-date shown by month and broken down activity (e.g., hydrotesting, pipe replacement).

Response

Table 20-1, included in response to Question 20, provides the total amount of costs that shareholders have absorbed in the current reporting period and YTD, shown by month and broken down by activity. Amounts funded by shareholders have been calculated using the amounts requested for recovery in the PSEP Update Application (A.13-10-017), at the program activity level, because the PSEP Update Application represents a reduced amount for recovery by ratepayers from the amounts approved in D.12-12-030.

From a financial reporting perspective, PG&E is required to record substantial increases to shareholders' loss when it is probable and estimable. Although the PSEP Update Application has not been authorized by the CPUC, PG&E does not believe it is probable that the costs will be recoverable in excess of amounts it has proposed therein. Therefore, the October 2013 Update Application has been used to determine the shareholder-funded portion of PSEP costs.

22. Forecast vs. Actual Mileage – Replacements

Provide a table showing the total mileage of pipe PG&E forecast to replace in R.11-02-019 and the mileage PG&E has replaced year-to-date. Identify the location, Line #, milepost, Class of the pipe replaced. Indicate whether the pipe is located in a High Consequence Area.

Response

As of June 30, 2014, PG&E has replaced, retired and downrated approximately 108 miles of gas transmission pipeline as part of the PSEP program. Table 22-1 below provides the total pipeline miles PG&E forecast to replace, retire and downrate in R.11-02-019 (i.e., PG&E's August 2011 Implementation Plan) and the total pipeline miles replaced, retired and downrated year-to-date for 2014. Table 22-2 of the appendix provides detail on 29 projects completed (tied-in) in 2014 through the end of this reporting period, identifies the location, pipeline number, milepost, and class of the pipeline section replaced, and indicates whether the pipeline is located in a HCA on a project-by-project basis.

Table 22-3 provides a reference for the specific data points requested in Question 22 to their corresponding columns in Table 22-2 in the appendix. Additional data points are included for context in navigating the tables.

TABLE 22-1
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL PIPELINE MILES REPLACED, RETIRED AND DOWNRATED – FORECAST AND ACTUAL
APRIL 1 – JUNE 30, 2014

Pipeline Replacement	2014
Forecast R.11-02-019	82.40
Actual Replaced, Retired, Downrate and Tied-in(a)	1.41
Actual Replaced	1.36
Actual Retired	0.04
Actual Downrate	0.00
Actual Installed Pending Tie-In	2.67
Total Actual	4.08

(a) Mileage reflects pipeline lengths identified in August 26, 2011 PSEP filing and is subject to final engineering review of as-built drawings to validate segment-level completion of PSEP scope. Forecast may adjust in the future pending the outcome of PG&E's PSEP Update Application filed on October 29, 2013.

TABLE 22-3
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 22-2 COLUMN REFERENCE

Column Name	Description
Line #	Reference number for this report.
PSEP Filing PSRS	PSRS number provided in workpapers supporting PG&E's August 26, 2011 filing.
New PSRS	PSRS number provided in workpapers supporting PG&E's PSEP Update Application for pipeline replacement or strength test projects commonly resulting from project split or addition.
Project Description	Order Description provided in workpapers supporting PG&E's August 26, 2011 filing for valve automation, ILI, and upgrades for ILI. Order Description provided in workpapers supporting PG&E's October 29, 2013 PSEP Update Application for pipeline replacement and strength testing.
Miles Completed	Miles of pipeline replaced, retired, downrated or tested.
Installed	Replaced Miles.
Retired	Pipeline removed from service.
Downrated	Lowered pipeline operating pressure to 60 pounds per square inch gauge (psig) or less.
Line	Pipeline identifier.
MP1	Beginning project mile point.
MP2	Ending project mile point.
City	Location of project.
HCA	Project includes a High Consequence Area.
Class Code	Class of pipeline included in project.
Clearance Date	Date pipe was cleared and work authorized to begin.
Tie-In Date	Date pipe became operational and project completed.

23. Forecast vs. Actual Mileage – Strength Testing

Provide a table showing the mileage of pipe PG&E forecast to hydrotest in R.11-02-019 and the mileage PG&E has tested year-to-date. Identify the location, Line #, milepost, Class of the pipe tested. Indicate whether the pipe is located in a High Consequence Area.

Response

As of June 30, 2014, PG&E has completed strength testing on over 566 miles of gas transmission pipeline since the inception of the PSEP program, in addition to the validation of the records of approximately 158 miles of prior strength tests as meeting the "traceable, verifiable and complete" standard. Table 23-1 below, provides the total pipeline miles PG&E forecast to strength test in R.11-02-019 (PG&E's August 2011 Implementation Plan) and the total strength tested through the end of this reporting period. Table 23-2 of the appendix provides detail on 26 completed projects, identifies the location, pipeline number, milepost, and class of the pipe tested, and indicates whether the pipe is located in a HCA on a project-by-project basis.

Table 23-3 provides a reference for the specific data points requested in Question 23 to their corresponding columns in Table 23-2 in the appendix. Additional data points are included for context in navigating the tables.

TABLE 23-1
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL PIPELINE MILES STRENGTH TESTED – FORECAST AND ACTUAL
APRIL 1, 2011 – JUNE 30, 2014

Pipeline Strength Testing	2011	2012	2013	2014
Forecast R.11-02-019	236.0	185.0	204.0	158.0
Actual Tested and Tied-in(a)(b)	163.6	176.2	198.8	27.4
Actual Records Validated(c)	50.9	27.8	39.7	39.7
Total Actual	214.5	204.0	238.5	67.1

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(a) Mileage reflects pipeline lengths identified in August 26, 2011 PSEP filing and is subject to final engineering review of "as-built" drawings to validate segment-level completion of PSEP scope. Forecast may adjust in the future pending the outcome of PG&E's PSEP Update Application filed on October 29, 2013.

(b) Includes 2.6 miles in 2011, 36.3 miles in 2012 and 12.2 miles in 2013 of segments for which costs will not be included within PSEP costs.

(c) Includes pipeline miles for which records of a prior strength test were validated as meeting the traceable, verifiable and complete records standard.

TABLE 23-3
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 23-2 COLUMN REFERENCE

Column Name	Description
Line #	Reference number for this report.
PSEP Filing PSRS	PSRS number provided in workpapers supporting PG&E's August 26, 2011 filing.
New PSRS	PSRS number provided in workpapers supporting PG&E Update Application for pipeline replacement or strength test projects commonly resulting from project split or addition.
Project Description	Order Description provided in workpapers supporting PG&E's August 26, 2011 filing for valve automation, ILI, and upgrades for ILI. Order Description provided in workpapers supporting PG&E's October 29, 2013 Update Application for pipeline replacement and strength testing.
Miles Completed	Miles of pipeline replaced, retired, downrated or tested.
Line	Pipeline identifier.
MP1	Beginning project mile point.
MP2	Ending project mile point.
City	Location of project.
HCA	Project includes a High Consequence Area.
Class Code	Class of pipeline included in project.
Clearance Date	Date pipe was cleared and work authorized to begin.
Tie-In Date	Date pipe became operational and project completed.

24. Public Outreach Costs

Provide the costs of the public outreach PG&E has incurred year-to-date by month as compared to the amount authorized. Explain in detail what public outreach activities PG&E has engaged in.

Response

Customer Outreach is included as an integral part of each PSEP construction project. Customer and community outreach costs incurred since program inception in 2011 are shown annually for 2011-2014 in Table 24-1. Monthly customer and community outreach costs for 2014 are shown in Table 24-2.

TABLE 24-1
PACIFIC GAS AND ELECTRIC COMPANY
PUBLIC OUTREACH COSTS
APRIL 1, 2011 – JUNE 30, 2014
(IN MILLIONS OF DOLLARS)

2011	2012	2013	2014
$2.62	$4.54	$4.21	$1.89

TABLE 24-2
PACIFIC GAS AND ELECTRIC COMPANY
2014 MONTHLY PUBLIC OUTREACH COSTS
(IN MILLIONS OF DOLLARS)

Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014
$0.17	$0.24	$0.37	$0.39	$0.41	$0.32

D.12-12-030 approved customer outreach costs, including governmental outreach, within individual project estimated costs. PG&E's estimated customer outreach costs varied by workstream driven by the nature of the work and were based upon a percentage of project costs before project management and escalation.

For pipeline replacement and strength testing projects the customer outreach cost estimate was 2.9 percent of estimated construction costs, and for valve automation projects the equivalent was 0.54 percent. Specific monthly authorized amounts cannot be accurately determined from D.12-12-030 due to individual project durations and the timing of activities within projects. Public outreach activities undertaken by PSEP have included the use of Interactive Voice Responses (IVR or automated phone notifications), letters, open houses, signage, door-to-door canvassing, one-on-one customer phone calls and meetings, and customer group presentations. As of June 30, 2014, 14 open houses have been hosted, 130,951 letters have been mailed, and 164,726 IVR calls have been made to customers impacted by PSEP work during 2014.

Customer Outreach activities are managed on a consistent basis across PSEP workstreams by a dedicated team of Customer Impact Specialists within PG&E's Customer Care organization. Each project follows a standardized process for customer outreach which includes, but is not limited to:

- Site walk with project team to identify customer impacts.
- Letter to impacted customers.
- Invitation to an open house hosted by PG&E within the affected project area.
- Work location signage prior to mobilization.
- IVR sent to area customers prior to significant activities (e.g., venting/release of natural gas).
- Additional customer outreach and accommodations as dictated by the nature of the project (e.g., temporary relocation for nitrogen strength test).
- Local customer canvassing to identify and incorporate feedback into ongoing procedures.

In an effort to increase open house attendance, the Customer Outreach team sent out an IVR reminder and/or canvassed an impacted area, inviting customers to attend the open house in their area. The IVR reminded customers of the date, time, and location of the open house. Canvassing visits involved leaving behind door hangers that included copies of the letter with an open house invitation that these customers had already received. During the current reporting period, the Customer Impact team has continued to utilize IVRs to remind customers of the date, time, and location of a local open house, along with canvassing visits leaving behind door hangers that include copies of the open house invitation which has helped maintain open house attendance at an average of nine attendees per open house.

Customer Impact inserts additional customer touch points where deemed beneficial, depending on the particular situation. During the current reporting period, Customer Impact partnered with local homeowners associations on

Projects R-167 and R-185 to present project information at the area homeowners association meeting. In addition to the presentations Customer Impact worked with the homeowners associations to have project information and construction updates communicated to residents via the community email distribution list. These projects run through densely populated residential and commercial areas where additional customer communication and outreach is required to identify and address customer concerns. Given the proximity to local businesses and residences of the project area affected by R-185 Customer Impact has worked with the homeowners association to send venting notifications via email in addition to the regular IVR notifications to increase awareness of construction activity. In total, 2,098 residents affected by these projects have received project information and updates via homeowners association email in addition to receiving project information by letter and IVR directly from PG&E.

In addition to partnering with homeowners associations, Customer Impact identifies alternate means of communicating with affected customers when regular outreach tactics are not feasible. For example, in situations where construction activity impacts military installations, regular communication tactics such as letters and IVRs are not feasible due to a lack of individual customer data. During the current reporting period, Customer Impact supported T-358 which impacted China Lake Naval Weapons Station. Customer Impact worked with Energy Solutions and Service representatives and the Naval Station to communicate project information to base employees though email communication rather than a letter and IVR. In total approximately 1,200 base personnel received emails regarding project information.

25. Service Outage Performance

Describe (e.g., provide date(s), location, Line #) all planned and unplanned service outages PG&E experienced in conducting the project work and explain how PG&E addressed customer needs during the outages. Were customers notified of any outages beforehand?

Response

PG&E has successfully conducted gas transmission pipeline outages supporting 72 completed construction projects in 2014, with minimal impact to customer service. Tables 22-2 and 23-2 provide pipeline clearance dates, tie-in dates,[36] locations, and pipeline numbers, on a project-by-project basis for 29 completed pipe replacements and 26 strength test projects.

Table 25-1 of the appendix supplements these tables by providing information for 11 completed valve automation, and 6 ILI projects in 2014. Table 25-2 provides a reference for the specific data points requested in Question 25 to their corresponding column in Table 25-1 in the appendix. Additional data points are included for context in navigating the tables.

[36] The days between the clearance date and the tie-in date provides the number of pipeline outage days.

TABLE 25-2
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 25-1 COLUMN REFERENCE

Column Name	Description
Line #	Reference number for this report.
PSEP Filing PSRS	PSRS number provided in workpapers supporting PG&E's August 26, 2011 filing.
New PSRS	PSRS number provided in workpapers supporting PG&E's PSEP Update Application for pipeline replacement or strength test projects commonly resulting from project split or addition.
Project Description	Order Description provided in workpapers supporting PG&E's August 26, 2011 filing for valve automation, ILI, and upgrades for ILI. Order Description provided in workpapers supporting PG&E's October 29, 2013 PSEP Update Application for pipeline replacement and strength testing.
Miles Completed/Valves Automated	Miles of pipeline replaced or tested; Number of valves automated.
Line	Pipeline identifier.
MP1	Beginning project mile point.
MP2	Ending project mile point.
City	Location of project.
HCA	Project includes a High Consequence Area.
Class Code	Class of pipeline included in project.
Clearance Date	Date pipe was cleared and work authorized to begin.
Tie-In Date(a)	For ILI and pipeline testing and replacement projects, the tie-in date is the date the pipe became operational and the project was completed. For valve automation projects, the tie-in date is the date the date the pipeline is "commissioned" (released to gas control).

(a) The definition differs slightly from Table 25-2 in PG&E's PSEP Compliance Report No. 2013-01 for 2011-2012 valve automation projects.

As previously mentioned, initial project design and planning activities include identification of potential customer impacts. PG&E specifically works to minimize the impact to customers and schedules work where possible to avoid customer outages by using existing system redundancies (e.g., cross compression, parallel pipes, or back-feeds to maintain customer service). This is a primary reason why many construction activities cannot take place during seasonal winter gas demand periods.

To mitigate potential customer impact, PG&E increased its LNG/CNG portable program to enable the increased avoidance of customer outages. Rising from 22 units in 2010 to 202 units targeted in 2014, the program continues to be an integral part of project planning and scheduling activities and has successfully met the significantly increasing demand for its services. The program has supported 1,159 tap days and 575,497 customer days in the second quarter of 2014 using portable CNG and LNG equipment. Further, the LNG/CNG program supported the entire community of Ridgecrest and the China Lake Naval Weapons Station for 10 days using portable LNG and CNG equipment during the T-358 strength test.

In cases where customer loads are significant, PG&E has worked with assigned account representatives to schedule activities to minimize impact and potentially avoid the significant costs associated with LNG support operations. This has involved scheduling tests outside of agricultural peak periods and commercial work hours and scheduling project activities to occur outside of school hours or key events.

26. Forecast Projects Not Completed or Replaced

Describe or provide a specific reference to PG&E's work papers of the projects that were not completed or replaced by a higher priority project and show the uncompleted project's associated costs. Compute the corresponding reduction to the Implementation Plan adopted amounts set out in Attachment E, as required by Ordering Paragraph 6.

Response

PG&E's PSEP Update Application presents all pipeline replacement, downrate, retirement and strength testing projects that were not completed or have been cancelled and provides updated costs estimates of all previously authorized and proposed PSEP projects. PG&E's PSEP Update Application shows the corresponding reductions and additions to pipeline replacement and strength testing amounts set out in Attachment E, as required by OP 6.

Table 26-1 of the appendix includes a list of one previously planned 2014 project, with specific reference to prior PG&E work papers, which was not completed or replaced by a higher priority project in this reporting period.[37]

TABLE 26-2
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 26-1 COLUMN REFERENCE

Column Name	Description
Line #	Reference number for this report.
PSEP Filing PSRS	PSRS number provided in workpapers from proceedings.
New PSRS	New PSRS number resulting from project split or addition.
Project Description	Order Description provided in workpapers from proceedings.
PSEP Filing Year	Year project anticipated to begin as stated in the filing.
Current Status	Current project status.
Comments	High-level descriptions for projects that were not completed or replaced.

37 For similar project data related to 2011 and 2012 projects refer to PSEP Compliance Report No. 2013-01.

27. Project Cost Recovery

Provide a clear explanation, for each project for which expenditures have been incurred, of how the project is necessary to comply with PSEP requirements rather than being included among projects that are already funded in D.11-04-031.

Response

The scope of PG&E's PSEP is based upon pipeline segments previously identified as not having been strength tested, and/or without traceable, verifiable and complete records of such a test. The specific actions to be taken under PSEP, and the prioritization of such projects, are based upon the results of consistently applying a sequential decision process (PSEP Decision Tree) to pipeline segment features information. PG&E's original PSEP scope was based upon pipeline data as of January 2011 and PG&E anticipated that the update and completion of the review of pipeline segment information would alter the scope of PSEP's projects. During the PSEP proceeding, PG&E confirmed that the PSEP scope as filed excluded any pipeline segments previously included within other recovery mechanisms, including projects approved as part of the Gas Accord V Settlement in D.11-04-031.

To the extent that additional scope has been added to a PSEP project that does not meet the PSEP Decision Tree criteria (or it is a non-adjacent non-HCA, Class 1 or 2 pipe segments) PG&E has identified and is separately tracking costs associated with this increased project scope. Examples would include, an increase in pipeline diameter to support future capacity needs or a project identified in D.11-04-031 that is engineered, permitted and constructed with an adjacent PSEP project to capture efficiencies.

PG&E's August 26, 2011 PSEP filing, Workpapers Supporting Chapter 3, Gas Transmission Pipeline Modernization Update, and Chapter 4, Valve Automation Program provides descriptions of all planned PSEP ILI and valve projects that have been and will be performed in compliance with D.11-06-017, including the associated segment-level Decision Tree outcome identifier where applicable. PG&E's October 29, 2013 PSEP Update Application, Workpapers Supporting Chapter 2, Gas Transmission Pipeline Modernization Program Update provides descriptions of all planned PSEP pipeline replacement and strength test projects which have been and will be performed in compliance with D.11-06-017, including the associated segment-level Decision Tree outcome identifier.

28. Record Improvement Efforts Progress

Progress report on record improvement efforts, including report on costs absorbed by shareholders.

Response

PG&E's Mariner Project (formerly referred to as the "GTAM Project"), is part of the Pipeline Records Integration Program proposed in the PSEP filing (R.11-02-019). Mariner costs are included in Table 20-1 and are completely funded by shareholders in compliance with D.12-12-030. The goal of the Mariner Project is to further enhance the safety and reliability of PG&E's gas transmission system through increased access to pipeline systems data, integrated risk management and integrity management analytics, and improved work management. Specifically, the Mariner Project will:

- Improve data availability by eliminating paper-based work processes and installing tools to enable the electronic collection, processing, review, analysis, and integration of pipeline systems data.
- Improve PG&E's pipeline risk management capabilities by integrating different types of asset data into a single system.
- Support PG&E's PSEP and address the CPUC and National Transportation Safety Board concerns by enabling and supporting asset data that are traceable, verifiable and complete.
- Generate operational efficiencies related to the time required to: (1) enter and upload data into the system; (2) locate and collect information maintained in different offices and different records management systems; and (3) correlate and analyze engineering data, and associated with field force dispatch (as work assignments can be automated and optimized to minimize travel). Full realization of benefits is dependent on the integration of the various components of the Mariner Project.

The Mariner project made progress in several functional areas by providing new mobile devices to field personnel, replacing outdated hardware, providing access to electronic maps, deploying integrated risk management tools, and converting records into electronic formats. The Mariner Project is also progressing toward integrating work management and asset systems, and mobilizing corrective and preventative maintenance processes.

In PG&E's August 26, 2011 prepared testimony, PG&E described four phases of project development.[38] This report lists the activities that were included in each phase and provides a summary of the activities completed as of June 30, 2014. During October and November 2013, PG&E evaluated the Mariner Project and modified some of its management structure. Most of these changes involve modifying the management structure of the various Mariner initiatives, combining smaller projects into larger initiatives for improved oversight, and revising the schedule of some of the project components. In particular, the completion date for some of the asset maintenance and material traceability work has been extended from the first quarter 2015 to the end of 2015.

The following section details work and progress to date by each functional area affected by the Mariner Project in the current reporting period. Please see PSEP Compliance Reports Nos. 2013-02, 2013-03, 2013-04 and 2014-01 for progress made by each functional area prior to this reporting period.

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38 Please refer to PSEP Compliance Report No. 2013-02 for a description of the Mariner Project's four phases.

<table>
<tr><th>Functional Area</th><th>Work Completed in Q2 (April 1 – June 30, 2014)</th><th>Mariner Project Phases</th></tr>
<tr><td>Leak Survey</td><td>Work within this functional area is now complete.(a)</td><td>Phases 0 and 1</td></tr>
<tr><td>Locate and Mark</td><td>Work within this functional area is now complete.(a)</td><td>Phase 0</td></tr>
<tr><td>Corrective Maintenance</td><td><u>Project Description</u>
This effort provides for an accurate and complete dataset of information recorded in the Integrated Gas Information System (IGIS) and other corrective maintenance history to be included in SAP.
<u>Progress and Accomplishments</u>
Completed pilot for gradable leaks and other corrective work for Local Transmission and Distribution (LTD) assets, in the Peninsula and Stockton divisions, in March 2014 and planned deployment in other divisions.
Began phased deployment for LTD assets in Fresno, Yosemite, and Kern divisions in May 2014.
Began phased deployment for LTD assets in San Francisco, Central Coast, and DeAnza divisions in June 2014.
Completed planning and analysis to migrate backbone and station assets from various systems to SAP and to automate and digitize corrective maintenance on these assets using SAP and mobile technology.</td><td>Phases 0 and 1</td></tr>
<tr><td>Records Management</td><td>Work continues within this functional area. No major milestones reached within this reporting period.</td><td>Phase 1</td></tr>
<tr><td>Mobile Technology Foundation</td><td>Work within this functional area is now complete.(a)</td><td>Phase 2</td></tr>
<tr><td>Preventive Maintenance</td><td><u>Project Description</u>
Paperless process for documenting preventative maintenance work performed in the field.
<u>Progress and Accomplishments</u>
Completed pilot for Preventive Maintenance mobile application for LTD assets in the Peninsula and Stockton divisions in March 2014.
Began phased deployment for LTD assets in Fresno, Yosemite, and Kern divisions in May 2014.
Began phased deployment for LTD assets in San Francisco, Central Coast, and DeAnza divisions in June 2014.
Completing planning and analysis to migrate backbone and station assets from various systems to SAP and to automate and digitize preventive maintenance on these assets using SAP and mobile technology.</td><td>Phase 2</td></tr>
<tr><td>GIS</td><td><u>Project Description</u>
Deployment of new Gas Transmission (GT) GIS system using data from the MAOP project that uses Linear Asset Management and is integrated with SAP.
<u>Progress and Accomplishments</u>
Continued validating asset data from multiple sources (i.e., the Pipeline Open Data Standard (PODS) database, Pipeline Centerline Survey, and Spatial Alignment) to be included in GT GIS.
Continued to gather business and technical requirements to integrate Intrepid asset management solution, SAP-Linear Asset Management, SAP-GEO and Documentum.
Designed the solution for GT GIS system integration and data conversion and began building the solution.</td><td>Phases 1, 2 and 3</td></tr>
</table>

Functional Area	Work Completed in Q2 (April 1 – June 30, 2014)	Mariner Project Phases
Integrity Management	**Project Description** Implement industry standard "best practice" technology solutions to automate manual integrity analysis tasks and integrate tools with core enterprise systems. **Progress and Accomplishments** • Launched class location, HCA and risk analysis tools. • Designed the solution to repoint tools to certified GIS data and began building the solution.	Phase 1
Material Traceability	Work within this functional area is scheduled to begin in the third quarter 2014 and to be completed in 2015.	Phases 0 and 1
Project & Portfolio Management	**Project Description** Implement an SAP-specific portfolio and project management (PPM) solution that: 1) Consolidates multiple PPM processes into one system. 2) Enables enhanced project controls, governance, documentation, and versioning. 3) Improves alignment and reporting between high-level budgets and individual projects. 4) Integrates with S2 planning process. **Progress and Accomplishments** Developed cost estimate and high-level requirements	Phase 3

(a) Major milestones were completed in Quarter 2 of 2013. Please refer to PSEP Compliance Report No. 2013-02 for additional details.

29. Additional Relevant Information

Any additional relevant information not listed above as specified in hearing Exh. 2 at 8E-1 and 8E-2.

Response

PG&E considers that the information provided within this report covers all aspects previously outlined in *hearing Exh. 2 at 8E-1 and 8E-2.*

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX

TABLE 1-1
PACIFIC GAS AND ELECTRIC COMPANY
PROJECT STATUS SUMMARY - PROJECTS AT RISK OF NON-COMPLETION IN 2014
REPORTING PERIOD APRIL 1, 2014 – JUNE 30, 2014

Line #	New PSRS	Probability of Delay Past 2014 (a)	Project Description	City	Mobilization Date (b)	Tie-in Date/Operative Date (b)	Job Miles/Valves at Risk	Drivers for Potential Project Delays
1	23972	High	V-044 Valve Auto - Sheridan Rd	Sunol	7/31/2014	11/8/2014	4 valves	Timing of receipt of SF planning environmental permit uncertain; series of clearances required to complete construction.
2	24026	Medium	I-062 L-132	Burlingame	9/11/2014	9/20/2014	6.70	Pressure restoration may be required; timing of receipt of SFPUC permit uncertain.
3	23815	Medium	R-010 L-108_2	Thorton	4/1/2014	12/15/2014	0.14	New pipeline has been installed and buried. Tie-in has been delayed to be combined with an adjacent GT&S base-funded pipeline replacement project for a class location increase.
4	24900	Medium	R-016 L-108_3	Sacramento	8/18/2014	10/31/2014	1.14	Anticipated that land easement will require use of eminent domain.
5	26023	Medium	R-046 L-109_4A_1	Redwood City	9/20/2014	12/27/2014	1.90	Application of air quality limits across concurrent projects by San Francisco Public Utilities Commission (SFPUC) may result in extension of construction duration.
6	26025	Medium	R-048 L-109_4C	Hillsborough	8/1/2014	10/30/2014	1.26	Permitting delay - Planning Department of City and County of San Francisco (SF Planning).
7	28468	Medium	R-059 L-123	Roseville	5/9/2014	10/15/2014	0.13	Timing of receipt of environmental permit from California Department of Fish and Wildlife uncertain.
8	30616	Medium	R-167 L-123	Roseville	7/14/2014	10/16/2014	0.71	Timing of receipt of environmental permit from United States Army Corps of Engineers (USACE) uncertain.
9	30667	Medium	R-185 L-109_4A_2	San Mateo	8/8/2014	10/18/2014	1.04	Application of air quality limits across concurrent projects by San Francisco Public Utilities Commission (SFPUC) may result in extension of construction duration.
10	27018	N/A	R-052 L-109_3C	Redwood City	2015	2015	0.79	Original pipeline route rejected, conducting new environmental impact (EIR). Construction rescheduled to 2015
11	31042	N/A	R-188 L-220	Davis	2015	2015	0.52	Unable to obtain easement on preferred (shortest) route. Developing new alignment. As a result, construction rescheduled to 2015.
12	32307	N/A	R-240 L-109_4A_3	San Mateo	2015	2015	0.51	Identification of poor soil conditions preclude preferred construction method (Horizontal Directional Drilling, or HDD); new alignment and construction method require environmental impact (EIR) report.

(a) Probability that the current risk materializes and pushes the schedule to after December 31, 2014. The response "N/A" indicates the risk has materialized and the project will be completed after December 31, 2014.
(b) Mobilization Date and Tie-in Date are based on most current information available.

TABLE 11-1
PACIFIC GAS AND ELECTRIC COMPANY
PROJECT STATUS SUMMARY - PROJECTS COMPLETED
JANUARY 1, 2014 – JUNE 30, 2014

Line #	PSEP Filing PSRS	New PSRS	Order Number	Project Description	City	Construction Contractor	Mobilization Date	Tie-in Date	Job Estimate Amount	Total Cost	Labor Cost	Materials Cost	Contracts Cost	Other Cost	Variance to Budget	PSEP Disallowed Cost	Non-PSEP costs	>10% Over Budget	Comments
1	23867	26041	30842240	R-056 L-220 4.93MI MP 20.84-31.65 REPL PH1 (partial retirement)	Davis	Barnard	22-Jul-13	10-Jan-14	$ 37,500,000	$ 35,642,139.43	$ 1,840,774.33	$ 1,143,602.26	$ 30,201,743.41	$ 2,456,019.43	$ (1,857,860.57)	$ 34,045.52	$ -	No	Delayed from 2013 to 2014 due to Constructability/Efficiency reasons
2	24009	24009	30847124	I-001 L-131 MP 50.5-57.4 Upgrade PH1	Fremont	GT/GC	14-Feb-13	15-Jan-14	$ 10,084,783.00	$ 10,236,117.39	$ 2,964,593.75	$ 1,641,832.06	$ 3,887,864.39	$ 1,741,827.19	$ 151,334.39	$ -	$ -	No	Delayed from 2012 to 2013 due to workspace limitations at Milpitas Station and resource constraints across PSEP work.
3	23776	31978	31031894	RT-029 DREG5483-NV REPL PH1	Redding	GT/GC	8-Jan-14	21-Jan-14	$ 522,437.00	$ 330,161.47	$ 229,569.46	$ 17,558.92	$ 137,110.70	$ (54,077.61)	$ (192,275.53)	$ 148,111.25	$ -	No	Project addresses partial scope of originally filed TAPS project.
4	23749	31970	31031729	RT-022 DREG4873-MI REPL PH1	San Leandro	GT/GC	15-Jan-14	24-Jan-14	$ 313,907.00	$ 127,027.34	$ 159,895.48	$ 8,086.91	$ 21,268.16	$ (62,223.21)	$ (186,879.66)	$ 88,206.31	$ -	No	Project addresses partial scope of originally filed TAPS project.
5	23787	32001	31031890	RT-046 STUB6041-SI REPL PH1	Live Oak	GT/GC	23-Jan-14	24-Jan-14	$ 132,066.00	$ 238,163.19	$ 150,942.33	$ 6,334.80	$ 54,291.99	$ 26,594.07	$ 106,097.19	$ -	$ -	Yes	Project addresses partial scope of originally filed TAPS project.
6	23597	23597	30842274	VA-010 Valve Auto - Commercial Way, 3V, PH1	San Carlos	Underground	17-Apr-13	24-Jan-14	$ 4,628,306.00	$ 4,918,467.90	$ 615,893.79	$ 970,188.23	$ 5,225,150.08	$ (1,892,764.20)	$ 290,161.90	$ -	$ -	No	Delayed from 2012 to 2014, due to other clearances taking priority on S.F. peninsula.
7	#N/A	30094	30984493	VA-068A Valve Auto - Airport & Louise, 3V, PH1	Manteca	Snelson	1-Oct-13	27-Jan-14	$ 2,536,322.00	$ 2,722,114.26	$ 512,499.69	$ 356,711.82	$ 1,708,555.67	$ 144,347.08	$ 185,792.26	$ -	$ -	No	Added to replace filed Valve Auto project Airport & Louise(PSRS 23664) for cost and efficiency reasons due to construction complexities at the filed project site.
8	#N/A	29247	30842229	R-037 L-172A 3.06MI MP 75.43-78.53 REPL PH1 (partial retirement)	West Sacramento	Barnard	19-Aug-13	31-Jan-14	$ 43,500,000.18	$ 37,133,865.11	$ 1,469,965.39	$ 1,698,288.70	$ 33,871,918.35	$ 93,692.67	$ (6,366,135.07)	$ 1,778,944.91	$ -	No	-
9	23888	23888	30842216	R-109 L-116 0.04MI MP 0.00-0.03 REPL PH1 (partial retirement)	Davis	GT/GC	5-Aug-13	5-Feb-14	$ 658,425.00	$ 700,906.58	$ 128,704.78	$ -	$ 7,302.15	$ 564,899.65	$ 42,481.58	$ 25,511.20	$ -	No	-
10	23930	23930	30842177	R-111 DFM-0627-01 0.01MI MP 0.00-0.02 REPL PH1	Davis	GT/GC	5-Aug-13	5-Feb-14	$ 360,443.00	$ 335,091.47	$ 75,289.55	$ 22,370.88	$ 30,236.17	$ 207,194.87	$ (25,351.53)	$ 118,339.54	$ -	No	-
11	#N/A	32860	31056343	VA-119 Valve Auto - Davis Meter Reg Station	Sacramento	Barnard	30-Dec-13	5-Feb-14	$ 566,321.00	$ 4,095.65	$ 3,581.75	$ -	$ -	$ 513.90	$ (562,225.35)	$ -	$ -	No	Project added for system isolation between L-220 and L-119A.
12	#N/A	31601	41948620	D-009 L-300A MP 235.55 CD-06A	Kern	ATS	4-Feb-14	6-Feb-14	N/A	$ 43,520.90	$ 25,211.36	$ 425.15	$ 12,937.11	$ 4,947.28	N/A	$ -	$ -	N/A	Added project for Non-destructive Examination.
13	23787	31998	30842169	RT-043 DREG4548-SI REPL PH1	Yuba City	GT/GC	21-Jan-14	13-Feb-14	$ 210,808.00	$ 203,667.65	$ 115,104.55	$ 18,991.12	$ 47,966.20	$ 21,605.78	$ (7,140.35)	$ -	$ -	No	Project addresses partial scope of originally filed TAPS project.
14	23689	31993	30842126	RT-047 DCUST2473-SJ REPL PH1	Morgan Hill	GT/GC	19-Feb-14	20-Feb-14	$ 129,989.00	$ 46,869.13	$ 70,711.32	$ 11.42	$ 18,392.65	$ (42,246.26)	$ (83,119.87)	$ 51,318.79	$ -	No	Project addresses partial scope of originally filed TAPS project.
15	#N/A	30070	41871410	D-014A L-300A MP 354.35 ID-18-1	Kettleman City	Mears	17-Feb-14	24-Feb-14	$ 789,456.00	$ 628,645.23	$ 136,513.63	$ 38.25	$ 488,484.50	$ 3,608.85	$ (160,810.77)	$ -	$ -	No	Added project (Original PSRS 24022 for Inspection) to complete post inspection analysis.
16	#N/A	30070	41871410	D-014C L-300A MP 372.97 ID-18-3	Coalinga	Mears	13-Feb-14	24-Feb-14	See project D-014A above	See project D-014A above	See project D-014A above	See project D-014A above	See project D-014A above	See project D-014A above	See project D-014A above	See project D-014A above	See project D-014A above	See project D-014A above	Added project (Original PSRS 24022 for Inspection) to complete post inspection analysis.
17	23787	31999	31031884	RT-044 DREG4567-SI REPL PH1	Wheatland	GT/GC	12-Feb-14	24-Feb-14	$ 126,883.00	$ 223,791.73	$ 156,121.81	$ 2,493.20	$ 38,720.54	$ 26,456.18	$ 96,908.73	$ -	$ -	Yes	Project addresses partial scope of originally filed TAPS project.
18	23787	31837	41962520	TS-025-14, DCUST1614, Test, Marysville	Marysville	GT/GC	11-Feb-14	26-Feb-14	$ 544,761.11	$ 204,794.94	$ 128,616.41	$ 2,704.88	$ 68,630.79	$ 4,842.86	$ (339,966.17)	$ 59,103.20	$ -	No	-
19	#N/A	24027	41476259	I-060 L-101(S) MP 0.00-11.62 ILI & Analysis PH1	Milpitas	GT/GC	6-Feb-14	1-Mar-14	$ 1,612,515.00	$ 1,753,149.45	$ 818,065.54	$ 60,956.79	$ 759,555.87	$ 114,571.25	$ 140,634.45	$ -	$ -	No	-
20	23749	31971	31031731	RT-023 GCUST5901-MI REPL PH1	San Leandro	GT/GC	24-Feb-14	5-Mar-14	$ 221,067.00	$ 230,443.98	$ 228,173.10	$ 13,206.39	$ 32,294.59	$ (43,230.10)	$ 9,376.98	$ 88,206.31	$ -	No	Project addresses partial scope of originally filed TAPS project.
21	23776	31979	31031897	RT-030 STUB8663-STUB8664-STUB8665-NV REPL PH1	Gridley	GT/GC	2-Mar-14	8-Mar-14	$ 267,269.00	$ 150,066.02	$ 168,549.00	$ 6,192.26	$ 96,840.90	$ (121,516.14)	$ (117,202.98)	$ 148,111.25	$ -	No	Project addresses partial scope of originally filed TAPS project.
22	#N/A	30907	41921650	T-300-14, L-2, Test, Los Banos	Los Banos	Snelson	11-Feb-14	11-Mar-14	$ 2,768,785.31	$ 2,174,123.32	$ 302,660.98	$ 87,773.23	$ 1,691,235.07	$ 92,454.04	$ (594,661.99)	$ 2,174,123.32	$ -	No	-
23	24272	29275	30965594	R-157 DFM-1603-01 1.42MI MP 0.07-1.30 REPL PH1	Lathrop	GT/GC	17-Sep-13	14-Mar-14	$ 5,817,458.00	$ 6,423,160.16	$ 3,110,766.18	$ 536,660.96	$ 3,009,580.47	$ (233,847.45)	$ 605,702.16	$ 1,382,825.94	$ -	Yes	Added as new replacement project from filed test project after most of test was removed due to records verified.
24	23749	31969	31031728	RT-021 DREG4872-MI REPL PH1	San Lorenzo	GT/GC	7-Mar-14	14-Mar-14	$ 396,848.00	$ 159,259.86	$ 162,753.14	$ 2,293.57	$ 34,019.96	$ (39,806.81)	$ (237,588.14)	$ 88,206.31	$ -	No	Project addresses partial scope of originally filed TAPS project.
25	#N/A	30070	41871410	D-014B L-300A MP 369.72 ID-18-2	Coalinga	Mears	10-Mar-14	17-Mar-14	See project D-014A above	See project D-014A above	See project D-014A above	See project D-014A above	See project D-014A above	See project D-014A above	See project D-014A above	See project D-014A above	See project D-014A above	See project D-014A above	Added project (Original PSRS 24022 for Inspection) to complete post inspection analysis.
26	23785	32012	31031848	RT-061 DREG4420-YO REPL PH1	Madera	GT/GC	10-Mar-14	17-Mar-14	$ 262,069.00	$ 246,868.17	$ 167,475.97	$ 8,980.41	$ 66,370.89	$ 4,040.90	$ (15,200.83)	$ 27,622.40	$ -	No	Project addresses partial scope of originally filed TAPS project.
27	23787	32000	31031888	RT-045 STUB6039-SI REPL PH1	Live Oak	GT/GC	12-Mar-14	18-Mar-14	$ 134,321.00	$ 215,689.94	$ 151,581.35	$ 5,657.30	$ 34,446.55	$ 24,004.74	$ 81,368.94	$ -	$ -	Yes	Project addresses partial scope of originally filed TAPS project.
28	23789	31822	41961402	R-207 L-177A 0.01MI MP 26.55-26.55 REPL PH1	Corning	GT/GC	10-Mar-14	20-Mar-14	$ 555,421.00	$ 482,465.28	$ 395,209.56	$ 12,842.84	$ 104,306.92	$ (29,894.04)	$ (72,955.72)	$ 92,044.62	$ -	No	-
29	23539	31771	41954808	T-215-13, L-400, Test, Oakley	Oakley	ARB	18-Feb-14	26-Mar-14	$ 2,840,226.63	$ 3,818,418.49	$ 753,289.46	$ 148,163.61	$ 2,774,272.82	$ 142,692.60	$ 978,191.86	$ 3,818,418.49	$ -	Yes	Delayed from 2013 to 2014.
30	23750	31951	31032381	RT-004 DREG5148-CC REPL PH1	Santa Cruz	GT/GC	17-Mar-14	27-Mar-14	$ 490,288.00	$ 371,149.50	$ 308,550.36	$ 59,957.00	$ 45,053.69	$ (42,411.55)	$ (119,138.50)	$ 96,497.14	$ -	No	Project addresses partial scope of originally filed TAPS project.
31	23741	33217	31062555	RT-010 STUB9046-DI REPL PH1	Brentwood	GT/GC	17-Mar-14	28-Mar-14	$ 229,007.00	$ 69,569.03	$ 49,970.57	$ 1,614.14	$ 10,233.64	$ 7,750.68	$ (159,437.97)	$ -	$ -	No	Project addresses partial scope of originally filed TAPS project.
32	23828	31369	41931149	T-405-14, DFM-1209-01, Test, Fowler	Fowler	Snelson	11-Mar-14	2-Apr-14	$ 1,736,433.08	$ 1,219,284.46	$ 220,155.34	$ 6,273.61	$ 947,883.61	$ 44,971.90	$ (517,148.62)	$ 1,219,284.46	$ -	No	Approx. 1,400 feet added to facilitate staging and implement traffic control.
33	#N/A	29634	30976002	VA-085 Valve Auto - L-300A MLV 328.06, 1V, PH1	Fresno	GT/GC	5-Dec-13	3-Apr-14	$ 774,482.00	$ 480,726.54	$ 267,807.54	$ 140,499.45	$ 19,638.01	$ 52,781.54	$ (293,755.46)	$ -	$ -	No	New project to Re-Automate RCV V-328.06 using PSEP valve automation standard design. This valve was planned for replacement in 2013 under the PSEP In Line Inspection project for pigability upgrades on L 300A - PSRS 24023 (L-300A MP 299-352 UPGRADE PH-1).
34	#N/A	29635	30976003	VA-086 Valve Auto - L-300B MLV 327.83, 1V, PH1	Fresno	GT/GC	5-Dec-13	11-Apr-14	$ 728,601.00	$ 524,357.14	$ 294,152.06	$ 129,441.68	$ 42,860.85	$ 57,902.55	$ (204,243.86)	$ -	$ -	No	MLV 328.06 is an existing RCV with an obsolete actuator. This valve was planned for replacement in 2013 under the PSEP In Line Inspection project for pigability upgrades on L 300A - PSRS 24017 (L-300B MP 299-351.8 UPGRADE PH-1). It was recommended that the remote control functionality on this valve be maintained. Valve Automation will manage the automation of MLV 328.06.
35	23787	30979	41929493	TS-015-14, GCUST5765, Test, Live Oak	Live Oak	GT/GC	7-Apr-14	14-Apr-14	$ 853,615.17	$ 378,309.01	$ 283,943.14	$ 3,330.26	$ 78,338.85	$ 12,696.76	$ (475,306.16)	$ 109,178.83	$ -	No	Scope decreased by approx. 250 feet due to previous testing on a 2013 ILI project.
36	23740	31981	41977983	RT-032 DREG3759-PN REPL PH1 Expense	Half Moon Bay	GT/GC	8-Apr-14	15-Apr-14	$ 95,687.00	$ 107,630.33	$ 95,800.95	$ 2,770.16	$ 12,993.07	$ (3,933.85)	$ 11,943.33	$ 8,236.60	$ -	Yes	Project addresses partial scope of originally filed TAPS project.
37	#N/A	29426	41833980	TS-001-13, L-105N-3, Test, Oakland	Oakland	ARB	17-Mar-14	16-Apr-14	$ 1,405,867.13	$ 1,214,485.02	$ 209,760.80	$ 14,862.79	$ 948,006.75	$ 41,854.68	$ (191,382.11)	$ 1,214,485.02	$ -	No	New project that - nitrogen test of 166 feet of PH2 pipe in a class 3 location
38	23785	32184	41929627	TS-019-14, DREG4388, Test, Merced	Merced	Snelson	26-Mar-14	16-Apr-14	$ 1,274,222.67	$ 982,510.46	$ 158,106.80	$ 13,568.08	$ 789,171.95	$ 21,663.63	$ (291,712.21)	$ 545,647.55	$ -	No	-
39	23973	23973	30841958	VA-077 Valve Auto - Cummings Creek, 1V, PH1	Fortuna	Underground	10-Mar-14	16-Apr-14	$ 591,123.00	$ 553,299.83	$ 254,053.69	$ 80,486.25	$ 177,875.24	$ 40,884.65	$ (37,823.17)	$ -	$ -	No	-
40	23928	31988	31031651	RT-039 STUB8028-SA REPL PH1	Woodland	GT/GC	23-Apr-14	23-Apr-14	$ 39,807.00	$ 48,425.08	$ 37,595.38	$ 645.71	$ 6,417.15	$ 3,766.84	$ 8,618.08	$ -	$ -	Yes	Project addresses partial scope of originally filed TAPS project.
41	23750	31840	41962988	TS-022-14, DREG4260, Test, Salinas	Salinas	Underground	7-Apr-14	24-Apr-14	$ 1,423,277.40	$ 1,388,032.30	$ 195,174.57	$ 3,505.75	$ 1,122,542.62	$ 66,809.36	$ (35,245.10)	$ 959,484.16	$ -	No	-
42	23689	31839	41962986	TS-032-14, DREG4145, Test, San Jose	San Jose	Underground	2-Apr-14	26-Apr-14	$ 1,263,098.89	$ 1,652,766.64	$ 281,579.02	$ (2,741.01)	$ 1,340,751.16	$ 33,177.47	$ 389,667.75	$ 556,432.86	$ -	Yes	-
43	#N/A	30908	41921652	T-301-14, L-2, Test, Westley	Westley	Snelson	6-Mar-14	28-Apr-14	$ 3,665,642.34	$ 5,082,830.67	$ 394,870.87	$ 146,944.38	$ 4,344,165.77	$ 196,849.65	$ 1,417,188.33	$ 5,049,952.15	$ -	Yes	-
44	#N/A	32882	42076761	T-358B-14, DREG5496, Test, Ridgecrest	Ridgecrest	GT/GC	28-Mar-14	5-May-14	See project T-358A-14	See project T-358A-1	See project T-358A-	See project T-358A	See project T-358A	See project T-358A-	See project T-358A-14	See project T-358A-14	See project T-358A-14	See project	TTest added for clearance efficiency. Added 1,442 feet of PH2 class 3 pipe.
45	23535	30909	41922150	T-379-14, L-021F, Test, San Rafael	San Rafael	ARB	20-Mar-14	5-May-14	$ 2,362,235.44	$ 2,169,601.41	$ 325,544.07	$ 12,959.75	$ 1,735,664.55	$ 95,433.04	$ (192,634.03)	$ 1,365,427.23	$ -	No	-
46	23471	23471	41918943	T-235-13, L-131Z, Test, Rio Vista	Rio Vista	GT/GC	3-Mar-14	6-May-14	$ 1,887,016.14	$ 1,601,973.54	$ 869,330.54	$ 42,927.08	$ 463,699.65	$ 226,016.27	$ (285,042.60)	$ 249,142.79	$ -	No	Delayed from 2013 to 2014 to coordinate with other work in the vicinity. 800 feet split off into PSRS 27760 due to separate clearance requirements
47	23974	23974	30842321	VA-078 Valve Auto - Tompkins Hill, 3V, PH1	Fortuna	Underground	11-Mar-14	8-May-14	$ 1,177,108.00	$ 1,868,307.43	$ 416,461.23	$ 220,616.00	$ 1,128,698.62	$ 102,531.58	$ 691,199.43	$ -	$ -	Yes	-
48	23895	31054	41946507	T-348-14, DFM-2408-01, Test, Livermore	Livermore	Underground	17-Apr-14	12-May-14	$ 1,789,936.46	$ 1,415,119.17	$ 243,946.00	$ 7,502.67	$ 1,116,155.59	$ 47,514.91	$ (374,817.29)	$ -	$ -	No	-
49	23481	30889	41913331	T-375-14, DFM-7226-02, Test, Modesto	Modesto	Snelson	23-Apr-14	13-May-14	$ 1,826,524.47	$ 1,491,258.93	$ 212,443.92	$ 11,537.74	$ 1,224,337.33	$ 42,939.94	$ (335,265.54)	$ 1,491,258.93	$ -	No	2,022 ft. added for constructability due to a uncooperative land owner.
50	23529	29053	30959338	R-145 L-306 0.01MI MP 43.30-43.31 REPL PH1	Paso Robles	Underground	31-Mar-14	14-May-14	$ 450,076.00	$ 909,982.75	$ 367,836.21	$ 8,226.77	$ 534,498.32	$ (578.55)	$ 459,906.75	$ 81,975.88	$ -	Yes	Added as short replacement project for cost efficiency reasons because all except 50 ft. of filed test was removed from PH1 due to records verification; subsequently delayed from 2013 to 2014 due to schedule and workload balancing.
51	#N/A	30901	41921653	T-328-14, DFM-1320-01, Test, Fortuna	Fortuna	Underground	22-Apr-14	14-May-14	$ 1,031,770.27	$ 614,411.79	$ 141,340.96	$ 1,552.03	$ 458,484.78	$ 13,034.02	$ (417,358.48)	$ 25,153.86	$ -	No	-
52	24890	27904	30940972	R-202 DFM-1607-01 1.11MI MP 0.00-1.62 REPL PH1	Stockton	GT/GC	1-Jul-13	20-May-14	$ 4,596,910.00	$ 7,127,141.63	$ 2,740,269.67	$ 548,289.75	$ 3,550,943.12	$ 287,639.09	$ 2,530,231.63	$ 471,919.39	$ -	Yes	120 ft. added as a result of the difference between PFL and design drawings.
53	23912	30945	41920246	T-332A-14, DFM-1501-02, Test, Yuba City	Yuba City	GT/GC	7-Apr-14	20-May-14	$ 1,383,548.79	$ 1,355,200.24	$ 879,116.11	$ 17,476.32	$ 391,099.91	$ 67,507.90	$ (28,348.55)	$ 387,874.79	$ -	No	Scope decrease of 5,000 feet due to records verified.
54	23728	29124	30968134	R-230 L-103 0.01MI MP 22.20-22.21 REPL PH1	Salinas	GT/GC	1-Apr-14	22-May-14	$ 1,466,355.00	$ 1,625,977.09	$ 1,251,133.07	$ 117,938.04	$ 191,365.21	$ 65,540.77	$ 159,622.09	$ 155,760.46	$ -	Yes	Scope increase of 128 feet due to design drawings vs. PFL
55	23907	29715	41847701	T-358A-14, DFM-6603-01, Test, Ridgecrest	Ridgecrest	GT/GC	4-Mar-14	22-May-14	$ 3,911,572.06	$ 4,225,657.38	$ 2,496,000.33	$ 48,894.30	$ 1,367,428.09	$ 313,334.66	$ 314,085.32	$ 4,046,787.16	$ -	No	Scope increased by 30,000 feet to pick up adjacent PH2 pipe.
56	23579	23579	41918948	T-335B-14, DFM-1502-11, Test, Marysville	Marysville	Underground	28-Apr-14	27-May-14	$ 3,925,193.43	$ 1,794,742.13	$ 545,267.16	$ 11,473.99	$ 1,199,019.30	$ 38,981.68	$ (2,130,451.30)	$ 679,278.67	$ -	No	-
57	23667	23667	30842311	VA-067 Valve Auto - Ripon-Modesto, 3V, PH1	Manteca	Snelson	24-Feb-14	30-May-14	$ 1,526,128.02	$ 1,687,061.10	$ 624,087.29	$ 438,646.15	$ 1,671,577.88	$ (1,047,250.22)	$ 160,933.08	$ -	$ -	Yes	-
58	24055	31267	31008875	R-199 L-021H 0.06MI MP 6.38-6.42 REPL PH1	Vallejo	GT/GC	28-Apr-14	4-Jun-14	$ 699,459.00	$ 514,258.40	$ 563,075.15	$ 43,077.87	$ 148,363.68	$ (240,258.30)	$ (185,200.60)	$ 375,129.81	$ -	No	-
59	23520	30925	41921654	T-345B-14, L-197B, Test, Woodbridge	Woodbridge	Underground	24-Apr-14	4-Jun-14	$ 1,774,054.61	$ 1,379,024.52	$ 259,021.01	$ 11,201.38	$ 1,071,835.03	$ 36,967.10	$ (395,030.09)	$ -	$ -	No	-
60	23650	23650	30841470	VA-075 Valve Auto - Gosford Rd Mtr Sta, 3V, PH1	Bakersfield	GT/GC	31-Mar-14	4-Jun-14	$ 1,217,654.33	$ 1,300,892.92	$ 745,158.98	$ 221,894.48	$ 197,239.23	$ 136,600.23	$ 83,238.59	$ -	$ -	No	-
61	#N/A	31693	30842164	R-066 L-119B 1.12MI MP 0.59-2.23 REPL PH1	Sacramento	GT/GC	21-Jan-14	5-Jun-14	$ 7,335,684.00	$ 7,257,707.56	$ 3,192,145.43	$ 374,238.39	$ 2,449,266.08	$ 1,242,057.66	$ (77,976.44)	$ -	$ -	No	Added new replacement project from filed test project as a result of data validation.
62	23652	23652	30841471	VA-074 Valve Auto - Union Ave Meter Reg Sta, 1V, PH1	Bakersfield	GT/GC	24-Feb-14	5-Jun-14	$ 1,231,687.45	$ 971,894.19	$ 504,642.17	$ 149,918.40	$ 215,372.62	$ 101,961.00	$ (259,793.26)	$ -	$ -	No	-
63	23690	31961	31030478	RT-014 DREG4794-FR REPL PH1	Fresno	GT/GC	28-May-14	6-Jun-14	$ 133,694.00	$ 75,823.02	$ 217,067.45	$ 977.85	$ 2,881.08	$ (145,103.36)	$ (57,870.98)	$ 173,526.47	$ -	No	Project addresses partial scope of originally filed TAPS project.
64	23928	31985	31031645	RT-036 DREG4050-SA REPL PH1	Sacramento	GT/GC	12-May-14	7-Jun-14	$ 592,817.00	$ 607,654.30	$ 463,337.32	$ 58,578.53	$ 54,499.32	$ 31,239.13	$ 14,837.30	$ 56,696.75	$ -	No	Project addresses partial scope of originally filed TAPS project.
65	23884	23884	41919090	T-319-14, DFM-0621-01, Test, Woodland	Woodland	GT/GC	30-Apr-14	13-Jun-14	$ 2,120,421.54	$ 1,225,519.31	$ 849,304.86	$ 24,658.98	$ 284,818.74	$ 66,736.73	$ (894,902.23)	$ 42,613.91	$ -	No	Scope increase of 1663 ft. in Q2 due to adjacent phase 1 test segments that were mislabeled as Distribution.
66	#N/A	32383	42045595	T-303A-14, L-186, Test, Dos Palos	Dos Palos	Underground	15-May-14	18-Jun-14	$ 1,853,106.23	$ 1,433,653.01	$ 299,408.59	$ 8,623.94	$ 1,110,606.53	$ 15,013.95	$ (419,453.22)	$ 796,194.32	$ -	No	Split from project PSRS 31108
67	23750	31948	30842139	RT-001 DF3429-CC REPL PH1	Santa Cruz	GT/GC	2-Jun-14	24-Jun-14	$ 515,223.00	$ 576,880.59	$ 447,111.95	$ 152,584.89	$ 10,440.86	$ (33,257.11)	$ 61,657.59	$ 96,497.14	$ -	Yes	Project addresses partial scope of originally filed TAPS project.
68	23689	32050	41975666	TS-026-14, X6511, Test, Milpitas	Milpitas	Underground	21-May-14	25-Jun-14	$ 2,157,886.84	$ 2,026,635.79	$ 279,211.65	$ 128,409.23	$ 1,588,972.15	$ 30,042.76	$ (131,251.05)	$ 682,302.46	$ -	No	-

TABLE 11-1
PACIFIC GAS AND ELECTRIC COMPANY
PROJECT STATUS SUMMARY - PROJECTS COMPLETED
JANUARY 1, 2014 – JUNE 30, 2014

Line #	PSEP Filing PSRS	New PSRS	Order Number	Project Description	City	Construction Contractor	Mobilization Date	Tie-in Date	Job Estimate Amount	Total Cost	Labor Cost	Materials Cost	Contracts Cost	Other Cost	Variance to Budget	PSEP Disallowed Cost	Non-PSEP costs	>10% Over Budget	Comments
69	23665	23665	30842258	VA-058 Valve Auto - 24th & 20th Ave, 3V, PH1	Sacramento	GT/GC	3-Feb-14	26-Jun-14	$ 1,641,677.00	$ 1,144,777.34	$ 612,071.65	$ 128,509.52	$ 263,168.31	$ 141,027.86	$ (496,899.66)	$ -	$ -	No	Allocated flow meter(s) to project with zero net impact to the program
70	23706	31843	41963808	TS-027-14, GCUST5752, Test, Tracy	Tracy	Snelson	11-Jun-14	28-Jun-14	$ 1,385,799.14	$ 1,031,736.88	$ 429,227.00	$ 27,618.76	$ 565,547.34	$ 9,343.78	$ (354,062.26)	$ 1,027,739.26	$ -	No	-
71	23912	30946	41920247	T-332B-14, DFM-1501-02, Test, Yuba City	Yuba City	GT/GC	7-Apr-14	30-Jun-14	$ 2,052,122.95	$ 141,486.67	$ 70,303.62	$ -	$ 62,406.44	$ 8,776.61	$ (1,910,636.28)	$ 133,050.71	$ -	No	Approx. 4,000 ft. added for constructability and staging.
72	23911	31370	41931281	T-368-14, DFM-1501-01, Test, Yuba City	Yuba City	GT/GC	14-Apr-14	30-Jun-14	$ 2,621,759.03	$ 865,050.50	$ 633,206.13	$ 20,298.74	$ 179,365.85	$ 32,179.78	$ (1,756,708.53)	$ -	$ -	No	10,400 feet is being added to pickup untested transmission pipe and distribution pipe which is 60 psi or greater.

TABLE 12-1
PACIFIC GAS AND ELECTRIC COMPANY
PROJECT STATUS SUMMARY - PROJECTS BEGUN BUT CURRENTLY UNFINISHED
JANUARY 1, 2014 – JUNE 30, 2014

Line #	PSEP Filing PSRS	New PSRS	Project Description	Mobilization Date	Tie-in Date	Job Estimate Amount	Comments
1	#N/A	30070	D-014D L-300A MP 387.87 ID-18-4	6/16/2014	7/11/2014	See project D-014A (tbl 11)	Added project (Original PSRS 24022 for Inspection) for Dig aspects.
2	#N/A	30070	D-014E L-300A MP 393.39 ID-18-5	6/21/2014	7/12/2014	See project D-014A (tbl 11)	Added project (Original PSRS 24022 for Inspection) for Dig aspects.
3	23750	32090	TS-008-14, GCUST5874, Test, Soledad	6/25/2014	7/12/2014	$ 775,793.86	-
4	23928	31986	RT-037 DREG4095-SA REPL PH1	6/30/2014	7/16/2014	$ 447,604.00	Project addresses partial scope of originally filed TAPS project.
5	23561	23561	T-326-14, L-126B, Test, Eureka	6/9/2014	7/16/2014	$ 2,224,276.44	-
6	23750	31846	TS-023-14, GCUST5872, Test, Soledad	6/25/2014	7/17/2014	$ 653,818.31	-
7	23668	23668	VA-066 Valve Auto - Cordelia, 6V, PH1	3/4/2014	7/17/2014	$ 2,929,205.00	-
8	23673	23673	VA-060 Valve Auto - N Sac Ugnd Hldr, 3V, PH1	4/3/2014	7/18/2014	$ 1,592,072.00	-
9	24196	31161	R-194 DFM-0611-05 0.07MI MP 0.00-0.12 REPL PH1	5/19/2014	7/21/2014	$ 1,395,806.00	-
10	23577	26124	T-076B-12, DFM-0611-02, Test, Sacramento	5/19/2014	7/21/2014	$ 2,572,993.00	Delayed from 2012 to 2014.
11	24196	25856	T-077-12, DFM-0611-05, Test, Sacramento	5/19/2014	7/21/2014	$ 1,491,078.47	Delayed from 2012 to 2014.
12	23533	25836	T-066-12, L-021C, Test, Cotati	6/24/2014	7/22/2014	$ 1,540,741.89	Delayed from 2012 to 2014.
13	23648	23648	VA-076 Valve Auto - Bakersfield Tap, 3V, PH1	5/19/2014	7/24/2014	$ 1,226,410.00	-
14	23672	23672	VA-064 Valve Auto - East Fairfield Station	6/16/2014	7/30/2014	$ 1,736,162.00	-
15	23574	25814	T-002-12, DFM-0401-01, Test, San Rafael	5/30/2014	8/4/2014	$ 2,291,659.62	Delayed from 2012 to 2014.
16	#N/A	32449	T-002A-12, DREG3883, Test, San Rafael	5/30/2014	8/4/2014	$ 1,823,197.27	New Project added to test this segment with other untested Class 3 pipe for clearance and construction efficiency.
17	23574	25817	T-003-12, DFM-0401-01, Test, San Rafael	5/30/2014	8/4/2014	$ 1,079,117.25	Delayed from 2012 to 2014.
18	23786	27752	R-104 DFM-0405-01 0.50MI MP 3.03-3.30 REPL PH1	4/28/2014	8/7/2014	$ 8,217,124.00	-
19	23874	25847	T-016-12, L-131_2, Test, Fremont	6/17/2014	8/8/2014	$ 4,134,867.66	Delayed from 2012 to 2014.
20	#N/A	31293	R-200 L-114 0.12MI MP 16.75-16.86 REPL PH1	6/30/2014	8/10/2014	$ 1,008,365.00	Added as new project as a result of data validation that identified a class location change.
21	#N/A	30948	T-022A-12, L-191-1, Test, Lafayette	6/24/2014	8/12/2014	$ 3,468,500.22	Scope decrease of 700 feet for records verified.
22	23753	31953	RT-006 DFDS3587-DA REPL PH1	5/21/2014	8/18/2014	$ 356,069.00	Project addresses partial scope of originally filed TAPS project.
23	23365	30791	R-192 L-109 0.03MI MP 9.87-9.88 REPL Spread 6B	6/19/2014	8/19/2014	$ 4,759,153.00	Delayed from 2012 to 2014.
24	#N/A	32864	VA-120 Valve Auto - Baseline Rd Lot Rebuild (R-059)	5/8/2014	9/12/2014	$ 514,655.00	-
25	23669	23669	VA-059 Valve Auto - Yolo Causeway Blvd Tie, 2V, PH1	6/19/2014	9/18/2014	$ 2,119,302.40	Added project to decrease automation from 3 to 2 actuated valves for efficiency.
26	23822	28468	R-059 L-123 4.01MI MP 0.00-9.74 REPL PH1 (partial retirement)	5/9/2014	10/15/2014	$ 46,356,307.00	Project at risk of non-completion in 2014.
27	23796	29631	R-205 L-021C 0.55MI MP 31.85-32.39 REPL PH1	6/23/2014	10/27/2014	$ 6,970,779.00	-
28	24052	29743	R-158 L-021D 0.62MI MP 18.65-19.27 REPL PH1	6/23/2014	11/4/2014	$ 6,418,273.00	Delayed from 2013 to 2014 due to permitsrequiring long lead times and land acquisition challenges. Approx. 1600 ft. added for proximity and program efficiency.
29	23894	23894	T-322-14, DFM-1027-01, Test, Oroville	5/12/2014	7/1/2014	$ 3,405,997.98	Added 3500 feet due to adjacent phase 1 segments.
30	23679	23679	VA-062 Valve Auto - Paramount Court, 1V, PH1	4/15/2014	7/2/2014	$ 3,033,835.00	Project addresses partial scope of originally filed TAPS project.
31	23559	23559	T-325-14, L-126A, Test, Eureka	5/7/2014	7/8/2014	$ 3,629,617.64	Scope decrease of 1900 feet to accommodate a tie into L-126A replacement PSRS 19388.
32	23794	33401	RT-017 DREG3841-HB REPL PH1 Expense	6/30/2014	7/9/2014	$ 248,702.00	Project addresses partial scope of originally filed TAPS project.
33	23661	23661	VA-056 Valve Auto - Bixler Rd, 3V, PH1	1/27/2014	7/9/2014	$ 3,279,021.00	Delayed from 2013 to 2014 because due to long lead items. In addition, this project required an outage on Line 57B, on which there is limited clearance availability as this line is the sole feed to PG&E's storage facilities on McDonald Island.
34	23815	23815	R-010 L-108_2 0.14MI MP 48.16-48.20 REPL PH1	4/1/2014	11/8/2014	$ 2,285,916.00	Project at risk of non-completion in 2014.
35	N/A	32950	T-408-14, Line L-124A, Linda	6/2/2014	7/2/2014	$ 1,953,104.59	Added Test - Filed as single REPL, now being done as 3 strength tests. Transfer most of the original replacement project scope to three strength tests due to constructability.
36	N/A	32951	T-409A-14, Line L-124A, Yuba City	6/21/2014	7/19/2014	$ 2,032,992.62	Added Test - Filed as single REPL, now being done as 3 strength tests. Transfer most of the original replacement project scope to three strength tests due to constructability.

TABLE 12-1
PACIFIC GAS AND ELECTRIC COMPANY
PROJECT STATUS SUMMARY - PROJECTS BEGUN BUT CURRENTLY UNFINISHED
JANUARY 1, 2014 – JUNE 30, 2014

Line #	PSEP Filing PSRS	New PSRS	Project Description	Mobilization Date	Tie-in Date	Job Estimate Amount	Comments
37	N/A	32951	T-409B-14, Line L-124A-1, Yuba City	6/21/2014	7/19/2014	See project T-409B-14	Added Test - Filed as single REPL, now being done as 3 most of the original replacement project scope to three strength tests due to constructability.
38	N/A	32952	T-410-14, Line L-124A, Yuba City	6/27/2014	8/7/2014	$ 1,900,309.05	Added Test - Filed as single REPL, now being done as 3 most of the original replacement project scope to three strength tests due to constructability.

TABLE 13-1
PACIFIC GAS AND ELECTRIC COMPANY
PROJECT STATUS SUMMARY - PROJECTS FORECASTED FOR PHASE 1 BUT YET TO START
REPORTING PERIOD JANUARY 1, 2014 – JUNE 30, 2014

Line #	PSEP Filing PSRS	New PSRS	Project Description	Mobilization Date	Tie-in Date	Job Estimate Amount	Comments
1	23794	33400	RT-016 DCUST9089-HB REPL PH1 Expense	7/7/2014	7/10/2014	$ -	Project addresses partial scope of originally filed TAPS project.
2	23785	32017	RT-066 STUB6099-YO REPL PH1	7/7/2014	7/15/2014	$ 147,865.00	Project addresses partial scope of originally filed TAPS project.
3	23785	32015	RT-064 DREG4453-YO REPL PH1	7/9/2014	7/18/2014	$ 516,508.00	Project addresses partial scope of originally filed TAPS project.
4	#N/A	33580	D-096 L-303 MP 42.43 TD14-06	7/28/2014	8/1/2014	$ -	-
5	23744	32003	RT-053 X6335-SO REPL PH1 (R-418 Betterment)	7/21/2014	8/1/2014	$ -	Project addresses partial scope of originally filed TAPS project.
6	23706	32008	RT-057 DREG4892-ST REPL PH1	7/21/2014	8/1/2014	$ 528,731.00	Project addresses partial scope of originally filed TAPS project.
7	#N/A	31366	R-204 L-301C 0.01MI MP 17.25-17.26 REPL PH1	7/14/2014	8/2/2014	$ -	Added as new project as a result of data validation; pipe replacement due to short length. JE in progress.
8	23849	23849	R-201 DFM-0404-11 0.02MI MP 0.00-0.04 REPL PH1	7/7/2014	8/8/2014	$ 1,308,153.00	Delayed from 2013 to 2014 as a result of data validation.
9	23744	32002	RT-052 DREG3803-SO REPL PH1	8/4/2014	8/8/2014	$ -	Project addresses partial scope of originally filed TAPS project.
10	23880	23880	T-244-13, DFM-1815-15, Test, Monterey	7/9/2014	8/8/2014	$ 2,295,838.48	Project delayed from 2013 to 2014. Scope increased for program efficiency
11	23706	32005	RT-054 DCUST1739-ST REPL PH1	TBD	8/9/2014	$ 237,760.00	Project addresses partial scope of originally filed TAPS project.
12	23811	23811	R-062 DFM-0603-01 0.68MI MP 0.00-0.57 REPL PH1 (partial retirement)	7/15/2014	8/13/2014	$ 1,851,680.00	Delayed from 2013 to 2014 due to environmental/species impacts experienced during construction and subsequently due to clearance schedule balancing related to high winter gas loads.
13	23780	29401	R-064 DFM-0604-16 0.19MI MP 0.00-0.18 REPL PH1	7/15/2014	8/14/2014	$ 823,352.00	-
14	#N/A	30894	T-361-14, L-301B, Test, Prunedale	7/21/2014	8/14/2014	$ 2,393,812.49	Added new project on L-301B. Identified through data validation by decision tree. (0.63 mile)
15	23575	23575	T-075-12, DFM-0611-01, Test, Sacramento	7/7/2014	8/15/2014	$ 2,086,136.40	Delayed from 2012 to 2014 due to project complexity and for construction efficiency.
16	23718	31975	RT-027 DFDS3544-DREG3876-NB REPL PH1	8/11/2014	8/21/2014	$ -	Project addresses partial scope of originally filed TAPS project.
17	23783	23783	R-177 DFM-1509-01 0.27MI MP 0.05-0.33 REPL PH1	7/18/2014	8/27/2014	$ 1,969,210.00	-
18	#N/A	31336	R-197 DFM-6605-01 0.05MI MP 0.00-0.05 REPL PH1	8/1/2014	8/27/2014	$ -	New project added. Data validation decision tree resulted in phase 1 strength test, replaced due to short length. JE in progress
19	23780	29425	R-152 DFM-0604-16 0.31MI MP 0.18-0.50 PH1 Downrate	8/11/2014	8/29/2014	$ -	Delayed from 2013 to 2014 due to due to environmental permitting delay. JE in progress.
20	23706	32006	RT-055 DREG4921-ST REPL PH1	8/4/2014	8/29/2014	$ -	Project addresses partial scope of originally filed TAPS project.
21	23785	32018	RT-067 STUB6102-YO REPL PH1	8/26/2014	8/29/2014	$ 234,268.00	Project addresses partial scope of originally filed TAPS project
22	23785	32020	RT-069 STUB6183-YO REPL PH1	8/8/2014	8/30/2014	$ -	Project addresses partial scope of originally filed TAPS project. JE in progress.
23	23574	25818	T-004-12, DFM-0401-01, Test, San Rafael	7/21/2014	2015	$ -	Delayed from 2012 to 2013 to accommodate other higher priority tests for Integrity Management in 2012. Then further delayed to 2014 due to schedule and workload balancing. This project, in conjunction with T-005 DFM 0401-01 Test PRSR # 25823 is at risk of being delayed into 2015.
24	23540	23540	T-313-14, L-050A, Test, Chico	7/21/2014	9/3/2014	$ -	JE in progress.
25	#N/A	33795	D-091 DFM-0833-01 MP 5.24 TD14-01	9/2/2014	9/4/2014	$ -	
26	23584	27607	T-221-13, DFM-0405-01, Test, Napa	7/8/2014	9/5/2014	$ 2,861,133.28	Delayed from 2013 to 2014 for constructability reasons related to a construction moratorium on the road under where the line runs.
27	23776	31842	TS-024-14, DREG5480, Test, Redding	7/30/2014	9/5/2014	$ -	JE in progress.
28	#N/A	33798	D-092 DFM0834-01 MP 3.58 TD14-02	9/4/2014	9/8/2014	$ -	-
29	23724	25719	R-067 L-109_2B 0.18MI MP 2.82-10.15 REPL PH1	7/7/2014	9/9/2014	$ 7,608,833.00	Delayed from 2013 to 2014 due to permitting and planning constraints. Approx.. 600 feet added with the design phase for constructability.
30	#N/A	33796	D-093 DFM-0405-01 MP 5.42 TD14-03	9/8/2014	9/10/2014	$ -	-
31	23740	32603	RT-031 DF3216-PN REPL PH1	8/25/2014	9/10/2014	$ -	Project addresses partial scope of originally filed TAPS project.
32	23689	31996	RT-050 DREG4161-SJ REPL PH1	9/2/2014	9/12/2014	$ -	Project addresses partial scope of originally filed TAPS project.
33	23785	32011	RT-060 DF3338-DREG4460-YO REPL PH1	9/2/2014	9/12/2014	$ 343,377.00	Project addresses partial scope of originally filed TAPS project.
34	23929	25886	T-094A-12, DFM-1816-01, Test, Santa Cruz	8/16/2014	9/12/2014	$ -	Delayed from 2013 to 2014 to balancing of resources (CNG/LNG) related to providing adequate customer support during clearance. This project, in conjunction with T-095 DFM 1816-01 PSRS # 25888 is at risk of being delayed to 2015.
35	#N/A	33786	D-095 DFM-1615-04 MP 0.02 TD14-05	9/10/2014	9/13/2014	$ -	-
36	23702	27951	R-061 L-196A 2.00MI MP 11.58-13.45 REPL PH1 (partial retirement)	8/16/2014	9/13/2014	$ -	Delayed from 2013 to 2014 due to scheduling and workload balancing. JE in progress.
37	#N/A	33797	D-097 L-314B MP 0 TD14-07	9/13/2014	9/16/2014	$ -	-
38	23489	27619	T-236-13, L-137B, Test, Eureka	7/15/2014	9/16/2014	$ -	Delayed from 2013 to 2014 due to permit delays. JE in progress.
39	24010	24010	I-063 L-131 MP 50.5-57.4 ILI & Analysis PH1	8/5/2014	9/18/2014	$ 1,360,455.00	-

TABLE 13-1
PACIFIC GAS AND ELECTRIC COMPANY
PROJECT STATUS SUMMARY - PROJECTS FORECASTED FOR PHASE 1 BUT YET TO START
REPORTING PERIOD JANUARY 1, 2014 – JUNE 30, 2014

Line #	PSEP Filing PSRS	New PSRS	Project Description	Mobilization Date	Tie-in Date	Job Estimate Amount	Comments
40	23870	30338	R-187 DFM-1816-15 0.03MI MP 3.04-3.07 REPL PH1	8/25/2014	9/18/2014	$ -	Added from filed test project due to short length. It is more cost efficient to replace this short length rather than strength test. JE in progress.
41	23740	31983	RT-034 DREG4339-PN REPL PH1 Expense	9/15/2014	9/18/2014	$ -	Project addresses partial scope of originally filed TAPS project. JE in progress.
42	#N/A	30922	T-363-14, L-142S, Test, Bakersfield	7/28/2014	9/18/2014	$ -	Added as new project as a result of data validation. JE in progress.
43	23796	29633	R-153 L-021C 0.19MI MP 34.84-35.04 REPL PH1	7/28/2014	9/19/2014	$ -	-
44	24026	24026	I-062 L-132 MP 31.7-38.4 ILI & Analysis PH1	9/11/2014	9/20/2014	$ -	Project at risk of non-completion in 2014. JE in progress.
45	23704	30361	R-165 L-109_3AA 0.27MI MP 17.01-17.11 REPL PH1	8/5/2014	9/20/2014	$ -	Decrease scope of 587 ft. based on design drawings. JE in progress.
46	23883	23883	T-341-14, DFM-1869-01, Test, Salinas	9/8/2014	9/20/2014	$ -	JE in progress.
47	23646	23646	VA-079 Valve Auto - 2AX Pls, 2V, PH1	9/6/2014	9/23/2014	$ -	JE in progress.
48	23928	31984	RT-035 DFDS3613-DREG4482-SA REPL PH1	9/2/2014	9/24/2014	$ -	Project addresses partial scope of originally filed TAPS project.
49	23724	29697	T-402-14, L-109, Test, San Jose	8/25/2014	9/25/2014	$ -	Delayed from 2013 to 2014. 566 feet of pipeline was driven to a phase 1 strength test by the decision tree. JE in progress.
50	23728	31033	R-190 L-103 0.17MI MP 9.71-9.86 REPL PH1	8/18/2014	9/26/2014	$ -	Delayed from 2014 to 2015. JE in progress.
51	24055	31276	R-206 L-021H 0.01MI MP 1.07-1.07 REPL PH1	9/2/2014	9/26/2014	$ -	JE in progress.
52	23749	31972	RT-024 STUB7837-MI REPL PH1	9/22/2014	9/26/2014	$ 229,137.00	Project addresses partial scope of originally filed TAPS project.
53	23633	23633	VA-042 Valve Auto - Vargas Crossover 2V, PH1	8/25/2014	9/27/2014	$ -	Delayed from 2013 to 2014 for constructability reasons and due to scheduling and workload balancing. Automating 2 different valves. JE in progress.
54	23514	23514	T-343-14, L-191A, Test, Orinda	7/30/2014	9/29/2014	$ -	JE in progress.
55	23704	30589	R-166 L-109_3B_2 1.64MI MP 20.38-22.20 REPL PH1	7/22/2014	9/30/2014	$ -	Added 418 ft. of replacement to project for constructability and transferred 104 ft. to test for efficiency. JE in progress.
56	23785	32016	RT-065 DREG4454-YO REPL PH1	9/15/2014	9/30/2014	$ 222,981.00	Project addresses partial scope of originally filed TAPS project.
57	23785	32019	RT-068 STUB6104-YO REPL PH1	9/15/2014	9/30/2014	$ -	JE in progress.
58	24901	24901	R-203 L-118-1 0.02MI MP 0.01-0.03 REPL PH1	9/2/2014	10/8/2014	$ -	Delayed from 2013 to 2014 due to schedule and workload balancing. JE in progress.
59	23590	25832	T-010-12, DFM-0407-01, Test, Napa	8/15/2014	10/10/2014	$ -	Delayed from 2012 to 2014 to accommodate other higher priority tests for Integrity Management in 2012. Then further delayed to 2014 due to schedule and workload balancing. JE in progress.
60	23688	26048	R-103 L-114_2 2.17MI MP 10.50-12.68 REPL PH1	7/14/2014	10/13/2014	$ 13,908,817.00	Delayed from 2012 to 2014 due to permits requiring long lead times.
61	24052	32885	R-417 L-021D 0.02MI MP 23.75-24.50 REPL PH1	8/20/2014	10/14/2014	$ -	This project is being split because the replacement spreads are almost two miles apart and it is more productive to design and construct them on different schedules.
62	24028	24028	I-061 L-101 MP 11.62-33.68 ILI & Analysis PH1	9/9/2014	10/15/2014	$ 1,403,990.00	-
63	23822	30616	R-167 L-123 1.83MI MP 4.35-13.74 REPL PH1	8/4/2014	10/16/2014	$ -	Added 1800 ft. due to minor re-route and based on design drawings. Project at risk of non-completion in 2014. JE in progress.
64	23692	30667	R-185 L-109_4A_2 1.04MI MP 28.60-29.60 REPL PH1	8/8/2014	10/18/2014	$ -	Project at risk of non-completion in 2014. JE in progress.
65	23657	23657	VA-054B Valve Auto - Brentwood Terminal, 8V, PH1 L-002	7/7/2014	10/21/2014	$ -	Delayed from 2013 to 2014 due to scheduling and workload balancing. JE in progress.
66	24059	26057	R-055 L-057A 1.33MI MP 8.73-10.18 REPL PH1	8/11/2014	10/23/2014	$ -	Delayed from 2013 to 2014 due to scheduling and workload balancing and constructability. JE in progress.
67	23972	23972	VA-044 Valve Auto - Sheridan Rd, 2V, PH1 (S-084)	7/16/2014	10/23/2014	$ -	Delayed from 2013 to 2014 due to the presence of CA Tiger Salamander. Project at risk of non-completion in 2014.JE in progress.
68	24024	24024	I-064 L-300A MP 299.00-352 ILI & Analysis PH1	10/1/2014	10/24/2014	$ 1,157,796.00	-
69	24059	32296	T-406-14, L-057A, Test, Discovery Bay	9/26/2014	10/24/2014	$ -	Added as new test from filed replacement project. JE in progress.
70	23644	23644	VA-080 Valve Auto - Hinkley Compressor Station	7/21/2014	10/24/2014	$ -	Additional 2 valves. JE in progress.
71	23731	30881	R-195 L-162A 0.85MI MP 6.62-7.40 REPL PH1	8/8/2014	10/25/2014	$ -	JE in progress.
72	23692	26025	R-048 L-109_4C 1.26MI MP 30.52-31.76 REPL PH1	9/2/2014	10/30/2014	$ -	Project at risk of non-completion in 2014. JE in progress.
73	24900	24900	R-016 L-108_3 2.55MI MP 63.49-65.96 REPL PH1 (partial retirement)	8/18/2014	10/31/2014	$ -	Delayed from 2013 to 2014 due to scheduling and workload balancing. Project at risk of non-completion in 2014. JE in progress.
74	23632	23632	VA-041 Valve Auto - Foley's Ranch Crossover, 6V, PH1 (R-304)	7/23/2014	10/31/2014	$ -	Delayed from 2013 to 2014 to coordinate work with the station rebuild at Foley's Ranch. JE in progress.
75	24052	26049	R-060 L-021D 2.65MI MP 19.27-24.49 REPL PH1	7/24/2014	11/3/2014	$ -	Delayed from 2013 to 2014 due to scheduling and workload balancing. JE in progress.
76	23659	23659	VA-055C Valve Auto - Lakes Valve Lot, 1V, PH1	9/15/2014	11/3/2014	$ -	Delayed from 2013 to 2014 due to efforts related to combining work for scheduling and cost efficiency reasons. JE in progress.
77	24219	30927	T-350-14, L-300B, Test, Hinkley	9/17/2014	11/4/2014	$ -	JE in progress.
78	24072	30898	T-377-14, L-134A, Test, Firebaugh	9/24/2014	11/5/2014	$ -	3,566 ft. is being added to the project to pick up the phase 2 pipe. JE in progress.

TABLE 13-1
PACIFIC GAS AND ELECTRIC COMPANY
PROJECT STATUS SUMMARY - PROJECTS FORECASTED FOR PHASE 1 BUT YET TO START
REPORTING PERIOD JANUARY 1, 2014 – JUNE 30, 2014

Line #	PSEP Filing PSRS	New PSRS	Project Description	Mobilization Date	Tie-in Date	Job Estimate Amount	Comments
79	23704	26516	R-031 L-109_3B_1 1.29MI MP 18.61-19.71 REPL PH1 (partial retirement)	7/23/2014	11/6/2014	$ -	JE in progress
80	#N/A	31059	T-400-14, L-109_4B, Test, Woodside	10/9/2014	11/6/2014	$ -	Added as a new test from a filed replacement project for constructability reasons. 864 ft. added. JE in progress.
81	#N/A	32883	T-407-14, DFM-0206-01, Test, Woodside	10/9/2014	11/6/2014	$ -	New project, PSRS #32883 will be tested in conjunction with strength test on PSRS #31059. For cost efficiency, this project will share a clearance with PSRS# 31059. JE in progress.
82	23636	23636	VA-046 Valve Auto - Dalton Crossover, 2V, PH1	7/7/2014	11/6/2014	$ -	Delayed from 2013 to 2014 in order to coordinate with Non-PSEP ILI Retrofit project (PSRS 24224) at Dalton Crossover for construction efficiency reasons. JE in progress.
83	23599	23599	VA-012 Valve Auto - Lomita Park, 1V, PH1 (S-094)	8/9/2014	11/15/2014	$ -	Scope reduction from 3 to 1 automated valve. JE in progress
84	23634	23634	VA-043 Valve Auto - Irvington, 7V, PH1 L-105N	7/14/2014	11/17/2014	$ -	Delayed from 2013 to 2014 due to the number of other projects currently in progress at Irvington. Design, engineering and permitting activities are targeted to be completed in 2013. JE in progress.
85	23579	23579	T-335A-14, DFM-1502-11, Test, Marysville	10/20/2014	11/21/2014	$ 3,925,193.43	-
86	24219	30928	T-351-14, L-300B, Test, Boron	10/10/2014	11/24/2014	$ -	Project split from filed TEST PSRS 24219. Scope added tested due to constructability/efficiency. JE in progress.
87	23670	23670	VA-065 Valve Auto - Fairfield Crossover 4V, PH1	8/28/2014	11/24/2014	$ -	JE in progress.
88	23736	31368	T-404-14, DFM-0107-01, Test, Oakland	10/15/2014	11/25/2014	$ -	JE in progress
89	23877	33169	R-161 DFM-1815-02 6.46MI MP 6.50-16.85 REPL	8/22/2014	12/4/2014	$ -	Added new replacement project by transferring 1.84 miles from an existing test project due to significant consequences in the event of a test failure.
90	24018	24018	I-065 L-300B MP 299-351.8 ILI & Analysis PH1	8/8/2014	12/10/2014	$ 1,227,440.00	-
91	23692	26023	R-046 L-109_4A_1 2.35MI MP 24.84-27.26 REPL PH1	9/20/2014	12/27/2014	$ -	Projects at risk of non-completion in 2014. JE in progress.
92	23704	27018	R-052 L-109_3C 0.79 MI MP 23.30-24.00 REPL PH1(partial retirement)	3/27/2015	7/31/2015	$ -	Projects at risk of non-completion in 2014. Schedule delayed to 2015. JE in progress.
93	23867	31042	R-188 L-220 0.52MI MP 19.37-19.92 REPL PH1	TBD	TBD	$ -	Delayed from 2013 to 2014 due to permits requiring long lead times. Project delayed to 2015. JE in progress.
94	23692	32307	R-240 L-109_4A_3 0.51MI MP 29.60-31.11 REPL PH1	TBD	TBD	$ -	Project split to reflect pipeline segments that are at risk of non-completion in 2014. Schedule delayed to 2015. JE in progress
95	#N/A	31083	D-047A L-300B MP 359.58 ID-23-1	TBD	TBD	$ -	Added new project to perform validation digs following In-Line Inspection
96	#N/A	31083	D-047B L-300B MP 389.48 ID-23-2	TBD	TBD	$ -	Added new project to perform validation digs following In-Line Inspection
97	23750	31950	R-417 L-021D 0.02MI MP 23.75-24.50 REPL PH1	TBD	TBD	$ -	Added a new project to replace with new 6" pipe to meet qualification for the existing Maximum Allowable Operating Pressure of 313 psig. JE in progress.
98	23718	31974	RT-026 DF3223-DREG3870-NB REPL PH1	TBD	TBD	$ 183,943.72	-
99	23877	32384	T-242B-13, DFM-1815-02, Test, Monterey	TBD	TBD	$ -	-
100	23877	32385	T-243B-13, DFM-1815-02, Test, Monterey	TBD	TBD	$ -	-
101	23706	31845	TS-029-14, GCUST5842, Test, Lathrop	TBD	TBD	$ -	-

TABLE 14-1
PACIFIC GAS AND ELECTRIC COMPANY
PROJECT STATUS SUMMARY - NEW PROJECTS COMPLETED, WORK-IN-PROGRESS, PLANNED
REPORTING PERIOD JANUARY 1, 2014 – JUNE 30, 2014

Line #	PSEP Filing PSRS	New PSRS	Order Number	Project Description	Job Estimate Amount	Comments
1	N/A	29634	30976002	V-085 Valve Auto - L-300A MLV 328.06, 1V, Ph. 1	$ 774,482.00	Added as a new Valve Automation project (originally part of ILI scope) for cost efficiency reasons and to allow for standardization of Valve Automation.
2	N/A	29635	30976003	V-086 Valve Auto - L-300B MLV 327.83, 1V, Ph. 1	$ 728,601.00	Added as a new Valve Automation project (originally part of ILI scope) for cost efficiency reasons and to allow for standardization of Valve Automation.
3	N/A	30094	30984493	V-068A Valve Auto - Airport & Louise, 3V, Ph. 1	$ 2,536,322.00	Added to replace filed Valve Auto project Airport & Yosemite (PSRS 23664) for cost and efficiency reasons due to construction complexities at the filed project site.
4	N/A	32296	42065282	T-406-14, Line L-057A, Discovery Bay	-	Added as new test from filed replacement project. JE in progress.
5	N/A	32860	31056343	V-119 Valve Auto - Davis Meter Reg Station	$ 566,321.00	Added as a new Valve Automation project.
6	N/A	32864	31056341	V-120 Valve Auto - Baseline Rd Lot Rebuild	$ 514,655.00	Added a new Valve Automation project for constructability and efficiency reasons as another project is rebuilding the Baseline Rd Valve Lot. Inclusion of V 3.42, currently a RCV used for system isolation to provide addition feed during high demand periods, in Phase 1 supports wider later Phase 2 Valve Automation program along L-123 which will be adding RCVs from Antelope Meter Sta. (V0.00) to Lincoln Junction (MP 13.57), including Baseline Rd.
7	N/A	32883	42076762	T-407-14, Line DFM-0206-01, Woodside	-	Added new project and is being done in conjunction to filed PSEP project.T-407-14, L-DFM-0206-01 TEST 0.01 MI MP 0.00 to MP 0.01
8	N/A	32950	42072758	T-408-14, Line L-124A, Linda	$ 2,147,183.00	Added new Test - Filed as single REPL, now being done as 3 strength tests. Transfer most of the original replacement project scope to three strength tests due to constructability.
9	N/A	32951	42072761	T-409A-14, Line L-124A, Yuba City	$ 2,236,060.00	Added new Test - Filed as single REPL, now being done as 3 strength tests. Transfer most of the original replacement project scope to three strength tests due to constructability.
10	N/A	32951	42072761	T-409B-14, Line L-124A-1, Yuba City	$ 2,236,060.00	Added new Test - Filed as single REPL, now being done as 3 most of the original replacement project scope to three strength tests due to constructability.
11	N/A	32952	42072763	T-410-14, Line L-124A, Yuba City	$ 2,089,100.00	Added new Test - Filed as single REPL, now being done as 3 most of the original replacement project scope to three strength tests due to constructability.
12	N/A	30894	41913338	T-361-14, L-301B, Test, Prunedale	$ 2,393,812.49	Added new project on L-301B. Identified through data validation by decision tree. (0.63 mile)
13	N/A	32883	42076762	T-407-14, DFM-0206-01, Test, Woodside	-	New project, PSRS #32883 will be tested in conjunction with strength test on PSRS #31059. For cost efficiency, this project will share a clearance with PSRS# 31059. JE in progress.

TABLE 19-1
PACIFIC GAS AND ELECTRIC COMPANY
COST IMPACTS BY PROJECT
REPORTING PERIOD APRIL 1, 2014 – JUNE 30, 2014

Line #	New PSRS	Project Description	Region	Risk	Description	Cost Impact ($)	Schedule Impact (days)	>10% Variance	Comments
1	31693	R-066 L-119B REPL 1.12MI MP 0.59-2.23 PH1	North	Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or incorrect drawings potentially delaying construction and resulting in additional cost.	$543,000	20	No	Change was made to scope from replacement side by side to replacement in place, due to conflicting underground water line and storm drain located during construction. Change extended project duration, clearance and resources needed for replacement.
2	31267	R-199 L-021H REPL 0.06MI MP 6.38-6.42 PH1	Bay	Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or incorrect drawings potentially delaying construction and resulting in additional cost.	$100,000	5	No	Within original trench location and depth we uncovered multiple unknown utility lines passing perpendicularly through the alignment. To maintain minimum clearance from each utility within the proposed depth additional cost was added due to additional pipe and fittings (45° Elbows and 90° Elbows) and labor to excavate, build, x-ray, and coat offsets.
3	31267	R-199 L-021H REPL 0.06MI MP 6.38-6.42 PH1	Bay	Changes After IFB	Any changes to the project scope that were excluded from or occurred after IFB (e.g. additional sniff holes, expanded excavation, added replacement/test length, etc.).	$50,000	2	No	It was not known originally that a drying procedure was going to be required on this new installation. Dewatering pig and nitrogen used for drying.
4	31267	R-199 L-021H REPL 0.06MI MP 6.38-6.42 PH1	Bay	Permitting	Unplanned permitting conditions, requirements and delays from various permitting agencies (e.g. limited working hours, limited access, delays in issuance, etc.).	$25,000	2	No	Due to the fairgrounds scheduling conflicts it was requested for construction crew to mobilize and demobilize off site to accommodate additional fair events from original dates agreed upon, leading to remob cost and schedule delay.
5	29053	R-145 L-306 REPL 0.01MI MP 43.30-43.31 PH1	Central Coast	Clearance	Unplanned permitting conditions, requirements and delays from various permitting agencies (e.g. limited working hours, limited access, delays in issuance, etc.).	$508,664	40	Yes	Due to safety concerns construction team could not meet the original clearances date. GT/GC then backfilled the area for safety and demobed due to schedule/resource constraints, after which an Alliance contractor was brought on to finish work.
6	27904	R-202 DFM-1607-01 REPL 1.11MI MP 0.00-1.62 PH1	Central Coast	Clearance	Tight clearance windows may result in contractor working additional hours to meet the window for tie-in. Delays may also be experienced if a clearance window cannot be obtained when needed due to a variety of reasons. Also, additional labor and/or materials may be necessary to complete clearance.	$600,000	140	Yes	Seven month tie-in delay caused due to cold weather and clearance delay to avoid customer impact.
7	27904	R-202 DFM-1607-01 REPL 1.11MI MP 0.00-1.62 PH2	Central Coast	Differing Site Conditions (DSC): Ground Water	A high water table may be encountered resulting in unplanned dewatering costs and delays in construction.	$2,071,000	10	Yes	Changed construction method to HDD to mitigate groundwater infiltration. Due to ground water near a culvert, a 100ft bore was changed to a 483ft HDD.
8	27904	R-202 DFM-1607-01 REPL 1.11MI MP 0.00-1.62 PH2	Central Coast	Changes After IFB	Any changes to the project scope that were excluded from or occurred after IFB (e.g. additional sniff holes, expanded excavation, added replacement/test length, etc.).	$529,000	-	Yes	Trench realignment due to lack of compaction of existing utilities.
9	27904	R-202 DFM-1607-01 REPL 1.11MI MP 0.00-1.62 PH2	Central Coast	Field Conditions Differ from Expected Conditions	As-built drawings and/or GIS were believed to be accurate according to records, but did not match what was actually encountered in the field.	$211,000	-	Yes	Limited production due to an unmarked gas distribution main and a mismarked Cal water service water main.
10	27904	R-202 DFM-1607-01 REPL 1.11MI MP 0.00-1.62 PH2	Central Coast	Changes After IFB	Any changes to the project scope that were excluded from or occurred after IFB (e.g. additional sniff holes, expanded excavation, added replacement/test length, etc.).	$150,000	-	Yes	Unforeseen tie-in/close-out costs due to uncertainty associated with cost and scope of the demob and site restoration impacted cost.
11	29124	R-230 L-103 REPL 0.01MI MP 22.20-22.21 PH1	Central Coast	Unstable/Weak soil	Unstable soils may require additional shoring which may cause delays to obtain and install.	$44,073	3	Yes	Additional cost and delays were incurred due to digging through slurry backfill. Entire excavation near the MLV which was removed was backfilled with a 2+ sack slurry which made it difficult to dig with backhoe/excavator. Crew used spader to break up slurry.
12	29124	R-230 L-103 REPL 0.01MI MP 22.20-22.21 PH1	Central Coast	Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or incorrect drawings potentially delaying construction and resulting in additional cost.	$35,059	4	Yes	While digging the bypass bellhole, crew discovered 3 conduits, 1 copper line, and 1 steel line. Due to configuration of these lines most of the bellhole had to be hand dug.
13	29124	R-230 L-103 REPL 0.01MI MP 22.20-22.21 PH1	Central Coast	Permitting	Unplanned permitting conditions, requirements and delays from various permitting agencies (e.g. limited working hours, limited access, delays in issuance, etc.).	$19,500	3	Yes	Additional traffic control required, which was not initially reflected in the contract and led to increased cost and schedule delay.
14	29124	R-230 L-103 REPL 0.01MI MP 22.20-22.21 PH1	Central Coast	Permitting	Any changes to the project scope that were excluded from or occurred after IFB (e.g. additional sniff holes, expanded excavation, added replacement/test length, etc.).	$18,324	2	Yes	Delays and cost incurred because of paving concrete roadway per city's specifications. However, the city did not provide a mix design for concrete roadway so contractor had to obtain mix design and have it approved by the city.
15	29124	R-230 L-103 REPL 0.01MI MP 22.20-22.21 PH2	Central Coast	Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or incorrect drawings potentially delaying construction and resulting in additional cost.	$13,413	1	Yes	Due to differing field conditions, the location of the cut and cap on down stream L-103 needed to be moved further away, but close to utility pole. To execute the work safely, additional labor needed to support the pole so we could dig next to it .

TABLE 19-1
PACIFIC GAS AND ELECTRIC COMPANY
COST IMPACTS BY PROJECT
REPORTING PERIOD APRIL 1, 2014 – JUNE 30, 2014

Line #	New PSRS	Project Description	Region	Risk	Description	Cost Impact ($)	Schedule Impact (days)	>10% Variance	Comments
16	29124	R-230 L-103 REPL 0.01MI MP 22.20-22.21 PH1	Central Coast	Field Conditions Differ from Expected Conditions	As-built drawings and/or GIS were believed to be accurate according to records, but did not match what was actually encountered in the field.	$12,566	1	Yes	Unable to cap the 12" bottom-out PCF as planned, required alternate bypass method
17	29124	R-230 L-103 REPL 0.01MI MP 22.20-22.21 PH2	Central Coast	Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or incorrect drawings potentially delaying construction and resulting in additional cost.	$8,765	1	Yes	This abandoned line required removal due to close proximity of existing L-103.
18	23667	VA-067 Valve Auto - Ripon-Modesto, 3V, Ph.1	Central Valley	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or faulty requiring additional work to repair or replace them, including linear indications on the pipe.	$7,302	-	Yes	Coating issues on existing piping required repair thus added to costs.
19	23667	VA-067 Valve Auto - Ripon-Modesto, 3V, Ph.1	Central Valley	Changes After IFB	Any changes to the project scope that were excluded from or occurred after IFB (e.g. additional sniff holes, expanded excavation, added replacement/test length, etc.).	$9,346	-	Yes	Two aprons were added around the man holes at Airport & Louise per request of the engineer. A boom truck obtained to assist GC M&C in setting the actuators led to increased costs.
20	23667	VA-067 Valve Auto - Ripon-Modesto, 3V, Ph.1	Central Valley	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or faulty requiring additional work to repair or replace them, including linear indications on the pipe.	$72,000	17	Yes	Construction complexity led to more work to replace the valves thus resulting in increased costs.
20	23667	VA-067 Valve Auto - Ripon-Modesto, 3V, Ph.1	Central Valley	Material Delivery	The delivery and availability of materials necessary to execute the work may result in schedule and/or cost impacts	$40,000	-	Yes	Actual material cost higher than initially estimated.
21	23667	VA-067 Valve Auto - Ripon-Modesto, 3V, Ph.1	Central Valley	Changes After IFB	Any changes to the project scope that were excluded from or occurred after IFB (e.g. additional sniff holes, expanded excavation, added replacement/test length, etc.).	$7,839	-	Yes	Additional labor costs for as-built survey for the cross tie-in and new valves.
22	23667	VA-067 Valve Auto - Ripon-Modesto, 3V, Ph.1	Central Valley	Clearance	Tight clearance windows may result in contractor working additional hours to meet the window for tie-in. Delays may also be experienced if a clearance window cannot be obtained when needed due to a variety of reasons. Also, additional labor and/or materials may be necessary to complete clearance.	$40,000	-	Yes	Due to complex clearance some additional labor costs were incurred.
25	31771	T-215-13 ,Line L-400,Antioch	Bay	Material Delivery	The delivery and availability of materials necessary to execute the work may result in schedule and/or cost impacts	$9,890	-	Yes	The contractor received the incorrect material onsite resulting in a minor delay. Additional testing and welding were required on the new material ordered.
26	31771	T-215-13 ,Line L-400,Antioch	Bay	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or faulty requiring additional work to repair or replace them, including linear indications on the pipe.	$2,912	-	Yes	Had to remove the asbestos-containing pipe wrap. The scope included abatement coating from exterior of pipe approx. one 2 ft. by 2 ft. spot.
27	31771	T-215-13 ,Line L-400,Antioch	Bay	Changes After IFB	Any changes to the project scope that were excluded from or occurred after IFB (e.g. additional sniff holes, expanded excavation, added replacement/test length, etc.).	$329,000	-	Yes	The initial Calpine bypass design called for an 8" pipeline tapped from L-191. However, Calpine experienced a significant drop in load which required an upsize in pipe. The team recommended that a 16" pipeline will be installed in order to meet the Calpine demands. Additional cost to remove the 8" pipe, provide additional excavation, test the new pipe, fabricate/weld and tie-in the new 16" line.
28	31771	T-215-13 ,Line L-400,Antioch	Bay	Hydrostatic Test Auxillary Leak	Pipe, valves or fittings may be leaking or faulty requiring additional work to repair or replace them, including linear indications on the pipe.	$15,818	-	Yes	The crews encountered a leak along the line as the test couldn't maintain the targeted pressure. The leak was identified at a location within the 8'x12' bell hole. Leaking from the northwest side of the bell hole, it was confirmed that the leak was from the two 36" flanges that connect the dual header. The contractor was directed to excavate and remove the header/flanges to install a straight piece of pipe in order to proceed with testing. In order to meet the schedule, contractor had to work multiple shifts.
29	31771	T-215-13 ,Line L-400,Antioch	Bay	Permitting	Unplanned permitting conditions, requirements and delays from various permitting agencies (e.g. limited working hours, limited access, delays in issuance, etc.).	$27,004	-	Yes	The contractor was not able to discharge until the permit was obtained. These are the additional charges to have the fittings for the "frac" tanks onsite.

TABLE 19-1
PACIFIC GAS AND ELECTRIC COMPANY
COST IMPACTS BY PROJECT
REPORTING PERIOD APRIL 1, 2014 – JUNE 30, 2014

Line #	New PSRS	Project Description	Region	Risk	Description	Cost Impact ($)	Schedule Impact (days)	>10% Variance	Comments
30	31771	T-215-13 ,Line L-400,Antioch	Bay	Weather Impacts	Potential construction delays and resulting additional costs due to rain days. Potential rain interaction with species (e.g. CTS breading migration) delaying construction and increasing cost.	$14,433	-	Yes	Additional "frac" tanks were required due to heavy rain fall, ground water, and pending discharge permits. The contractor was not able to discharge at the time, so extra tanks were needed leading to extra costs.
31	30909	T-379-14, Line L-021F , San Rafael	Bay	Field Conditions Differ from Expected Conditions	As-built drawings and/or GIS were believed to be accurate according to records, but did not match what was actually encountered in the field.	$5,447	-	No	The work to remove the existing electric line in median at a location was not initially identified.
32	30909	T-379-14, Line L-021F , San Rafael	Bay	Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or incorrect drawings potentially delaying construction and resulting in additional cost.	$4,000	-	No	While excavating, a contractor encountered a root ball that had grown around PG&E's pipeline. Contractor utilized a small crew and a vacuum truck to carefully remove the root ball in order to continue with the excavation and the shoring of the excavation.
33	30909	T-379-14, Line L-021F , San Rafael	Bay	Permitting	Unplanned permitting conditions, requirements and delays from various permitting agencies (e.g. limited working hours, limited access, delays in issuance, etc.).	$257,052	-	No	Agreement with the land owner, to fully restore the customer's parking lot which was used as the laydown yard.
34	23471	T-379-14, Line L-021F , San Rafael	Bay	Differing Site Conditions (DSC): Ground Water	A high water table is encountered resulting in unplanned dewatering costs and delays in construction.	$235,000	12	No	Ground water was encountered at 2 ft. An attempt was made to excavate the hole, but trench failures continued due to the soil classification. GC/GT crews demobilized from the project site when contractor installed dewatering wells and a sheet pile coffer dam. The schedule delay associated with the demobilization was 12 days.
35	30907	T-300-14 , LineL-2 , Los Banos	Central Coast	Opportunity: Changes After IFB	Any changes to the project scope that were excluded from or occurred after IFB (e.g. additional sniff holes, expanded excavation, added replacement length, etc.).	($113,942)	-	No	When this project was planned the distance between the PG&E and the adjacent pipeline was not known. As a result the estimate included vacuum truck excavation in case the lines were too close together to excavate mechanically. During construction it was determined the lines were not too close to allow for mechanical excavation so the vac truck was not used in as large a capacity as anticipated. Also the excavation was completed quicker and required less shoring.
36	32184	TS-019-14, Line DREG4388 ,Merced	Central Valley	Field Conditions Differ from Expected Conditions	As-built drawings and/or GIS were believed to be accurate according to records, but did not match what was actually encountered in the field.	$7,711	1.5	No	A weld was required to tie-in piping just above grade, a field determination was agreed upon by all parties that a small excavation would be required to safely perform x-ray and tie-in welding. The excavation at location B was not identified prior to the target pricing, or identified in the construction package thus added to cost increase.
37	32184	TS-019-14, Line DREG4388 ,Merced	Central Valley	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or faulty requiring additional work to repair or replace them, including linear indications on the pipe.	$5,326	1	No	The contractor identified that the filter at location B had been drilled and tapped which was presented to engineering. PLE and Project Engineering requested that the contractor replace the filter which also required additional spool fabrication to complete.
38	32184	TS-019-14, Line DREG4388 ,Merced	Central Valley	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or faulty requiring additional work to repair or replace them, including linear indications on the pipe.	$15,407	5	No	At the request of engineering and T&R, the contractor was directed to dust blast and paint the existing above ground meterset at location B leading to cost increase and schedule overrun.
39	32184	TS-019-14, Line DREG4388 ,Merced	Central Valley	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or faulty requiring additional work to repair or replace them, including linear indications on the pipe.	$5,424	2	No	The existing above ground pipe was missing pipe supports for an approx. 35 ft. span - the Contractor installed concrete supports for it.
40	29426	TS-001-13, Line L-105N-3, Oakland	Bay	Support for other work teams	Unplanned support (equipment or labor) was provided to other teams such as GC, CNG, or LNG because they did not have sufficient resources available at the time that they were needed.	$3,571	-	No	Contractor cleaned-up the project site over and beyond the way they found it during mobilization, in an effort to make T&R's job easier in the future.
41	29426	TS-001-13, Line L-105N-3, Oakland	Bay	Clearance	Additional work or resources may be required to adequately support customer loads during clearance and to meet potentially tight clearance windows.	$8,109	-	No	Contractor incurred standby cost while waiting to receive the cleared line during the clearance process.
42	29426	TS-001-13, Line L-105N-3, Oakland	Bay	Changes After IFB	Any changes to the project scope that were excluded from or occurred after IFB (e.g. additional sniff holes, expanded excavation, added replacement/test length, etc.).	$3,761	-	No	Added a valve box replacement into the scope due to cost saving and constructability.
43	29426	TS-001-13, Line L-105N-3, Oakland	Bay	Hydrostatic Test Auxillary Leak	Pipe, valves or fittings may be leaking or faulty requiring additional work to repair or replace them, including linear indications on the pipe.	$1,764	-	No	Replaced a failed link seal and conducted a casing air test.
44	29426	TS-001-13, Line L-105N-3, Oakland	Bay	Support for other work teams	Unplanned support (equipment or labor) was provided to other teams such as GC, CNG, or LNG because they did not have sufficient resources available at the time that they were needed.	$3,374	-	No	Required extra water tank which added to the cost.

TABLE 19-1
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Line #	New PSRS	Project Description	Region	Risk	Description	Cost Impact ($)	Schedule Impact (days)	>10% Variance	Comments
46	30907	T-300-14, L-2, Test, Los Banos	Central Valley	Opportunity: Mercury Cleaning	Additional cleaning runs beyond what is planned may be required for cleaning mercury from piping prior to strength testing. This includes the requirement to meet drinking water standards of rinse water prior to hydrostatically testing	($100,000)	-	No	Mercury cleaning was planned but not required.
47	30907	T-300-14, L-2, Test, Los Banos	Central Valley	Opportunity: Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or incorrect drawings potentially delaying construction and resulting in additional cost.	($200,000)	-	No	Work was performed very closely with other utilities but careful planning avoided any problems that had been anticipated.
48	30907	T-300-14, L-2, Test, Los Banos	Central Valley	Opportunity: Weather Impacts	Potential construction delays and resulting additional costs due to rain days. Potential rain interaction with species (e.g. CTS breading migration) delaying construction and increasing cost.	($100,000)	-	No	Anticipated weather problems avoided due to good weather during rainy season.
51	30901	T-328-14 T-328-14, Line DFM-1320-01, Fortuna	North	Opportunity: Productivity Impacts - Coordination of work	Coordination/bundling of work can prove to be a cost savings opportunity.	($200,000)	-	No	Shared mob/demob/laydown yard with T-325 and T-326 and led to general productivity gains.
52	30908	T-301-14, L-2, Test, Westley	Central Valley	Changes After IFB	Any changes to the project scope that were excluded from or occurred after IFB (e.g. additional sniff holes, expanded excavation, added replacement length, etc.).	$900,000	-	Yes	Added reg. station test to scope.
53	30908	T-301-14, L-2, Test, Westley	Central Valley	Field Conditions Differ from Expected Conditions	As-built drawings and/or GIS were believed to be accurate according to records, but did not match what was actually encountered in the field.	$100,000	-	Yes	Field conditions required alternate source for water acquisition and discharge.
54	30908	T-301-14, L-2, Test, Westley	Central Valley	Mercury Cleaning	Additional cleaning runs beyond what is planned may be required for cleaning mercury from piping prior to strength testing. This includes the requirement to meet drinking water standards of rinse water prior to hydrostatically testing	$125,000	-	Yes	Unanticipated mercury cleaning. Adjacent line T-300 required no cleaning.
55	32383	T-303A-14, L-186, Test, Dos Palos	Central Valley	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or faulty requiring additional work to repair or replace them, including linear indications on the pipe.	$27,000	-	No	Station conditions required paint and coat.
56	32383	T-303A-14, L-186, Test, Dos Palos	Central Valley	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or faulty requiring additional work to repair or replace them, including linear indications on the pipe.		165	No	Due to deficiencies found in pipe, the project could not be completed in 2013. Thus the job was split into two projects, T-303A and T-303B. T-303B was completed in 2013.
58	30925	T-345B-14, L-197B, Test, Woodbridge	Central Valley	Opportunity: Productivity Impacts - Coordination of work	Coordination/bundling of work can prove to be a cost savings opportunity.	($120,000)	12	No	For cost-efficiency purposes, pushed mobilization by two weeks in order for the same contractor to share resources and crews with project T-303A.
60	23884	T-319-14, DFM-0621-01, Test, Woodland	North	Productivity Impacts	Potential impacts to contractor productivity caused by multiple issues which may result in contractor moving to another construction location on-site or other methods of mitigation.		36	No	The project schedule was shifted prior to mobilization in order to avoid a conflict with Ridgecrest which was using all of PG&E's CNG resources.
61	31843	TS-027-14, GCUST5752, Test, Tracy	Central Valley	Land Acquisition	Difficulty acquiring land due to a variety of complications (e.g. resistant land owners) could result in schedule delays or increased cost (e.g. purchase land, eminent domain)	$120,000	0	No	Needed to acquire land and grade it for lay down area.
62	23665	VA-058 Valve Auto - 24th & 20th Ave, 3V, Ph. 1	North	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or faulty requiring additional work to repair or replace them, including linear indications on the pipe.	$50,000	40	No	Rotork actuators burned out and need replacement.
63	23665	VA-058 Valve Auto - 24th & 20th Ave, 3V, Ph. 1	North	Opportunity: Dewatering	A high water table is encountered resulting in unplanned dewatering costs and delays in construction.	($100,000)	-	No	Dewatering cost were less than anticipated.
65	23579	T-335B-14, DFM-1502-11, Test, Marysville	North	Opportunity: Productivity Impacts	Potential impacts to contractor productivity caused by multiple issues which may result in contractor moving to another construction location on-site or other methods of mitigation.	($100,000)	-	No	GC Distribution crews were working on HPR project in same area, so that project absorbed some of the traffic control and site restoration costs.
66	32050	TS-026-14, X6511, Test, Milpitas	Central Coast	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or faulty requiring additional work to repair or replace them, including linear indications on the pipe.	$50,000	0	No	Pipe jump required extra excavation to remediate.
67	32050	TS-026-14, X6511, Test, Milpitas	Central Coast	Field Conditions Differ from Expected Conditions	As-built drawings and/or GIS were believed to be accurate according to records, but did not match what was actually encountered in the field.	$110,000	0	No	Cement (2 sack) around pipe required additional labor
68	32050	TS-026-14, X6511, Test, Milpitas	Central Coast	Changes after IFB	Any changes to the project scope that were excluded from or occurred after IFB (e.g. additional sniff holes, expanded excavation, added replacement/test length, etc.).	$130,000	1	No	Added scope to test bridle piping adjacent to test site. Bridle had been tested but to a lower pressure

Line #	New PSRS	Project Description	Region	Risk	Description	Cost Impact ($)	Schedule Impact (days)	>10% Variance	Comments
69	31840	TS-022-14, DREG4260, Test, Salinas	Central Coast	Productivity Impacts	Potential impacts to contractor productivity caused by multiple issues which may result in contractor moving to another construction location on-site or other methods of mitigation.	$130,000	6	No	Because of another project (valve) the original clearance could not be met, in addition CNG support made the follow up more complex.
70	31839	TS-032-14, DREG4145, Test, San Jose	Central Coast	Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or incorrect drawings potentially delaying construction and resulting in additional cost.	$50,000	3	Yes	Cemented pipe (2 sack) and numerous adjacent utilities required slower digging and additional labor.
71	31839	TS-032-14, DREG4145, Test, San Jose	Central Coast	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or faulty requiring additional work to repair or replace them, including linear indications on the pipe.	$450,000	18	Yes	Pretest inspection found pipe laminations which required replacement before testing.
72	31839	TS-032-14, DREG4145, Test, San Jose	Central Coast	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or faulty requiring additional work to repair or replace them, including linear indications on the pipe.	$60,000	0	Yes	After construction start, a valve needed replacement.
73	30889	T-375-14, DFM-7226-02, Test, Modesto	Central Valley	Changes after IFB	Any changes to the project scope that were excluded from or occurred after IFB (e.g. additional sniff holes, expanded excavation, added replacement/test length, etc.).	$17,000	0	No	Added bellhole for clearance.
75	23973	VA-077 Valve Auto - Cummings Creek, 1V, Ph. 1	North	Changes after IFB	Any changes to the project scope that were excluded from or occurred after IFB (e.g. additional sniff holes, expanded excavation, added replacement/test length, etc.).	$25,000	0	No	Ground grid needed to meet code.
77	23974	VA-078 Valve Auto - Tompkins Hill, 3V, Ph. 1	North	Changes after IFB	Any changes to the project scope that were excluded from or occurred after IFB (e.g. additional sniff holes, expanded excavation, added replacement/test length, etc.).	$42,000	0	Yes	Ground grid needed to meet code.
78	23974	VA-078 Valve Auto - Tompkins Hill, 3V, Ph. 1	North	Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or incorrect drawings potentially delaying construction and resulting in additional cost.	$20,000	-	Yes	To avoid other underground structures trench was realigned and made deeper.
79	23974	VA-078 Valve Auto - Tompkins Hill, 3V, Ph. 1	North	Field Conditions Differ from Expected Conditions	As-built drawings and/or GIS were believed to be accurate according to records, but did not match what was actually encountered in the field.	$25,000	-	Yes	Because of congestion in valve lot, the welding required extra footage.
80	23974	VA-078 Valve Auto - Tompkins Hill, 3V, Ph. 1	North	Changes After IFB	Any changes to the project scope that were excluded from or occurred after IFB (e.g. additional sniff holes, expanded excavation, added replacement/test length, etc.).	$15,000	-	Yes	Mooney Slam Shut valve was required.
81	23750	RT-001 DF3429-CC REPL PH1	Central Coast	Material Delivery	The delivery and availability of materials necessary to execute the work may result in schedule and/or cost impacts	$28,000	0	Yes	Bill of materials in final estimate was missing some items from preliminary lists. Also a change for clearance and tie-in required extra materials.
82	23750	RT-001 DF3429-CC REPL PH1	Central Coast	Clearance	Additional work or resources may be required to adequately support customer loads during clearance and to meet potentially tight clearance windows.	$100,000	6	Yes	Had originally planned to perform clearance and tie-in on same day, but separated the clearance from the tie-in for safety purposes.
83	31981	RT-032 DREG3759-PN REPL PH1 Expense	Central Coast	Field Conditions Differ from Expected Conditions	As-built drawings and/or GIS were believed to be accurate according to records, but did not match what was actually encountered in the field.	$15,000	2	Yes	Difficulty locating stub from as-builts, required additional site visits and collaboration with corrosion mechanic.
84	31981	RT-032 DREG3759-PN REPL PH1 Expense	Central Coast	Opportunity: Customer Impact	Additional measures may be necessary to appease customer complaints related to construction activities such as noise reduction, additional restoration, etc. and sometimes customer compensation.	$0	12	Yes	Customer requested to accelerate schedule so construction would be complete before Spring Break.
85	30979	TS-015-14, Line GCUST5765, Live Oak	North	Permitting	Unplanned permitting conditions, requirements and delays from various permitting agencies (e.g. limited working hours, limited access, delays in issuance, etc.).	$0	10	No	Delay in obtaining Caltrans Permit.

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86	30979	TS-015-14, Line GCUST5765, Live Oak	North	Customer Impact	Additional measures may be necessary to appease customer complaints related to construction activities such as noise reduction, additional restoration, etc. and sometimes customer compensation.	$0	2	No	Customer requested weekend outage.
87	23928	RT-036 DREG4050-SA REPL PH1	North	Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or incorrect drawings potentially delaying construction and resulting in additional cost.	$5,000	1	Yes	AT&T vault found in alignment. Added time and materials to route around vault.
88	29715	T-358A-14, DFM-6603-01, Test, Ridgecrest	Central Valley	Productivity Impacts	The availability of labor or other resources necessary to execute the work may result in the schedule and/or cost impacts	$343,764	6	No	Because of amount of LNG and CNG support required to execute project, the Bowman LNG site and Armitage CNG site were added.
89	29715	T-358A-14, DFM-6603-01, Test, Ridgecrest	Central Valley	Field Conditions Differ from Expected Conditions	As-built drawings and/or GIS were believed to be accurate according to records, but did not match what was actually encountered in the field.	$29,625	3	No	Pressure control fitting at Feldspar Ave was not at location on the drawings.
90	29715	T-358A-14, DFM-6603-01, Test, Ridgecrest	Central Valley	Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or incorrect drawings potentially delaying construction and resulting in additional cost.	$34,560	3	No	Encountered 23" of concrete on top of pipe in location G which required removal.
91	29715	T-358A-14, DFM-6603-01, Test, Ridgecrest	Central Valley	Material Delivery	The delivery and availability of materials necessary to execute the work may result in schedule and/or cost impacts	$24,200	-	No	Project required pipe be available for contingency purposes and that required extra welding and testing.
92	29715	T-358A-14, DFM-6603-01, Test, Ridgecrest	Central Valley	Permitting	Unplanned permitting conditions, requirements and delays from various permitting agencies (e.g. limited working hours, limited access, delays in issuance, etc.).	$92,160	25	No	Due to permit conditions, the work site was very constricted and caused work to be performed very slowly.

TABLE 20-1
PACIFIC GAS AND ELECTRIC COMPANY
PSEP COSTS, AUTHORIZED AND SHAREHOLDER-FUNDED AMOUNTS BY ACTIVITY

All values in millions of dollars

PSEP Actuals ITD

PSEP Expense	2011	2012	2013	2014 YTD	2014 JAN	2014 FEB	2014 MAR	2014 APR	2014 MAY	2014 JUN	PSEP Costs to Date
Pipeline Modernization											
Pipe Replacement	0.0	0.0	0.1	0.6	0.0	0.0	0.3	0.2	0.1	(0.0)	0.7
In Line Inspection	0.0	0.0	2.4	2.7	0.2	1.3	0.5	0.1	0.0	0.6	5.1
[1] Strength Test											
[5,6] Pre-1955 Installation			125.1	29.3	1.4	1.6	2.6	5.2	9.5	9.0	
[5,6] Post-1955 Installation			33.9	28.5	0.2	1.6	7.0	9.8	2.5	7.5	
Strength Test Total	228.2	130.7	159.0	57.7	1.6	3.1	9.5	15.0	11.9	16.5	575.6
Eng Cond / Fatigue Analysis	0.0	0.0	0.3	0.4	0.0	0.1	0.1	0.0	0.1	0.1	0.7
Pipeline Modernization Total	228.2	130.7	161.9	61.4	1.9	4.5	10.3	15.5	12.1	17.1	582.2
Pipeline Records Integration											
MAOP	90.5	120.3	29.3	0.5	0.1	(0.1)	0.2	0.0	0.1	0.1	240.5
Mariner	1.2	3.8	1.4	1.2	0.1	0.1	0.2	1.3	1.2	(1.7)	7.6
Pipeline Records Integration Total	91.6	124.1	30.7	1.7	0.2	0.1	0.4	1.4	1.3	(1.6)	248.1
Valve Automation	0.0	0.5	1.9	1.0	0.1	0.2	0.1	0.2	0.4	0.1	3.4
Interim Safety Measures	0.0	2.4	2.3	0.5	0.0	0.0	0.2	0.0	0.1	0.1	5.2
PMO	5.0	6.5	3.5	2.5	1.1	0.7	(0.4)	0.2	0.5	0.3	17.5
Other	6.8	6.3	5.2	3.7	0.2	1.0	(1.3)	2.4	(0.3)	1.6	22.0
Total PSEP Expense	331.7	270.4	205.4	70.9	3.5	6.6	9.3	19.7	14.2	17.6	878.4
PSEP Capital											
Pipeline Modernization											
[1] Pipeline Replacement											
[5,7] Pipeline Replacement less Post-195	11.9	224.1	307.5	65.8	11.2	8.4	10.6	7.1	13.0	15.5	609.3
[7] Retirements	0.0	0.6	4.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	4.7
[7] Downgrades	0.0	1.5	(1.5)	0.0	0.0	(0.0)	(0.0)	0.0	0.0	(0.0)	0.1
[5] Post-1955 Strength Test Cost	0.0	2.1	2.2	5.8	0.0	1.8	1.5	0.0	0.7	1.8	10.0
Pipeline Replacement Total	11.89	228.36	312.26	71.63	11.23	10.15	12.13	7.16	13.71	17.26	624.1
Strength Test Related	5.9	12.3	28.8	6.5	0.1	0.2	1.1	1.6	0.9	2.6	53.5
In Line Inspection Retrofitting	0.6	16.0	36.8	3.6	1.7	1.1	0.8	(0.2)	0.2	0.0	57.0
Pipeline Modernization Total	18.4	256.7	377.8	81.8	13.0	11.5	14.1	8.6	14.8	19.9	734.6
Pipeline Records Integration											
MAOP	1.7	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9
Mariner	4.9	29.3	37.1	12.6	2.0	1.8	2.9	1.6	1.6	2.7	83.9
Pipeline Records Integration Total	6.5	29.6	37.1	12.6	2.0	1.8	2.9	1.6	1.6	2.7	85.9
[1] Valve Automation	13.0	29.5	51.9	23.2	2.0	2.6	5.2	4.9	5.3	3.1	117.6
Interim Safety Measures	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PMO	2.3	2.1	8.8	3.3	0.0	0.0	1.4	0.9	0.4	0.6	16.4
Other	0.0	3.0	0.0	0.2	0.6	0.3	0.3	0.8	(1.8)	(0.0)	3.2
Total PSEP Capital	40.2	320.8	475.7	121.1	17.7	16.3	23.8	16.8	20.4	26.2	957.8

Authorized[2] / **Update Application[3]**

PSEP Expense	2011-2014 PSEP Authorized	2011 Authorized	2012 Authorized	2013 Authorized	2014 Authorized	2011-2014 PSEP Updated	2011 Updated	2012 Updated	2013 Updated	2014 Updated
Pipeline Modernization										
Pipe Replacement										
In Line Inspection										
[1] Strength Test										
[5,6] Pre-1955 Installation										
[5,6] Post-1955 Installation										
Strength Test Total										
Eng Cond / Fatigue Analysis										
Pipeline Modernization Total	149.5	0.0	2.3	65.9	81.2	118.3	0.0	2.3	62.3	53.6
Pipeline Records Integration										
MAOP										
Mariner										
Pipeline Records Integration Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Valve Automation	6.7	0.0	0.1	3.0	3.6	6.7	0.0	0.1	3.0	3.6
Interim Safety Measures	2.1	0.0	0.0	1.0	1.0	2.1	0.0	0.0	1.1	1.0
PMO	6.6	0.0	0.1	3.3	3.2	6.6	0.0	0.1	3.3	3.2
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total PSEP Expense	164.9	0.0	2.5	73.3	89.1	133.7	0.0	2.5	69.7	61.4
PSEP Capital										
Pipeline Modernization										
[1] Pipeline Replacement										
[5,7] Pipeline Replacement less Post-195										
[7] Retirements										
[7] Downgrades										
[5] Post-1955 Strength Test Cost										
Pipeline Replacement Total										
Strength Test Related										
In Line Inspection Retrofitting										
Pipeline Modernization Total	852.5	30.5	214.7	290.1	317.0	614.9	25.3	148.6	296.0	145.0
Pipeline Records Integration										
MAOP										
Mariner										
Pipeline Records Integration Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
[1] Valve Automation	129.0	13.7	38.9	51.6	24.8	129.0	13.7	38.9	51.6	24.8
Interim Safety Measures	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PMO	22.3	3.0	6.5	6.5	6.3	22.3	3.0	6.5	6.5	6.3
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total PSEP Capital	1003.8	47.2	260.1	348.2	348.0	766.2	42.0	194.0	354.1	176.1

Shareholder Funded per Update Application[4]

PSEP Expense	ITD Shareholder Funded	2011	2012	2013	2014 YTD	2014 JAN	2014 FEB	2014 MAR	2014 APR	2014 MAY	2014 JUN
Pipeline Modernization											
Pipe Replacement											
In Line Inspection											
[1] Strength Test											
[5,6] Pre-1955 Installation											
[5,6] Post-1955 Installation											
Strength Test Total											
Eng Cond / Fatigue Analysis											
Pipeline Modernization Total	490.7	228.2	128.4	99.5	34.6	(2.6)	0.0	5.8	11.0	7.7	12.6
Pipeline Records Integration											
MAOP											
Mariner											
Pipeline Records Integration Total	248.1	91.6	124.1	30.7	1.7	0.2	0.1	0.4	1.4	1.3	(1.6)
Valve Automation	(0.4)	0.0	0.4	(1.1)	0.3	0.0	0.0	0.1	0.1	0.0	0.1
Interim Safety Measures	3.6	0.0	2.4	1.2	(0.0)	(0.1)	(0.0)	0.1	(0.1)	0.0	0.1
PMO	12.5	5.0	6.4	0.2	0.9	0.8	0.4	(0.6)	(0.0)	0.2	0.1
Other	22.0	6.8	6.3	5.2	3.7	0.2	1.0	(1.3)	2.4	(0.3)	1.6
Total PSEP Expense	776.5	331.7	267.9	135.7	41.2	(1.4)	1.6	4.4	14.8	9.0	12.8
PSEP Capital											
Pipeline Modernization											
[1] Pipeline Replacement											
[5,7] Pipeline Replacement less Post-195											
[7] Retirements											
[7] Downgrades											
[5] Post-1955 Strength Test Cost											
Pipeline Replacement Total											
Strength Test Related											
In Line Inspection Retrofitting											
Pipeline Modernization Total	119.7	0.0	2.1	35.9	81.8	13.0	11.5	14.1	8.6	14.8	19.9
Pipeline Records Integration											
MAOP											
Mariner											
Pipeline Records Integration Total	85.9	6.5	29.6	37.1	12.6	2.0	1.8	2.9	1.6	1.6	2.7
[1] Valve Automation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Interim Safety Measures	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PMO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	3.2	0.0	3.0	0.0	0.2	0.6	0.3	0.3	0.8	(1.8)	(0.0)
Total PSEP Capital	208.9	6.5	34.6	73.0	94.7	15.6	13.6	17.2	11.0	14.6	22.6

[1] StanPac included in Actual and Forecasted Costs and Authorized Recovery
[2] Authorized Amount from D-12.12.030
[3] Update Application includes October 2013 Updated Recovery to the Pipe Modernization Program; Does not include Settlement Agreement
[4] Shareholder Funded Portion has been updated to reflect revenue numbers consistent with the Update Application
[5] Pre/Post 1955 spend has been updated based on MAOP Validation
[6] Net change to Q4 2013 Compliance Report of zero. However, a +/-shift of $245k to post/pre 1955 Strength Test in actuals of Dec 2013
[7] Includes 7.79 miles (5 orders) of projects that are 100% retired and 8.80 miles (3 orders) of projects that 100% downgrades. We are unable to allocate the actual recorded costs for the remaining retirements and downgrades that were part of a larger replacement project. Dollar values for these specific projects were determined through a pull of the financial system and subtracted from the overall Pipe Replacement spend to determine the Pipe Replacement less Post-1955 Strength Test Costs. 6/7th of the StanPac project was included in the total for Retirement.

TABLE 22-2
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL MILEAGE OF PIPE REPLACED - FORECASTED AND ACTUAL
JANUARY 1, 2014 – JUNE 30, 2014

Line #	PSEP Filing PSRS	New PSRS	Project Description	Miles Completed	Installed	Retired	Downrated	Line	MP1	MP2	City	HCA	Class Code	Clearance Date	Tie-in Date
1	#N/A	26041	R-056 L-220 4.93MI MP 20.84-31.65 REPL PH1	4.93	4.93	0.00	0.00	L-220	20.84	31.65	Davis	Yes	1,2,3,SPLIT	12-Nov-13	10-Jan-14
2	#N/A	29247	R-037 L-172A 3.06MI MP 75.43-78.53 REPL PH1	3.07	3.06	0.01	0.00	L-172A	75.43	78.53	West Sacramento	Yes	3,SPLIT	21-Jan-14	31-Jan-14
3	#N/A	23888	R-109 L-116 0.04MI MP 0.00-0.03 REPL PH1	0.04	0.00	0.04	0.00	L-116	0	0.03	Davis	Yes	3,SPLIT	N/A	5-Feb-14
4	#N/A	23930	R-111 DFM-0627-01 0.01MI MP 0.00-0.02 REPL PH1	0.02	0.02	0.00	0.00	DFM-0627-01	0	0.02	Davis	Yes	3,SPLIT	N/A	5-Feb-14
5	#N/A	29275	R-157 DFM-1603-01 1.42MI MP 0.07-1.30 REPL PH1	1.40	1.40	0.00	0.00	DFM-1603-01	0.07	1.3	Lathrop	Yes	3,SPLIT	12-Mar-14	14-Mar-14
6	#N/A	31822	R-207 L-177A 0.01MI MP 26.55-26.55 REPL PH1	0.00	0.00	0.00	0.00	L-177A	26.55	26.55	Corning	Yes	2	19-Mar-14	20-Mar-14
7	#N/A	29053	R-145 L-306 0.01MI MP 43.30-43.31 REPL PH1	0.01	0.01	0.00	0.00	L-306	43.3	43.31	Paso Robles	No	3	13-May-14	14-May-14
8	#N/A	27904	R-202 DFM-1607-01 1.11MI MP 0.00-1.62 REPL PH1	1.11	1.11	0.00	0.00	DFM-1607-01	0	1.62	Stockton	Yes	3,SPLIT	20-May-14	20-May-14
9	23728	29124	R-230 L-103 0.01MI MP 22.20-22.21 REPL PH1	0.01	0.01	0.00	0.00	L-103	22.2	22.21	Salinas	Yes	3	30-Apr-14	22-May-14
10	24055	31267	R-199 L-021H 0.06MI MP 6.38-6.42 REPL PH1	0.05	0.05	0.00	0.00	L-021H	6.38	6.42	Vallejo	Yes	3	9-May-14	4-Jun-14
11	#N/A	31693	R-066 L-119B 1.12MI MP 0.59-2.23 REPL PH1	1.18	1.18	0.00	0.00	L-119B	0.59	2.23	Sacramento	Yes	3	16-May-14	5-Jun-14
12	#N/A	31978	RT-029 DREG5483-NV REPL PH1	0.03	0.03	0.00	0.00	DREG5483	N/A	N/A	Redding	No	3	21-Jan-14	21-Jan-14
13	#N/A	31970	RT-022 DREG4873-MI REPL PH1	0.01	0.01	0.00	0.00	DREG4873	N/A	N/A	San Leandro	No	3	24-Jan-14	24-Jan-14
14	#N/A	32001	RT-046 STUB6041-SI REPL PH1	0.00	0.00	0.00	0.00	STUB6041	N/A	N/A	Live Oak	No	3	24-Jan-14	24-Jan-14
15	#N/A	31998	RT-043 DREG4548-SI REPL PH1	0.00	0.00	0.00	0.00	DREG4548	N/A	N/A	Yuba City	No	3	13-Feb-14	13-Feb-14
16	#N/A	31993	RT-047 DCUST2473-SJ REPL PH1	0.01	0.01	0.00	0.00	DCUST2473	N/A	N/A	Morgan Hill	No	3,SPLIT	20-Feb-14	20-Feb-14
17	#N/A	31999	RT-044 DREG4567-SI REPL PH1	0.01	0.01	0.00	0.00	DREG4567	N/A	N/A	Wheatland	No	3	24-Feb-14	24-Feb-14
18	#N/A	31971	RT-023 GCUST5901-MI REPL PH1	0.05	0.05	0.00	0.00	GCUST5901	N/A	N/A	San Leandro	Yes	3	5-Mar-14	5-Mar-14
19	#N/A	31979	RT-030 STUB8663-STUB8664-STUB8665-NV REPL PH1	0.00	0.00	0.00	0.00	STUB8663	N/A	N/A	Gridley	Yes	3	7-Mar-14	8-Mar-14
20	#N/A	31969	RT-021 DREG4872-MI REPL PH1	0.01	0.01	0.00	0.00	DREG4872	N/A	N/A	San Lorenzo	No	3	14-Mar-14	14-Mar-14
21	#N/A	32012	RT-061 DREG4420-YO REPL PH1	0.02	0.02	0.00	0.00	DREG4420	N/A	N/A	Madera	No	3	17-Mar-14	17-Mar-14
22	#N/A	32000	RT-045 STUB6039-SI REPL PH1	0.00	0.00	0.00	0.00	STUB6039	N/A	N/A	Live Oak	No	3	18-Mar-14	18-Mar-14
23	#N/A	31951	RT-004 DREG5148-CC REPL PH1	0.01	0.01	0.00	0.00	DREG5148	N/A	N/A	Santa Cruz	No	3	27-Mar-14	27-Mar-14
24	#N/A	33217	RT-010 STUB9046-DI REPL PH1	0.00	0.00	0.00	0.00	STUB9046	N/A	N/A	Brentwood	No	3	26-Mar-14	28-Mar-14
25	#N/A	31981	RT-032 DREG3759-PN REPL PH1 Expense	0.00	0.00	0.00	0.00	DREG3759	N/A	N/A	Half Moon Bay	No	3,SPLIT	15-Apr-14	15-Apr-14
26	23928	31988	RT-039 STUB8028-SA REPL PH1	0.00	0.00	0.00	0.00	STUB8028	N/A	N/A	Woodland	No	3	23-Apr-14	23-Apr-14
27	23690	31961	RT-014 DREG4794-FR REPL PH1	0.01	0.01	0.00	0.00	DREG4794	N/A	N/A	Fresno	No	3,SPLIT	6-Jun-14	6-Jun-14
28	23928	31985	RT-036 DREG4050-SA REPL PH1	0.01	0.01	0.00	0.00	DREG4050	N/A	N/A	Sacramento	No	3	31-May-14	7-Jun-14
29	23750	31948	RT-001 DF3429-CC REPL PH1	0.00	0.00	0.00	0.00	DF3429	N/A	N/A	Santa Cruz	Yes	3	16-Jun-14	24-Jun-14

TABLE 23-2
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL MILEAGE OF PIPE STRENGTH TESTED - FORECASTED AND ACTUAL
JANUARY 1, 2014 – JUNE 30, 2014

Line #	PSEP Filing PSRS	New PSRS	Project Description	Miles Completed	Line	MP1	MP2	City	HCA	Class Code	Clearance Date	Tie-in Date
1	#N/A	30907	T-300-14, L-2, Test, Los Banos	0.88	L-002	75.60	76.46	Los Banos	Yes	1	24-Feb-14	11-Mar-14
2	#N/A	31771	T-215-13, L-400, Test, Oakley	0.98	L-400	297.84	298.84	Oakley	Yes	3	12-Mar-14	26-Mar-14
3	#N/A	31369	T-405-14, DFM-1209-01, Test, Fowler	0.79	DFM-1209-01	4.15	4.94	Fowler	No	3	25-Mar-14	2-Apr-14
4	#N/A	30908	T-301-14, L-2, Test, Westley	3.71	L-002	118.29	121.99	Westley	No	1	3-Apr-14	28-Apr-14
5	#N/A	32882	T-358B-14, DREG5496, Test, Ridgecrest	0.30	DREG5496	1.17	1.47	Ridgecrest	No	3,SPLIT	9-Apr-14	5-May-14
6	#N/A	30909	T-379-14, L-021F, Test, San Rafael	0.79	L-021F	18.00	18.79	San Rafael	Yes	3	14-Apr-14	5-May-14
7	#N/A	23471	T-235-13, L-131Z, Test, Rio Vista	0.54	L-131Z	0.00	0.55	Rio Vista	No	3	21-Mar-14	6-May-14
8	23895	31054	T-348-14, DFM-2408-01, Test, Livermore	0.40	DFM-2408-01	2.32	2.72	Livermore	No	1,3	3-May-14	12-May-14
9	23481	30889	T-375-14, DFM-7226-02, Test, Modesto	0.37	DFM-7226-02	0.28	0.65	Modesto	No	3	5-May-14	13-May-14
10	#N/A	30901	T-328-14, DFM-1310-01, Test, Fortuna	1.29	DFM-1310-01	0.00	1.29	Fortuna	No	1,2,3	12-May-14	14-May-14
11	23912	30945	T-332A-14, DFM-1501-02, Test, Yuba City	0.97	DFM-1501-02	0.00	0.97	Yuba City	Yes	3	1-May-14	20-May-14
12	#N/A	29715	T-358A-14, DFM-6603-01, Test, Ridgecrest	6.15	DFM-6603-01	0.00	6.16	Ridgecrest	Yes	3	12-Apr-14	22-May-14
13	#N/A	23579	T-335B-14, DFM-1502-11, Test, Marysville	1.58	DFM-1502-11	1.38	2.96	Marysville	No	2	12-May-14	27-May-14
14	23520	30925	T-345B-14, L-197B, Test, Woodbridge	0.78	L-197B	4.71	5.49	Woodbridge	No	2,3	8-May-14	4-Jun-14
15	23884	23884	T-319-14, DFM-0621-01, Test, Woodland	0.68	DFM-0621-01	0.02	0.70	Woodland	No	3	24-May-14	13-Jun-14
16	#N/A	32383	T-303A-14, L-186, Test, Dos Palos	1.19	L-186	8.94	10.14	Dos Palos	Yes	1,3,SPLIT	2-Jun-14	18-Jun-14
17	23912	30946	T-332B-14, DFM-1501-02, Test, Yuba City	2.63	DFM-1501-02	1.92	4.26	Yuba City	Yes	3	13-Jun-14	30-Jun-14
18	23911	31370	T-368-14, DFM-1501-01, Test, Yuba City	1.16	DFM-1501-01	5.76	6.88	Yuba City	No	2	9-Jun-14	30-Jun-14
19	#N/A	31837	TS-025-14, DCUST1614, Test, Marysville	0.22	DCUST1614	0.00	0.22	Marysville	No	2,SPLIT	18-Feb-14	26-Feb-14
20	23787	30979	TS-015-14, GCUST5765, Test, Live Oak	0.09	GCUST5765	0.00	0.09	Live Oak	Yes	2,3	11-Apr-14	14-Apr-14
21	#N/A	29426	TS-001-13, L-105N-3, Test, Oakland	0.03	L-105N-3	0.05	0.08	Oakland	Yes	3	12-Apr-14	16-Apr-14
22	#N/A	32184	TS-019-14, DREG4388, Test, Merced	0.07	DREG4388	0.00	0.07	Merced	Yes	3,SPLIT	7-Apr-14	16-Apr-14
23	#N/A	31840	TS-022-14, DREG4260, Test, Salinas	0.70	DREG4260	0.08	0.78	Salinas	No	3,SPLIT	17-Apr-14	24-Apr-14
24	#N/A	31839	TS-032-14, DREG4145, Test, San Jose	0.14	DREG4145	0.00	0.14	San Jose	No	3,SPLIT	23-Apr-14	26-Apr-14
25	#N/A	32050	TS-026-14, X6511, Test, Milpitas	0.13	X6511	0.00	0.13	Milpitas	Yes	3,SPLIT	9-Jun-14	25-Jun-14
26	#N/A	31843	TS-027-14, GCUST5752, Test, Tracy	0.80	GCUST5752	0.00	0.77	Tracy	No	3,SPLIT	24-Jun-14	28-Jun-14

TABLE 25-1
PACIFIC GAS AND ELECTRIC COMPANY
COMPLETED VALVE AUTOMATION AND IN-LINE INSPECTION PROJECTS
JANUARY 1, 2014 – JUNE 30, 2014

Line #	PSEP Filing PSRS	New PSRS	Project Description	Miles Completed / Valves Automated	Line	MP1	MP2	City	HCA	Class Code	Clearance Date	Tie-in Date
1	#N/A	24009	I-001 L-131 MP 50.5-57.4 Upgrade PH1	6.7	L-131	50.5	57.4	Fremont	Yes	3	10-Apr-13	15-Jan-14
2	#N/A	23597	VA-010 Valve Auto - Commercial Way, 3V, PH1	3	L-101	N/A	N/A	San Carlos	N/A	N/A	27-Jun-13	24-Jan-14
3	#N/A	30094	VA-068A Valve Auto - Airport & Louise, 3V, PH1	3	L-108	N/A	N/A	Manteca	N/A	N/A	N/A	27-Jan-14
4	#N/A	32860	VA-119 Valve Auto - Davis Meter Reg Station	1	DFM-1622-01	N/A	N/A	Sacramento	N/A	N/A	11-Jan-14	5-Feb-14
5	#N/A	31601	D-009 L-300A MP 235.55 CD-06A	1	L-300A	235.55	N/A	Kern	N/A	N/A	N/A	6-Feb-14
6	#N/A	30070	D-014A L-300A MP 354.35 ID-18-1	1	L-300A	354.35	N/A	Kettleman City	N/A	N/A	N/A	24-Feb-14
7	#N/A	30070	D-014C L-300A MP 372.97 ID-18-3	1	L-300A	372.97	N/A	Coalinga	N/A	N/A	N/A	24-Feb-14
8	#N/A	24027	I-060 L-101(S) MP 0.00-11.62 ILI & Analysis PH1	12.08	L-101	0	11.85	Milpitas	Yes	1,3	19-Feb-14	1-Mar-14
9	#N/A	30070	D-014B L-300A MP 369.72 ID-18-2	1	L-300A	369.72	N/A	Coalinga	N/A	N/A	N/A	17-Mar-14
10	#N/A	29634	VA-085 Valve Auto - L-300A MLV 328.06, 1V, PH1	1	L-300A	N/A	N/A	Fresno	N/A	N/A	N/A	3-Apr-14
11	#N/A	29635	VA-086 Valve Auto - L-300B MLV 327.83, 1V, PH1	1	L-300B	N/A	N/A	Fresno	N/A	N/A	N/A	11-Apr-14
12	#N/A	23973	VA-077 Valve Auto - Cummings Creek, 1V, PH1	1	L-177A	N/A	N/A	Fortuna	N/A	N/A	11-Apr-14	16-Apr-14
13	#N/A	23974	VA-078 Valve Auto - Tompkins Hill, 3V, PH1	3	L-126A	N/A	N/A	Fortuna	N/A	N/A	23-Apr-14	8-May-14
14	#N/A	23667	VA-067 Valve Auto - Ripon-Modesto, 3V, PH1	3	L-108	N/A	N/A	Manteca	N/A	N/A	14-Apr-14	30-May-14
15	#N/A	23650	VA-075 Valve Auto - Gosford Rd Mtr Sta, 3V, PH1	3	L-300B	N/A	N/A	Bakersfield	N/A	N/A	N/A	4-Jun-14
16	#N/A	23652	VA-074 Valve Auto - Union Ave Meter Reg Sta, 1V, PH1	1	L-300B	N/A	N/A	Bakersfield	N/A	N/A	N/A	5-Jun-14
17	#N/A	23665	VA-058 Valve Auto - 24th & 20th Ave, 3V, PH1	3	L-108	N/A	N/A	Sacramento	N/A	N/A	N/A	26-Jun-14

TABLE 26-1
PACIFIC GAS AND ELECTRIC COMPANY
FORECAST PROJECTS NOT COMPLETED OR REPLACED BY HIGHER PRIORITY PROJECTS
REPORTING PERIOD APRIL 1, 2014 – JUNE 30, 2014

Line #	PSEP Filing PSRS	New PSRS	Project Description	PSEP Filing Year	Current Status	Comments
1	24077	30790	L-108 1B REPL 0.05MI MP 38.17-38.22 PH1	2013	Removed	PSRS 30790 removed from PSEP because Segment 145-1 will be addressed by a base-funded replacement project (PSRS 18025).