Application of Southern California Gas Company for authority to update its gas revenue requirement and base rates effective on January 1, 2012. (U904G)

Application 10-12-___
Exhibit No.: (SCG-05)

PREPARED DIRECT TESTIMONY OF
RAYMOND K. STANFORD
ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

DECEMBER 2010

The Gas Company

SCG Doc#250042

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PREPARED DIRECT TESTIMONY OF

RAYMOND K. STANFORD

ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY

(GAS ENGINEERING)

I. INTRODUCTION

A. Purpose of Testimony

The purpose of my testimony is to demonstrate that the Southern California Gas Company (SoCalGas or Company) forecast for Operations and Maintenance (O&M) and capital expenditures are reasonable; therefore, they should be adopted by the California Public Utilities Commission (CPUC or Commission).

Expenditures discussed in this chapter are as follows:

- O&M Expenditures for Gas Engineering in support of Distribution, Transmission, and Storage Operations;
- O&M Expenditures to comply with Pipeline Integrity requirements for Transmission and Distribution;
- O&M Expenditures to comply with Public Awareness evaluation requirements;
- O&M Expenditures to comply with Environmental and Air Quality requirements;
- O&M Expenditures to implement the Sustainable SoCal Program;
- Capital Expenditures for Gas Engineering and Transmission Operations; and
- Capital Expenditures to implement the Sustainable SoCal Program.
- SoCalGas' forecasts are responsive to its philosophy of achieving operational excellence while judiciously balancing the following corporate tenets:
- To provide safe and reliable delivery of natural gas;
- To meet regulatory obligations;
- To leverage expertise whenever possible to meet the challenge of a maturing workforce; and
- To balance these demands while delivering natural gas at the lowest cost possible.

This testimony includes Gas Engineering's non-shared and shared expenses in support of day-to-day functions for gas transmission and storage; distribution mains and services; and measurement and regulator stations. Capital expenditures are in support of the installation and replacement of the transmission infrastructure to sustain a safe and reliable system. Also presented in this testimony are the Distribution capital expenditures related to pipeline integrity. Finally, this testimony describes anticipated changes in operations, explains the basis for these changes, and provides projections for the resulting changes in expenditures.

In total, SoCalGas is requesting the Commission adopt SoCalGas' Test Year 2012 (TY 2012) forecast of $94,452,000 ($2009) for Gas Engineering O&M expenses, which is composed of $78,399,000 for non-shared service activities and $16,053,000 for shared service activities. SoCalGas is also requesting the Commission adopt its TY 2012 forecast of $158,306,000 for capital expenditures. A summary of the overall request is presented in Table SCG-RKS-1; all costs in this testimony are shown in 2009 dollars, unless otherwise noted.

TABLE SCG-RKS -1
Summary of TY 2012 Change
(Thousands of 2009 dollars)

Functional Area: ENGINEERING				
Description	**2009 Adjusted-Recorded**	**TY2012 Estimated**	**Change**	**Testimony Reference**
Total Non-Shared	28,027	78,399	50,372	**Section II**
Total Shared Services (Book Expense)	12,377	16,053	3,676	**Section III**
Total O&M	**40,404**	**94,452**	**54,048**	
Total Capital	**85,939**	**158,306**	**72,367**	**Section IV**

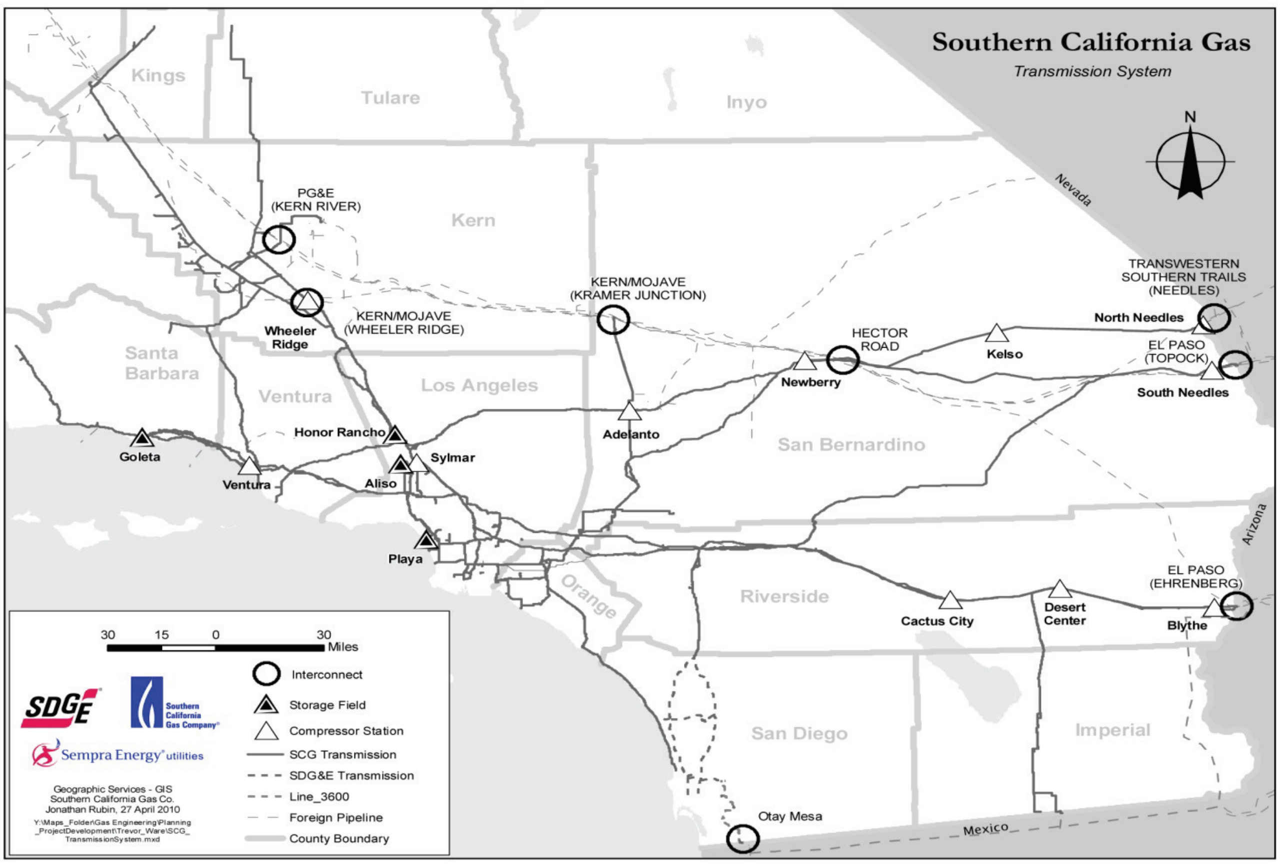
B. Overview of Operations

SoCalGas' Natural Gas Transportation System

SoCalGas' transmission system spans from the California–Arizona border to the Pacific Ocean and from the California–Mexico border to Fresno County. Transmission facilities are operated in the counties of San Bernardino, Riverside, Imperial, Orange, Los Angeles, Ventura, Santa Barbara, Kern, Tulare, Kings, San Luis Obispo, and San Diego.

The transmission system is comprised of 2,830 miles of transmission pipeline and 11 compressor stations. The system is designed to receive natural gas from interstate pipelines and various California production sources from both offshore and onshore. The gas quantity is measured, analyzed for quality, and then allowed to flow through the pipeline network. This pipeline-quality gas is delivered to the Company's distribution system, storage fields, and non-core customers. For clarification, the 2,830 miles of transmission pipeline refers to the length of transmission pipeline operated by the Gas Transmission organization. The Department of Transportation (DOT) utilizes engineering criteria to define the term "transmission line" in the federal pipeline safety regulations (49 CFR § 192.3 "Definitions"). Using the DOT definition, SoCalGas' distribution, transmission, and storage operating units collectively operate approximately 3,989 miles of "DOT transmission pipeline", with approximately 1,140 miles of "DOT transmission pipeline" maintained and operated by the Distribution Operations organization. This testimony includes the costs associated with transmission integrity management for SoCalGas' DOT-defined transmission lines, regardless if Distribution Operations or Gas Transmission operates them.

Figure SCG-RKS-1



The capacity of a storage field is measured in 'billion cubic feet', or Bcf. SoCalGas operates four underground storage fields with a working inventory capacity of approximately 134 Bcf. These fields are Aliso Canyon - 86 Bcf, La Goleta – 21.5 Bcf, Honor Rancho 24.1 -

Bcf, and Playa del Rey – 2.4 Bcf. These storage facilities are an integral part of the energy infrastructure required to provide southern California residents and businesses with safe, reliable, and cost-effective energy services.

The distribution system is comprised of approximately 47,600 miles of mains, 4.35 million services, and 5.7 million meters[1]. Also included are 1,140 miles of DOT-defined transmission pipelines operated by Distribution. SoCalGas is the largest natural gas distribution operation in the United States based on miles of mains and number of services.[2]

Collectively, these components enable SoCalGas to deliver natural gas from receipt point to burner tip reliably and safely. In order to continue to provide safe and reliable service, SoCalGas must continue to make prudent investments in its infrastructure pursuant to applicable regulatory requirements. Furthermore, much of the projected costs is in direct response to mandated federal pipeline safety regulations including, but not limited to, requirements associated with 49 C.F.R. § 192.901 Subpart O "Gas Transmission Pipeline Integrity Management" (herein referred to as the Transmission Integrity Management Program, or TIMP) and 49 C.F.R. § 192.1001 Subpart P "Gas Distribution Pipeline Integrity Management" (herein referred to as the Distribution Integrity Management Program, or DIMP). The requested funding includes the costs of complying with mandated pipeline safety regulations as well as providing the necessary resources to sustain SoCalGas' critical energy infrastructure.

C. Challenges Facing Operations

This section of the testimony provides an overview of the challenges facing SoCalGas' operations as well as a clearer picture as to some of the variables facing SoCalGas and the industry as a whole.

Discussing these challenges is important because it provides the foundation to better understand SoCalGas' approach in addressing them. Some of the most significant challenges are rooted in the mandates issued by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) related to pipeline integrity

[1] www.socalgas.com/aboutus/profile.html.
[2] Ranking based upon DOT's 2009 report of mains and services found at http://ops.dot.gov/stats/DT98.htm.

management, and at the state level with legislative requirements on Greenhouse Gases (GHGs).

The challenges associated with federal mandates are two-fold. One is the amount of work they require, and the second is the type of work required. The DOT regulations related to the pipeline integrity management programs contain extensive requirements that translate to challenges in addressing the overall scope of the work required as well as the scheduling and performance of the individual elements, due in part to the size of the SoCalGas system.

These two pipeline integrity management programs are TIMP and DIMP.

<u>Pipeline Integrity—Transmission (TIMP)</u>

In line with Section 14 of the Pipeline Safety Improvement Act of 2002 (PSIA), PHMSA issued regulations mandating integrity management programs for natural gas transmission pipelines[3]. These regulations require a two-step approach to evaluate and monitor an operator's transmission pipeline system. The first step is the initial inspection. The initial integrity inspection is called a "baseline assessment." The second is a re-occurring inspection called a "reassessment inspection," or simply a "reassessment." SoCalGas developed and implemented its integrity management program in accordance with the requirements contained in 49 C.F.R. § 192.901, Subpart O –"Gas Transmission Pipeline Integrity Management". SoCalGas has started and has continued performing its baseline assessments.

The remaining pipeline segments requiring assessment are proving to be more challenging than the initial ones. One specific category posing significantly more challenges are the pipeline segments installed in casings. Pipelines in casings are commonly referred to as cased main. These are pipeline segments that are typically used to allow a pipeline to transverse railroads, highways, etc. The pipeline is placed inside another pipeline to provide additional support and protection. Once placed inside this annular space, the pipeline is protected, but it is also inaccessible. None of the external sections are visible and the typical installation will have a different geometry than the pipeline entering and exiting the casing. Cased mains are relatively short, averaging several hundred feet. Although shorter than some of the first pipelines segments assessed, some of these cased mains are proving more difficult due to the lack of, or limited, access and, at times, the geometry of the pipeline segment. The

[3] Code of Federal Regulations (CFR), 49 CFR 192, Subpart O, section 192.911.

current and proven techniques used for TIMP baseline assessments are not conducive for the assessments of cased main on pipelines that are not configured for internal inspection. There are other alternatives, but they can be very costly and time-intensive. Further, PHMSA has acknowledged the challenges that baseline assessments of cased main are posing for the whole industry. That PHMSA has continued its efforts to develop guidance for operators and conduct workshops is evidence of the challenge. For example, PHMSA recently held a workshop to gain industry input and it continues to express support for cased main assessments[4]. Even though there is acknowledgement of the difficulty and complexity to assess cased main, the deadline has not changed.

The third element of TIMP that is posing a challenge for SoCalGas is the added work of the reassessments. As required by the federal pipeline safety regulations under 49 C.F.R. § 192.901 Subpart O, SoCalGas has started to perform its reassessments. As previously noted, the reassessment phase is the on-going evaluation of the pipeline segments that were initially baseline assessed. The reassessments are added work, require the same level of analysis and evaluation, and create logistic challenges in scheduling.

Under TIMP, SoCalGas is facing two primary challenges. The first is the challenge to assess cased main. The second is the additional work from pipeline reassessments which is work added to the remaining baseline assessment work.

Pipeline Integrity— Distribution Integrity Management Program (DIMP)

The recently adopted pipeline safety regulations governing distribution pipeline integrity management, located at 49 C.F.R. § 192.1001 Subpart P "Gas Distribution Pipeline Integrity Management," are being developed and implemented. However, SoCalGas as a prudent operator undertook steps in anticipation of the DIMP regulations based on preliminary rule drafts, and its extensive experience with risk management and pipeline safety, to minimize the challenge. SoCalGas has started development and implementation of its integrity management plan to meet the fast-approaching deadline of August 2, 2011, by utilizing the DIMP Balancing Account (DIMPBA). The settlement approved in D.08-07-046 resulted in the establishment of the DIMPBA for costs associated with DIMP during the 2008 – 2011 GRC

[4] Pipeline and Hazardous Materials Safety Administration, Department of Transportation, Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs 3-4 (March 2010).

period. As forecasted in the TY 2008 GRC, SoCalGas has moved forward with the development and implementation of certain aspects as noted below.

Given that the work done to comply with Title 49 CFR Part 192 Subparts A through O are included in base margin, now that Subpart P (DIMP) is in effect, SoCalGas is proposing that the DIMP Balancing Account be closed on December 31, 2011. Details of the treatment of this account are provided in the Prepared Direct Testimony of Gregory Shimansky, in Exhibit SCG-34. Compliance with Subpart P leverages and builds upon the activities performed to be in compliance with the other applicable sections of Part 192. The DIMP forecast for 2012 is reflected in the SoCalGas base margin request.

Under DIMP, SoCalGas has been in development of the system-wide Geographic Information System (GIS) application. Data from several complex legacy systems is being analyzed, converted, and consolidated into the GIS and corporate database systems to enable effective and efficient management. SoCalGas is leveraging the knowledge it gained from the development and implementation of TIMP in this development process. Even though SoCalGas has developed a program for Transmission, it cannot simply make a carbon copy for its distribution integrity program. U.S. Transportation Secretary Ray LaHood commented upon the issuance of DIMP, stating that DIMP is more expansive than TIMP, covering a distribution system operator's <u>entire</u> system as opposed to focusing on facilities located in High Consequence Areas (HCAs). In addition, Mr. LaHood acknowledged the differences between distribution and transmission systems as significant; thus, the full implementation of DIMP will be challenging.

Once fully developed, DIMP will address the identification of threats, the evaluation and ranking of risks, the implementation of measures to minimize risks, and ways to measure performance. In addition, the plan will incorporate various measures that will appropriately address differences in system design and local conditions across SoCalGas' large service territory that impact system integrity. As the largest natural gas distributor in the U.S., the challenge is ensuring that the plan will address every aspect of the federal mandates. Because SoCalGas has a very large system, it must undertake far more technical and operational processes than the average pipeline system, thus increasing the complexities of the development and implementation. SoCalGas' projected costs for this key program are based on its close examination of the mandated requirements as well as its historical costs and experience for similar types of work across its service territory.

The Public Awareness (PA) Program is another regulatory-driven program that is creating another set of challenges. SoCalGas has implemented its PA program, as required by the federal pipeline safety regulations under 49 CFR 192.616 "Public Awareness", but the ongoing enhancements to the program to meet regulatory requirements for continuous improvement and effectiveness assessments are challenging. The biggest challenge is assessing and measuring the effectiveness of the PA program. With a diverse customer base and a myriad of communication media, assessing the awareness message can prove to be elusive. Raising awareness with each group of stakeholders poses a significant challenge due to language, media, and the message itself. Connecting with each group poses a significant challenge because the target groups have various media means by which they receive their information. A statement through the postal mail is not simply enough to make sure the PA safety message is being understood. As evidence of the challenges facing SoCalGas and the industry, PHMSA has conducted a workshop to gather comments and to provide guidance on how to address these concerns. These issues were clearly evident based on PHMSA's workshop agenda[5].

Environmental Mandates

Environmental costs continue to increase, driven by new federal and state mandates. GHGs are an emerging issue in California with the adoption of California State Assembly Bill 32 (AB 32). The new requirements mandated by AB 32 will add costs to SoCalGas' operation. At the federal level, the Environmental Protection Agency (EPA) is moving forward with GHG rules by proposing GHG reporting requirements under Subpart W[6]. These new rules will create both new and increased requirements for operators.

In September 2006, the Governor signed AB 32 as Division 25.5 of California Global Warming Solutions Act of 2006 (codified as Cal. Health and Safety Code Section 38500). In addition to California's regulation, the federal government is moving forward with compliance requirements to be issued by the EPA. EPA has proposed a supplemental rule to require reporting of GHGs under Subpart W[7]. SoCalGas anticipates new increased requirements by

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[5] *See* Pipeline Safety: Workshop on Public Awareness Programs, 75 Fed. Reg. 32,836 (June 9, 2010); Department of Transportation, Public Awareness Workshop, http://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=65&nocache=9963&nocache=263.

[6] Federal Register / Vol. 75, No. 69 / Monday, April 12, 2010 / Proposed Rules, 18608.

[7] EPA Proposed Rule, Mandatory Reporting of Greenhouse Gases; Petroleum and Natural Gas Systems – 75 Fed. Reg. 18455. April 12, 2010.

EPA, such as emission-level thresholds, source testing, and ongoing emissions monitoring. For now, and at a minimum, EPA has proposed increased reporting of GHGs.

Lastly, another cost driver which may prove challenging over the next few years is the costs associated with the increased storm water requirements that went into effect July 1, 2010. SoCalGas has reviewed the new Construction Stormwater Permit requirements and has provided an estimate of the costs. Although the costs at this time appear minor, SoCalGas believes these costs will increase over time, creating more challenges.

D. Summary of Request

For Commission adoption is SoCalGas' Gas Engineering TY 2012 request for its non-shared and shared O&M expenses of $78,399,000 and $16,053,000, respectively. These values are shown in Tables SCG-RKS-2 and SCG-RKS-3 for non-shared and shared expenses, respectively. Further, SoCalGas respectfully submits for Commission adoption its TY 2012 capital expenditures of $158,306,000, which are detailed in Table SCG-RKS-4.

The sections that follow contain the details of the forecasted expenditures for the O&M and capital requests submitted. Each section contains an explanation of the activities representing the costs, historical spending, and the foundation for the requested amount.

In summary, the requests for both O&M and capital are grounded on the need to continue to provide safe and reliable natural gas service. In addition, the requested amounts are predicated on the need to comply with the federal mandates for enhancing safety and reliability under the auspices of PHMSA's pipeline integrity programs for transmission and distribution systems. Further, the requested amount is essential to comply with the environmental mandates for air quality and storm water permitting. The requests not only represent the requirements for regulatory compliance, but they are also balanced with knowledge, operating experience, and reflect sound engineering principles. The TY 2012 forecast of expenses represents the minimum funding necessary to perform the required work to ensure public safety, maintain system reliability, and comply with the federal pipeline safety regulations that apply to the areas specified.

Table SCG-RKS-2
O&M Non-Shared Services
Testimony Section II
(Thousands of 2009 dollars)

ENGINEERING			
Categories of Management	**2009 Adjusted-Recorded**	**TY2012 Estimated**	**Change**
A. Gas Engineering	10,189	21,383	11,194
B. Pipeline Integrity - Transmission (Subpart O)	10,961	24,760	13,799
C. Pipeline Integrity - Distribution (Subpart P)	6,570	31,097	24,527
D. Public Awareness	307	1,159	852
Total	**28,027**	**78,399**	**50,372**

Table SCG-RKS-3
O&M Shared Services (Book Expense)
Testimony Section III
(Thousands of 2009 dollars)

ENGINEERING			
Categories of Management	**2009 Adjusted-Recorded**	**TY2012 Estimated**	**Change**
A. General Engineering	8,282	9,206	924
B. Pipeline Integrity	3,216	5,700	2,484
C. Pipeline Integrity - Distribution IMP	190	343	153
D. Pipeline Design & Gas Standards	603	670	67
E. USS Billed to CCTR	86	134	48
Total Shared Services (Book Expense)	**12,377**	**16,053**	**3,676**

Table SCG-RKS-4
Summary of Capital Expenditures
Testimony Section IV (Thousands 2009 dollars)

Category Description	**2009 Recorded**	**2010 Estimated**	**2011 Estimated**	**2012 Estimated**
1. 276 – Pipeline Integrity – Dist.	1,629	14,405	22,902	20,762
2. 277 – DIMP	0	0	14,262	30,224
3. 3X1 – Transmission Pipelines – New Additions	25,768	9,519	11,197	19,292
4. 3X2 — Replacements and Pipeline Integrity Program (PIP)	39,489	42,766	35,227	25,917
5. 3X3 – Transmission Pipeline –	1,137	1,019	2,010	2,010

Relocations - Freeway				
6. 3X4 – Transmission Pipeline Relocations – Franchise/Private	5,567	10,104	8,128	11,105
7. BC 3X5 - – Gas Transmission – Compressor Stations	2,514	2,303	5,407	19,257
8. BC 3X6 – Gas Transmission Pipelines – Cathodic Protection	836	2,413	1,793	1,793
9. BC 3X8 - – Gas Transmission – Meter and Regulator	5,609	8,777	4,526	4,526
10. BC 3X9 – Gas Transmission – Auxiliary Equipment	865	882	1,651	1,651
11. BC 617 - – Gas Transmission – Pipeline Land Rights	120	0	4,000	8,300
12. BC 730 – Gas Transmission – Laboratory Equipment	250	265	935	295
13. BC 736 – Gas Transmission & Storage – Capital Tools	862	307	307	307
14. BC 1001 – Gas Storage – S&E Direct Overheads	265	240	278	335
15. BC 1002 Gas Transmission – S&E Direct Overheads	894	904	1,046	1,260
16. BC 01100 – Gas Transmission – Coastal Region Conservation Program	134	886	664	0
17. BC 00399 – Sustainable SoCal Program	0	0	0	11,272
Total Capital:	**85,939**	**94,790**	**114,333**	**158,306**

II. NONSHARED SERVICES

A. Introduction

The activities described in this section are the engineering and technical functions that are performed in support of distribution, transmission, and storage operations on the operating precepts to provide safe, reliable, and efficient natural gas service to SoCalGas customers. Table SCG-RKS-5 shows the categories of management that comprise the non-shared O&M costs. These non-shared O&M expenses are required, as a prudent operator, to provide the necessary engineering support and management to effectively manage the pipeline programs for integrity and public awareness.

For purposes of this discussion, these activities are summarized into four workgroups, also referred to as categories of management or simply categories:

- Gas Engineering;
- Pipeline Integrity Management – Transmission (TIMP);
- Pipeline Integrity Management – Distribution (DIMP);
- Public Awareness (PA).

Table SCG-RKS-5
O&M Non-Shared Services--Summary
(Thousands of 2009 dollars)

ENGINEERING			
Categories of Management	**2009 Adjusted-Recorded**	**TY2012 Estimated**	**Change**
A. Gas Engineering	10,189	21,383	11,194
B. Pipeline Integrity - Transmission (Subpart O)	10,961	24,760	13,799
C. Pipeline Integrity - Distribution (Subpart P)	6,570	31,097	24,527
D. Public Awareness	307	1,159	852
Total	**28,027**	**78,399**	**50,372**

Within each category is a description of associated activities. In addition, a narrative is provided on the change in the costs and rationale driving the changes. Additional program and cost details are in the workpapers associated with my testimony.

SoCalGas operates an expansive gas delivery system that encompassing 20,000 square miles. It requires considerable resources to provide safe, reliable natural gas service to over

20.5 million consumers spanning over 500 communities[8]. From a broad perspective, there are two major categories of effort to be discussed—Pipeline Integrity Programs and General Engineering. General Engineering is the broad discipline needed to support SoCalGas' large gas operations. Within Pipeline Integrity there are two separate and distinct programs. These two programs address the two distinct gas infrastructures SoCalGas operates: Transmission and Distribution pipeline systems and their associated facilities.

B. Operations and Maintenance (O&M) Activities.

Table SCG-RKS-6
O&M Non-Shared Services—General Engineering Summary
(Thousands of 2009 dollars)

ENGINEERING			
A. Gas Engineering	**2009 Adjusted-Recorded**	**TY2012 Estimated**	**Change**
1. Gas Engineering	10,189	21,383	11,194
Total	**10,189**	**21,383**	**11,194**

Under the broad category of General Engineering, many engineering activities are performed to ensure a safe and reliable operation. Specifically, the support is provided to Transmission, Storage, Distribution, and Customer Services. In this testimony, these general engineering activities have been divided into seven sub-workgroups as follows:

- Gas Measurement, Control and Pressure Regulation;
- Engineering Analysis Center;
- Engineering Design and Support;
- Asset and Data Management;
- Planning and Analysis;
- Gas Infrastructure Project Management and Construction; and
- Sustainable SoCal Programs.

The breakdown into seven categories (workgroups) is designed to provide a clearer overview of the work and development of the forecast. The development of the O&M non-shared services forecast relied on the experience of the engineering department managers and

[8] www.socalgas.com , Company profile web page.

historical spending for the years 2005 through 2009. Because the work and workgroups are more of a mature nature, a five-year average has been employed to develop the forecast, unless otherwise noted. For the newer programs such as the Pipeline Integrity Management Programs, the forecast approach was predominately zero-based because the programs have not matured or come to full cycle. Thus, a forecast using historical data is not appropriate and a forecast methodology based on the units of work was utilized. Again, for the General Engineering forecast, the respective workgroup managers were consulted to develop a sound and realistic forecast of expenses. The managers' forecasts accounted for the variations associated with timing, permit-acquisition-and-issuance delays, and other realities, and the forecasts include their best assessment of needed resources associated with workload increases.

The total non-shared services O&M forecast for the General Engineering category is $10,891,000. However, of the total, only 12% of the increase is associated with the core duties and responsibilities of Gas Engineering. The remaining increase in projected expenses is associated with newly imposed mandates, which are explained later in my testimony.

<u>Gas Measurement, Control, and Pressure Regulation (MRC)</u>

Activities in this cost center include: the maintenance and operation of 22 SoCalGas Natural Gas Vehicle (NGV) fueling stations used for public and operational fleet fueling, limited support for customers' NGV fueling stations, electrical maintenance/basic electrician services to support SoCalGas' multitude of operational and office facilities, and the maintenance of gasoline station Underground Storage Tank (UST) control and monitoring systems.

The TY 2012 forecast methodology for this category is a five-year average. This methodology best reflects the future activity and accounts for the year-to-year variation in the work.

<u>Engineering Analysis Center (EAC)</u>

The work performed under this activity includes a variety of Engineering and technical services support on such matters as air quality compliance. This group provides support for over 200,000 horsepower of compression used for transmission and storage activities. The compressor engines are geographically dispersed throughout the SoCalGas service territory and, as such, fall under various air quality management regulations and land-use permitting requirements, such as those of the South Coast Air Quality Management District (SCAQMD), the Bureau of Land Management (BLM), the Coastal Commission, Fish and Game, and Department of Forestry, to name a few. Specialized testing for compliance with air quality regulations is supported by this workgroup. Compressor equipment standards, the assessment of new compressor technology, and compressor design fall within the responsibility of this group. In addition, the work performed in this category includes the support services necessary to develop and maintain gas facility standards, corrosion control, metallurgy, water treatment, materials specifications and material quality control, and quality assurance.

Increases are driven by the work needed to meet the new air quality requirements as defined by AB 32[9] bringing GHGs under the jurisdiction and regulation of the California Air Resources Board (CARB). The support provided by this group ensures that Transmission, Distribution, and Storage operations are in compliance with the GHG rule for monitoring and reporting. Additionally, this workgroup provides the technical support for AB 32 operating compliance. The GHG rule is being driven by two regulatory bodies (CARB and EPA), which can essentially double the work. Under AB 32, SoCalGas is limiting its funding to initially meet the requirements under the mandates of monitoring, reporting and recordkeeping (MRR). To do so will require methodologies that meet the requirements of the regulations which fall under this activity. A five-year average was used to forecast the TY 2012 expenses. Additional expenses of $180,000 are being forecasted to support the impacts of increased environmental regulations associated with the various monitoring, sampling and analyzing, reporting, and recordkeeping activities. Details for the requested funding are summarized in the associated workpapers to this testimony.

<u>Engineering Design</u>

This activity encompasses pipeline and gas facilities engineering design. The work performed includes: evaluation, specification, and/or modification of major compressor station and storage facility plant equipment such as heat exchangers, cooling towers, pressure vessels, compressors, generators, and gas treatment apparatus; drafting; engineering drawing management; strategic planning; and field support. Facilities engineering encompasses civil, electrical, control systems, and structural designs for pipelines, compressor stations, storage fields, and seismic retrofit activities. The work performed also includes development of gas

[9] Cal. Health and Safety Code Section 38500.

processing standards and design; drafting and design services; and distribution planning policy development. In addition to the other activities, the PA program management noted above occurs within Engineering Design.

This activity provides an enhanced coordination of development and implementation of company policies and procedures company-wide for consistency among the various operating offices. The single point of contact helps ensure consistency. Activities within this area include the review of existing and development of new procedures, coordination and development of distribution system analysis training, review of critical distribution planning projects, and providing technical guidance to the planning engineers within distribution. A five-year average was used to forecast the TY 2012 expenses. This methodology best reflects the future activity and accounts for the year-to-year variation in the work.

Asset and Data Management

Asset and data management requires computer-based work management systems, mapping products, geographic information system development, and technical computing management and support. Part of the activity performed in this category is the work to maintain and upgrade software applications. These systems and supporting activities are necessary for the safe and efficient operation and maintenance of the gas infrastructure from receipt point through transmission, storage, distribution, and customer services.

Within this category is work performed to support computer programs and systems not provided by the Company's Information Technology group. Operations Technology provides computer-aided drafting and design (CADD) support within Engineering, and development of GIS which will be used to satisfy federally mandated Pipeline Integrity rule requirements, support of the High Pressure Pipeline Database and related Geofields applications, and the Network Analysis System Automation (NASA) database and related application. It also includes the resources required to manage and maintain four mapping systems and the work management systems vital to operations.

Because this category of work maintains and supports engineering-specific computer software, the activity in this workgroup includes costs associated with upgrade/enhancements required for the CADD applications that support Transmission Engineering Design. Currently, CADD applications are using Microstation J which is running on the Windows XP operating system. This version will no longer be supported by Microsoft after 2013, and Microstation J is not supported on the Windows 7 operating system. Combined, these two limitations will require an upgrade of the CADD software and the associated operating system. The upgrade to the operating system will provide a compatible and operational system for both current and future needs. Upgrading the CADD software to Microstation (V8) will provide SoCalGas with the ability to meet industry standards, interface successfully with other systems, and provide the tools necessary to facilitate design work with outside vendors. This upgrade will be implemented in phases, and the TY 2012 phase is estimated to cost $187,000.

A fundamental shift has occurred to the work and processes supported by this workgroup, caused by the introduction of new technology. The new technology requires subject matter experts skilled in these areas. SoCalGas is forecasting an increase to its 2009 adjusted recorded expense level. The following duties are skills that this workgroup performs currently:

- Providing technical support for the systems that support the field organization, including Construction Management System (CMS), the New Business Management Systems (NBMS), KorTerra application (the ticketing system for Locate and Mark), the mobile data terminals, and all of the interfaces between these systems;
- Identifying best practices and opportunities for improving, developing, and implementing new technologies for the field and office organizations. Operations Technology: investigates opportunities; gathers relevant information; analyzes the data; develops the business case; implements the change; and communicates the business changes to the various Distribution departments; and
- Providing project management of large cross-functional projects and activities associated with Distribution field technologies.

The shift in work is attributable to new technology and requires new skills and responsibilities of the workgroup. SoCalGas is forecasting $1,108,000 to add new positions to the Operations Technology group in order to support an increasingly complex suite of systems and the increase of mobile data terminals throughout the region territories. These positions consist of the following:

- Three positions to support Supervisor Enablement & Mobile - $300,000;
- Two positions to support SAP production support - $160,000;

- Two positions to support Click Forecasting, Scheduling, and Dispatch (FSD) - $180,000;
- One Lead position to oversee the support team for Click FSD and SAP production - $100,000;
- The full-year effect of a Business Analyst position filled in 2009 - $28,000; and
- Four positions to support GIS - $340,000.

The Operation Technology staff is a group of functional subject matter experts with specialized knowledge of gas distribution functions and activities. Almost all gas distribution projects require support from Operations Technology's project management, analytical, and technical staff. Operations Technology staff is the major point of contact with the Information Technology (IT) infrastructure, system application development, maintenance, and enhancement departments. The subject matter experts are the front-line support for gas distribution applications such as CMS, a critical work management application, which supports work initiation, work planning & design, both at project and work request level, permits, scheduling & dispatching, final reconciliation, and paving for capital and maintenance work. Within CMS, the Service History application maintains a historical record and information for each service reported through final reconciliation or direct updates within the Service History system. This system is used by approximately 1,400 gas operations field planners, supervisors, dispatchers, and clerical resources across the entire SoCalGas territory.

The Operations Technology staff also supports NBMS, a new business project management tool used for pricing, administration, and billing of all new business construction work. The major NBMS support functions are the initiation of new projects, contract generation (10,000 contracts on average generated per year), customer advances, posting payments, establishing new service address facilities, project reconciliation, refunds, collection activity, and reporting. This workgroup supports over 250 NBMS system users.

Field Hardware Support evaluates, procures, configures, and supports mobile hardware, including ruggedized tablets and mobile data terminals (MDTs) for SoCalGas gas operations field users. The hardware team supports 300 Locate and Mark, 265 Supervisor Enablement, and 550 Construction Crew MDTs and the associated software. Software consists of specialized and propriety systems such as KorTerra (dig alert ticketing system), Blackout Pro (used in the field computers), Web View (atlas sheet viewer), and all other MDT applications.

GIS support provides general application support and acts as the liaison between the SoCalGas gas operations field and office users and IT. Major support functions include: user account maintenance; application installations; printer setup; digitizing/mapping issues; reporting issues; evaluating, prioritizing, and implementing system enhancements; and training. GIS support includes, but is not limited to: general mapping, online viewing, grid maintenance, plotting, asset queries and reporting, and equipment number assignments. GIS will also support two separate interfaces: 1) ArcFM viewer for over 1400 mobile users, and 2) 3000 Web users (ArcFM servers).

Operations Technology's responsibilities also include: implementing regulatory, legislative, and business initiatives that impact gas operations; evaluating business and system impacts; coordinating the implementation of proposed system changes with IT; prioritizing system change initiatives to efficiently allocate resources; and training the personnel who use the technical tools on a daily basis.

The overall scope of responsibilities and level of activity for Operations Technology staff has increased in recent years, especially from the deployment of new technology. Additional compliance and control activities are due to: Sarbanes-Oxley assessment and test activities; project planning related to customer invoicing; post-completion activities; regulatory and compliance requirements; a growing field work force utilizing MDTs (an increase of approximately 800 new MDT users); and other hardware-related peripherals resulting from new Supervisor Enablement and Field Force projects that increase the complexities presented by a mobile, technically advanced workforce.

The workgroup's activities have shifted to support the new technology and transfer of 13 positions to pipeline integrity to support the GIS efforts associated with that program. The skill sets used to support the data conversion and other GIS-related pipeline integrity activities required the transfer of those activities and positions to Cost Center 2200-2325.

The net effect of the organizational shift in former duties, and the addition of new and more skilled labor, is an increase of approximately $700,000 in TY 2012 over 2009 adjusted recorded levels.

A five-year average was used to forecast the TY 2012 expenses. This methodology best reflects the activity and accounts for the year-to-year variation in the work. Added to the forecast were the CADD upgrade and the net effect of the organizational changes.

Planning and Analysis

Resources to analyze and forecast near-term and long-term system requirements for SoCalGas operations are represented in this category. Using modeling techniques and knowledge of both interstate and intrastate gas demand, system capacity, and gas production, assessments are made that drive planning for increases in capacity, capital investment, and scheduling maintenance activities. This category also includes the resources required to optimize the use of transmission and storage capacity in conjunction with market analysis, open seasons, customer surveys, and to support the execution of supplier and customer contracts. Included is the evaluation of access capability (interconnects) with new and expanding interstate pipelines, LNG supplies, as well as development of the policies and plans for transmission and storage expansions. A five-year average was used to forecast costs for this group. This methodology best reflects the future activity and accounts for the year-to-year variation in the work.

As noted previously, with the passage of AB 32[10], SoCalGas will be significantly impacted by this new state-driven mandate to address GHGs. The legislation has three distinct compliance components that SoCalGas will need to meet. Each component is further detailed in my testimony. As is discussed in the Prepared Direct Testimony of Witness Ms. Lisa P. Gomez in Exhibit SCG-15, AB 32 will significantly impact the ongoing cost of operations. AB 32 imposes many environmental requirements that translate into significant expenditures by SoCalGas. The three incremental cost factors emanating from this legislation are as follows: 1) program administrative fees; 2) cap-and-trade costs, and 3) compliance and reporting requirements. The specifics of the accounting treatment for these new costs are discussed in the Prepared Direct Testimony of Witness Mr. Gregory Shimansky in Exhibit SCG-34, as part of the New Environmental Regulatory Balancing Account (NERBA).

SoCalGas has forecasted that the impact of this new regulation will require significant funds. For example, the cost for the program administrative fee is forecasted to be $4,542,000 for TY 2012, while the cap-and-trade element to offset GHG emissions is estimated at $5,000,000.

The first category of AB 32 GHG expense is the program administration fee. The fee value was derived from initial work prepared by CARB for the new GHG rule[11]. This fee is

[10] Cal. Health and Safety Code Section 38500.
[11] AB 32 (Cal. Health & Safety Code § 38597), *New article 3, sections 95200 to 95207, title 17, California Code of Regulations.*

required for all public utility gas corporations and publicly owned natural gas utilities operating in California. Utilities must annually report the aggregate quantity of therms of natural gas delivered at the meter to end-use customers, excluding natural gas delivered to wholesale customers and to electricity generating units (EGUs). The regulation's approach is for Local Distribution Companies (LDCs) (public and non-public) to pay a fee for each therm of gas delivered to any end-use customer excluding wholesale customers and EGUs. EGUs, cement (non-fuel emissions) and refineries will pay CARB directly based on their Mandatory Reporting Rule data. SoCalGas has estimated its TY 2012 fee to be $4,542,000 based on SoCalGas' 2008 throughput minus EGU and wholesale throughput. Future increases would be driven by the overall state program costs as well as SoCalGas' future throughput.

The second category of AB 32 GHG program expense is the emission credits needed to offset GHG emissions from five SoCalGas facilities. This expense is the fee for the cap-and-trade activity for only the largest emitters. The estimate for this fee is based on the facilities that emit over 25 metric tons per year. For SoCalGas, this expense has been estimated at $5,000,000 based on the emissions of five facilities identified to be in the program. SoCalGas used the methodology as defined by CARB and AB 32 to develop its cap-and-trade forecast for the emission credits. The first step to the calculation was using historical emission data. Using 2008 CO_2 emission values from the qualifying major facilities at SoCalGas, listed in Table SCG-RKS-7, the total was approximately 250,000 metric tons (MT). A price value for emission credits is based on an estimated cost of $20/MT and would result in total allowance costs of approximately $5,000,000 per year. The value is a conservative number based on an average emission credit price.

Table SCG-RKS-7

CO2 Emissions for Facilities under AB 32 GHG Regulations

SoCalGas Facility	CO_2 Emission
Aliso Canyon (Storage)	102,096 MT
Honor Rancho (Storage)	30,956 MT
Blythe (Transmission)	27,866 MT
South Needles (Trans.)	48,855 MT
Newberry Springs (Trans.)	40,103 MT
Total	249,876 MT

*MT denotes unit of measure as Metric Ton

The fee amounts will vary as allowance prices and quantities purchased vary from year to year to meet annual compliance requirements. The cap-and-trade fee is based on many variables such as SoCalGas' production and operating rates at these facilities which are a function of gas demand, which vary from year to year. Consequently, emissions in individual years could be higher or lower than what were emitted in 2008. Future costs will be driven by the overall state program costs and as SoCalGas emissions fluctuate.

The third category of AB 32 GHG expense is the program management and reporting expenses, which is a shared expense and further described in my testimony in cost center 2200-0323 under the shared-services discussion. However, it should be noted that nearly 90% of the cost increase under General Engineering is not associated with its core duties, but rather from regulatory requirements.

Gas Infrastructure Project Management and Construction

The functional and technical expertise and resources needed to perform technical development consultation, planning, permitting, detailed design, material specifications and management, infrastructure facility construction, and the commissioning and general project management of major gas facility infrastructure projects, are represented in this category. The functional responsibility to oversee, maintain, and provide continuous development of construction standards and best practices for Gas Transmission infrastructure facilities, construction, and contractor services are also provided by this group. These resources provide analysis and consultation, cost estimates, permit requirements, and scheduling of major gas infrastructure facilities necessary to serve major customers for the continued safe and reliable transmission of natural gas throughout the service territory. The projects managed in this area vary by size and complexity. Project sizes can range from relatively small enhancements with difficult permit requirements, construction or public relations conditions, to auxiliary systems, controls, or major compression-drive units at pipeline compressor stations, to the design and construction of an entire major gas transmission facility including many miles of large diameter pipeline and associated compression. These major project management resources are also utilized to provide project management and construction needs to repair or replace heavily damaged or compromised major gas infrastructure facilities under emergency conditions such as natural disasters like the major landslides caused by historic rain events recently. The primary role of the resources identified here is the major project management and construction expertise used to evaluate, estimate, implement, construct, and commission many of the major capital projects represented in the capital budget and required for the continued safe, reliable delivery of natural gas to our customers. These resources also provide the technical knowledge and expertise to consult with outside stakeholders who desire to analyze various interconnects and infrastructure enhancements, and the timing and costs associated with their development projects. These various stakeholder projects can include utility gas supply to major utility electric generation plants, LNG suppliers, land developers, and the many various Public Works Agencies involved in public works projects. No additional resources are being forecasted for this sub-workgroup.

<u>Sustainable SoCal Program</u>

The last sub-workgroup under General Engineering is the Sustainable SoCal Program activity. As discussed in the Prepared Direct Testimony of Witness Ms. Gillian Wright, SoCalGas is moving forward with its Sustainable SoCal Program. In my testimony, I will address the engineering and technology costs associated with the implementation.

In the start-up phase of this program, SoCalGas proposes to install four biogas conditioning systems at certain customer sites for the purpose of capturing raw biogas, processing it to meet pipeline quality gas specifications (biomethane), and injecting the gas into the SoCalGas pipeline system. This project will advance the market development efforts associated with producing pipeline-quality biogas from digester raw biogas generated from wastewater treatment plants. There are two components to the implementation: a capital (installation) component, and an O&M (ongoing inspection and maintenance) component.

The capital component of the project is detailed in my testimony in Budget Code (BC) 0399. The average O&M expense component for all four units, when fully operational, is $1,212,000.

SoCalGas has evaluated the current market and available technology. There are three viable technologies to treat or scrub the waste gas stream into a pipeline-quality gas. Those three technologies are as follows:

- Amine gas treating;
- Temperature Swing Adsorption; and
- Pressure Swing Adsorption.

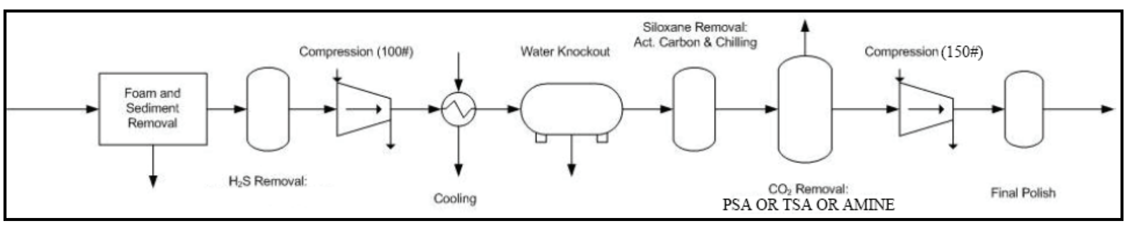
Each technology has its advantages and disadvantages. SoCalGas has determined that the most viable technology to implement initially is the Pressure Swing Adsorption (PSA) because of its relatively low cost and reduced complexity. Although SoCalGas is initially focusing on implementing PSA, as the technology matures and as other technologies are introduced, SoCalGas will continually review, evaluate, and implement more advantageous technology if appropriate.

Adsorption refers to the accumulation of molecules of a gas or liquid on the surface of another substance without actually penetrating the other substance. PSA is a technology used to separate some gas species from a mixture of gases under pressure according to the species' molecular characteristics and affinity for an adsorbent material. Pressure swing adsorption processes rely on the fact that, under pressure, gases tend to be attracted to solid surfaces, or "adsorbed". The higher the pressure, the more gas is adsorbed; when the pressure is reduced, the gas is released, or desorbed. PSA processes can be used to separate gases in a mixture because different gases tend to be attracted to different solid surfaces more or less strongly.

The primary advantages of PSA are that the design is the least complicated and most user-friendly of the available technologies.

An illustration of the scrubbing technology is depicted in Figure SCG-RKS-2.

Figure SCG-RKS-2



Pressure Swing Adsorption (PSA) Process Diagram Illustration

To implement Sustainable SoCal Programs using PSA technology will require capital funding. The capital outlays to install PSA are discussed in further detail in my testimony under the Capital Budget Code 0399. Once the PSA system is installed, SoCalGas will incur O&M costs for running the unit. These costs are primarily associated with the need to replace worn-out parts and to run the system. Based on the PSA technology and the size of the site, SoCalGas will require $606,000 in TY 2012. Since there is no history for this newly initiated activity, the increase is zero-based using the target-market parameters SoCalGas has identified.

An Overview of Pipeline Integrity Management

A large element that drives SoCalGas' request in Gas Engineering is its functional responsibility for pipeline integrity management. SoCalGas has an active pipeline integrity management program in place to assure safe and reliable operation of approximately 3,989 miles of DOT-defined transmission steel pipeline and over 96,000 miles of distribution steel and plastic mains and services. The pipelines vary in age, condition, construction, manufacturer, coating, topography, environment, and the manner in which they are operated (e.g. % Specified Minimum Yield Strength (SMYS), pressure cycling, etc.). Each of these attributes must be evaluated to determine performance, integrity, and then risk ranked. Based on sound engineering principles, evaluations are conducted to determine the best course of action to take to meet the mandates of DOT's Pipeline Integrity rules found in the Code of Federal Regulations (CFR) 49 C.F.R. § 192.901 Subpart O "Gas Transmission Pipeline Integrity Management" and 49 C.F.R. § 192.1001 Subpart P, "Gas Distribution Pipeline Integrity Management." To effectively address the non-shared components of the pipeline integrity requirements for both Transmission and Distribution, SoCalGas has forecasted a total TY 2012 expense of $57,210,000 which is the combined values in Table SCG-RKS-5, rows B and C.

Pipeline Integrity Management—Transmission

Table SCG-RKS-8
O&M Non-Shared Services—Pipeline Integrity Transmission
(Thousands of 2009 dollars)

ENGINEERING			
B. Pipeline Integrity - Transmission (Subpart O)	**2009 Adjusted-Recorded**	**TY2012 Estimated**	**Change**
1. Transmission Pipeline Integrity	10,961	24,760	13,799
Total	**10,961**	**24,760**	**13,799**

On December 17, 2002, the Pipeline Safety Improvement Act (PSIA) of 2002 was signed into law and subsequently 49 C.F.R. § 192.901 Subpart O regulations were implemented. The final rule implementing these regulations was effective February 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines in High Consequence Areas (HCAs), analyze the risk posed by these threats, collect information about the physical condition of their pipelines, and take actions to minimize applicable threats and integrity concerns before pipeline failures occur. As a result, approximately 1,149 of the 3,989 miles of transmission pipeline at SoCalGas must be assessed during a ten-year period ending in 2012. Once the initial assessment (baseline) is completed for a given pipe segment, it must be reassessed no later than every seven years thereafter. The reassessment frequency is primarily dependent on the results of the previous assessment as well as knowledge gained from integrated data generated through the integrity processes performed throughout the system. For SoCalGas, the reassessment phase began in 2009. As noted earlier, the Integrity Management (IM) program for Transmission is the Transmission Integrity Management Program (TIMP). TIMP is a very prescriptive program with compulsory analytical methods, dates, and re-evaluation methodologies. TIMP focuses on a subset of the Transmission system, HCAs, that are high population-density areas. The reason for this focus is because, in the event of a pipeline failure, the consequences could be significant. TIMP is the first of PHMSA's two natural gas IM programs. The purpose for these programs is to improve the safety and reliability of pipeline systems. Under TIMP, SoCalGas takes into account information concerning the pipeline infrastructure, its operating environment, and its performance history, integrating the data into a broad evaluation to determine an overall susceptibility of the pipeline infrastructure to failure. The output from that evaluation is a detailed analysis and a pipeline segment-specific plan to address those susceptibilities.[12]

The HCA pipeline segments are assessed in accordance with the Utilities' Baseline Assessment Plan (BAP) and scheduled reassessments. Simply stated, the BAP contains the goals and schedule for how and when the TIMP assessments will be performed. The pipelines within SoCalGas' service territory vary in age, condition, construction, manufacture, coating, geography, environment, and the manner in which they are operated (e.g. % Specified Minimum Yield Strength (SMYS) and pressure cycling). As part of pipeline integrity management, information concerning the pipeline infrastructure, operating environment and

[12] Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines); Final Rule, page 69778 Federal Register / Vol. 68, No. 240 / Monday, December 15, 2003 / Rules and Regulations.

performance history is integrated into a broad evaluation of the overall susceptibility of the pipeline infrastructure to failure. All of this information is analyzed in detail for each pipeline segment and specific integrity-related plans developed for each. Several different methods are used to assess and evaluate the pipelines in the system. There are three primary methods of assessments: External Corrosion Direct Assessment (ECDA), In-line Inspection (ILI), and pressure testing.

ECDA is a process that proactively seeks to identify external corrosion defects before they grow to a size that affects the structural integrity of the inspected pipeline segment. The process requires integration of operating data, including interviews with operations personnel, and the completion of above-ground surveys. This information is used to identify and define the severity of coating faults, diminished cathodic protection, and areas where corrosion may have occurred or may be occurring. Once these areas are identified, excavation of prioritized sites for pipe surface evaluations to validate or re-rank the identified areas is completed. Any necessary repairs or reconditioning of pipeline coating are completed during the excavation. After the excavation is complete, the data is used to determine the interval until the next reassessment of the pipeline up to a maximum of seven years. ECDA is labor-intensive and, depending on the location of the excavations, the costs can be significant.

The ILI method is an in-line inspection method using specialized inspection tools that travel inside the pipeline. These tools are sometimes referred to as "smart pigs". The pigs come in a variety of types with different measurement capabilities which assist in collecting information about the pipeline. However, this specialized tool requires that the pipeline be configured to accommodate its passage. As this technology did not exist when many of these pipelines were constructed, the use of this assessment method often requires pipelines to be modified or retrofitted to allow passage of the tool. Retrofits include the replacement of valves, removal of certain bends and any other obstructions for passage, as well as the addition of facilities to insert and remove the tool. Once the pipeline is retrofitted to allow passage of the pig, a series of them is passed through the pipeline to clean and measure pipeline features such as pipeline wall thickness. Once the tools have been used and the data collected, the ILI assessment process begins and is very similar to ECDA. The inspection data is used to identify and define areas of concern regarding the structural integrity of the pipeline. These areas could include locations where corrosion has occurred or may be occurring as evidenced by lower-than-acceptable wall thickness measurements. Once these areas are identified, excavation of prioritized sites for pipe surface evaluations to validate or re-rank the identified areas is completed. Repair or reconditioning of pipeline coating is completed during the excavation. After the excavation is complete, the data is analyzed to determine the next reassessment interval for the pipeline up to a maximum of seven years.

The baseline assessments that remain are proving to be challenging in complexity. The methods previously prescribed are not as conducive for some of these remaining segments. This challenge is taking more time and resources to complete. One such example is cased mains. The difficulty and complexity of these segments are from their location, limited access and, in some cases, the geometry of the facilities. Since the pipe is encased within the annular space of another pipe, ECDA techniques are not effective or applicable. Because the remaining cased mains are underneath railroads or on bridges in congested areas, the ability to use ILI technology is virtually impossible.

To illustrate the difficulty, one cased-main example is presented. This cased-main example occurred near downtown Los Angeles. The situation involved a pipeline segment that spans the 110 Freeway near the densely populated downtown center of Los Angeles on a heavily traveled freeway. This cased main needed a baseline assessment. The cased main was determined to be unpiggable because of its geometry. Adding to the difficulty was that it spanned a pedestrian bridge over the freeway. Although TIMP provides some options to address some situations, the alternative provided under TIMP to lower the pressure of the pipeline was unacceptable. Lowering the pressure would have had a detrimental impact to the operations and adversely affected the Company’s ability to deliver gas in the area. The remaining options were either to replace the line by rerouting it, or by boring underneath the freeway. These two options were estimated to cost between $3-$6 million. The best solution identified was to span the bridge again with the agreement of the bridge owner, the California Department of Transportation (CalTrans). The solution was agreed upon only after several technical exchanges and an evaluation of the bridge’s seismic capacity to carry a new pipeline. This new pipeline would replace the unpiggable segment. However, as a condition of replacement, SoCalGas will need to account for potential seismic activity when replacing the segment. Time, effort, and sound engineering principles were required to reach a successful conclusion, but only after months of technical exchange. While this is only one pipeline segment, it is an example of the type of challenges facing SoCalGas and the rest of the industry.

SoCalGas is actively pursuing a hybrid technology of ILI to assess cased main. As noted earlier in this testimony, one of the challenges it is facing is to effectively baseline assess cased main. The approach will be the use of a tethered pig. This method of assessment has the advantage of ILI but can be adapted to cased main with some additional modifications to the entrance and exit of the cased main. Unlike conventional ILI, where the assessment tool—the pig—is inserted and pushed by a differential of gas pressure on either side of the pig, a tethered pig must be tied (tethered) and mechanically pulled through the cased main. The cost and effort to set up is more than a typical ILI assessment as the pipeline may need to be taken out of service and access points can be close together due to limitations on the number and types of bends the tether can accommodate, as well as the length of the tether. The cost of a tethered pig assessment as compared to a typical ILI assessment can be as much as three to five times per inspection and is even greater on a per–foot-of-pipeline-inspected basis. The third assessment method is the pressure test. The pressure test is typically performed immediately after construction and prior to placing the pipeline in service. This method uses a hydraulic approach by filling the pipeline, usually with water, at a pressure greater than the maximum allowable operating pressure (MAOP) for a fixed period of time. In certain circumstances, the pipeline may be temporarily removed from service, pressure-tested post-construction, and then returned to service.

In addition to the above methods of inspection, pipeline integrity management activities also include internal and external corrosion control, metallurgical assessment, damage prevention, integrity assessment, inspection and excavation for verification, pipeline-related quality control, evaluating susceptibility to external factors such as seismic activity, and the development and implementation of remediation plans. Pipeline integrity management support activities include procurement, quality control, deployment, and operations and maintenance of the pipeline assets.

To date, SoCalGas has completed approximately 80% of its baseline assessments and must be finished with the remaining HCA assessments by December 17, 2012.

Under TIMP, an operator has ten years to conduct its baseline assessments in HCAs. All HCAs in existence as of December 2002 must have a baseline inspection completed by December 2012. After the completion of a baseline assessment for each and every HCA segment, an operator is required to reassess that same segment within seven years of the completion of the last assessment.

SoCalGas and SDG&E manage the TIMP program as "related operators". As such, the combined transmission pipeline systems for each company are addressed by a single Baseline Assessment Plan. Having one program for both Utilities simplifies and reduces the cost associated with compliance and program management. This related-operator approach also ensures that resources are allocated in the most effective manner possible.

Due to the lower risk associated with smaller-diameter pipelines, the TIMP baseline assessment schedule calls for an elevated number of these smaller-diameter and shorter-segment pipelines to be baseline assessed in the second five-year period of the program (2008 – 2012). The total cost to assess these comparatively shorter-length, smaller-diameter pipeline segments in the second five-year period is greater than the cost to assess the larger-diameter, longer-length segments completed during the first five-year period of the program. SoCalGas must baseline assess approximately 1149 miles out of its 3989 miles of transmission pipeline. In addition, each cased pipeline segment must also be assessed.

SoCalGas is in the final steps of completing its baseline assessments as mandated under TIMP. At the same time, SoCalGas has initiated the reassessment phase of TIMP. This reassessment phase started in 2009. The combination of these two activities is creating challenges. One challenge involves scheduling because of the increased work in conducting reassessments. The two activities combined are requiring additional resources to complete the tasks. To illustrate the amount of work SoCalGas is facing through TY 2012, Table SCG-RKS-9 is presented. In this table, the three distinct TIMP assessments are listed—Baseline, Casings (cased mains, baseline) and Reassessments. The table lists the baseline and reassessment activities in miles. However, cased main (casings) are listed in terms of volume (the count). As stated before, casings are much shorter Transmission pipeline segments to be assessed, typically measuring a few hundred feet. Yet, as illustrated in the example of the pedestrian bridge crossing, the effort can be significant. Hence, the method that SoCalGas has used to forecast its TY 2012 funding is a zero-based projection. It is formed from two distinct activities: (1) completion of its baseline assessments of approximately 1,320 miles of pipeline; and (2) performance of the reassessments for all of its 1,149 HCA miles.

Table SCG-RKS-9
SoCalGas TIMP Program Assessment Summary

TIMP Pipeline Segment Assessment Category	2003 - 2009 Completed	2010 Forecast	2011 Forecast	2012 Forecast
A. Baseline Assessments (miles)	840	189	92	45
B. Re-assessments (miles)	25	47	93	84
C. Pipelines in Casings (count)	0	15	83	91

SoCalGas is forecasting the funding necessary to meet its TIMP obligation as set forth in 49 C.F.R. § 192.901 Subpart O. Specifically, SoCalGas will require an additional $13,799,000 for funding its ongoing TIMP-related activities above its adjusted recorded 2009 expenditures. Although there are industry average values available, SoCalGas cannot rely on a historical or average expense to forecast these costs because there is no history to accurately depict the work for TIMP activities that are taking place for the very first time, such as cased main assessments.

Finally, the magnitude of the TIMP costs is also due to SoCalGas' size. SoCalGas ranks 22nd among the nation's DOT Transmission pipeline operators with 3,989 transmission pipeline miles. Yet, SoCalGas ranks as the highest operator of HCA miles in the nation with 1,149 miles. SoCalGas has 168 miles more HCA pipeline than the Williams Gas Pipeline (Transco). Williams Gas Pipelines, ranked third in the nation with 981 HCA miles as compared to SoCalGas, but Williams is one of the largest Transmission pipeline operators with approximately 8,700 miles. SoCalGas' size and location of operations has a direct and significant bearing on overall costs to comply with TIMP requirements including, but not limited to, the fact that it has the greatest number of HCA miles in the nation. Using the same DOT data set[13] for the top eleven Transmission operators in the U.S., excluding SoCalGas, averaging their HCA miles would result in 603 miles per operator. This is about half of SoCalGas' approximately 1,149 HCA miles. Therefore, industry averages or industry average costs do not adequately represent SoCalGas.

SoCalGas' TY 2012 forecast is a zero-based approach using units of work to best describe its costs. Based on that methodology and evaluating the remaining work to comply with TIMP, SoCalGas is forecasting $24,760,000 for TY 2012. This is an increase of $13,799

[13] Ranking based upon DOT's 2009 report of mains and services found http://ops.dot.gov/stats/DT98.htm.

over its 2009 adjusted recorded expense. It represents the additional work for reassessments and the complexity to assess cased main.

Pipeline Integrity Management—Distribution

As noted earlier, the second branch of pipeline integrity affects SoCalGas' distribution system and is known as the Distribution Integrity Management Program (DIMP). PHMSA published a final rule that amended the federal pipeline safety regulations to require operators of gas distribution pipelines to develop and implement a pipeline integrity management program. On December 4, 2009, the DIMP rule was posted as: Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines; Final Rule, 74 Fed. Reg. 63,906-63,936 (codified 49 C.F.R. pt. 192).

PHMSA's purpose for DIMP is to enhance pipeline safety by having operators identify and reduce pipeline integrity risks specifically for distribution pipelines.

As a gas distribution operator, SoCalGas has developed a DIMP plan and will continually modify it as it enhances its system knowledge and identifies threats. SoCalGas' DIMP must conform to the specific elements contained in the regulations. To enhance safety for the distribution system, SoCalGas is identifying and reducing pipeline integrity risk. As a prudent operator, SoCalGas has developed a risk-based computational model in which engineering-based algorithms evaluate different distribution pipeline attributes to help analyze and to risk rank them. Based on the risk ranking, SoCalGas will take mitigation measures to reduce the threat, thus enhancing the integrity and safety of its distribution system.

Table SCG-RKS-10
O&M Non-Shared Services—Pipeline Integrity Distribution
(Thousands of 2009 dollars)

ENGINEERING			
C. Pipeline Integrity - Distribution (Subpart P)	**2009 Adjusted-Recorded**	**TY2012 Estimated**	**Change**
1. Distribution Pipeline Integrity (Refundable 2009-2011, Base Margin 2012)	6,570	31,097	24,527
Total	**6,570**	**31,097**	**24,527**

DIMP history and overview

It is important to have a background on the drivers for DIMP. DIMP has roots in the previously discussed TIMP. To gain a perspective and better understand SoCalGas' approach, a discussion on the genesis of DIMP is provided. DIMP is the integrity management requirements for DOT-defined distribution pipe and facilities. DIMP is a broad program that encompasses an operator's entire system rather than a targeted area, such as HCAs.

The impacts of the DIMP regulations are significant for SoCalGas because it is the largest operator of distribution main and services in the country. SoCalGas has over 47,650 miles of main and approximately 48,640 miles of services that are covered under Subpart P. In its normal course of business, and as a prudent operator, SoCalGas performs activities to monitor and maintain the integrity of distribution lines as required by the federal pipeline safety regulations Subparts A-N. These core requirements are addressed in the Prepared Direct Testimony of Ms. Gina Orozco-Mejia, Exhibit SCG-02, and are not shown here. DIMP-driven activities are above and beyond SoCalGas activities to meet the core regulatory requirements. The DIMP plan is to leverage and build upon these existing activities. This is the approach PHMSA had in mind when it crafted its integrity management regulations governing distribution. Specifically, the approach is one of integrating system performance data to drive additional and accelerated actions to increase safety.

In response to this regulatory requirement, SoCalGas took initial steps and developed a Pipeline Integrity blueprint for its DIMP. Details of SoCalGas DIMP and non-shared activities are provided in this section of my testimony. SoCalGas has taken a judicious approach with its DIMP by reviewing its current activities and prudently looking to leverage them to mitigate threats. By doing this, SoCalGas has balanced program costs while delivering on DIMP compliance. The IM plan must address seven specific elements[14] as follows:

1. Knowledge of system;
2. Identify threats;
3. Evaluate and rank risk;
4. Identify and implement appropriate measures to mitigate risks;

[14] 49 CFR 192.1007.

5. Measure performance, monitor results, and evaluate effectiveness;

6. Periodic evaluation and improvement; and

7. Report results.

It must be noted that, although DIMP addresses certain activities SoCalGas has always performed, DIMP requires a significant increase in those activities beyond SoCalGas' traditional core regulatory obligations, which are addressed by the Prepared Direct Testimony of Witness Ms. Gina Orozco-Mejia for Gas Distribution, Exhibit SCG-02. The DIMP activities described in this section are distinct and go beyond SoCalGas' traditional core obligations.

Because DIMP is comprehensive, covering all of an operator's distribution system, SoCalGas is approaching it with a balanced mindset to enhance safety and reliability. However, SoCalGas will meet DIMP mandates by prudently applying the knowledge and experience gained from TIMP to keep costs as low as possible.

SoCalGas is very mindful of the magnitude of the DIMP program costs. These costs are significant, driven primarily by SoCalGas' relative size and the expanse of its system[15]. To illustrate its size, if SoCalGas were a state, based on the number of miles of main would make it the sixth largest state in the nation.

Apart from its sheer size, SoCalGas' costs are higher than PHMSA's estimated industry-average program unit costs. SoCalGas specifically commented on the cost estimates PHMSA provided in its development of the rule because PHMSA's estimates appeared much too low. SoCalGas based those comments on experience gained through years of managing the core regulatory requirements on its distribution and transmission pipeline systems. Just one example is SoCalGas' mitigation activity to address pipeline leakage. As part of its DIMP-driven mitigation measures, SoCalGas is forecasting the need for funds to address leakage threats by replacing non-state–of-the-art pipe. PHMSA reports that the average cost for a large operator (there are 201 large operators in the PHMSA report[16]) to replace bare steel pipe could be from $53 to $77 per foot, a range of almost 1.5 times the low estimate. SoCalGas'

[15] PHMSA web site: http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.ebdc7a8a7e39f2e55cf2031050248a0c/?vgnextoid=a872dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print.

[16] Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines; Regulatory Impact Analysis: Final Rule, PHMSA-RSPA-19854, October 29, 2007.

experience shows that in its service territory the actual range could be as much as three times the low estimate. This comparison illustrates that installation costs are much higher for SoCalGas than for the industry average, which significantly impacts its DIMP program costs. SoCalGas' higher installation costs are due to the fact that its service territory encompasses many different areas with high population density (Class 3 and 4 locations), special traffic considerations, environmental requirements, etc., that cause costs for installing pipe, and performing various field activities, to be greater than the average across the country. In addition, PHMSA states that it expects the group of 201 large operators to collectively replace 17.5 miles of bare steel main per year. That is equivalent to only 460 feet of pipe to be replaced per operator. In order to address the DIMP threat of leakage, SoCalGas is proposing a more robust replacement rate which again drives up the program cost estimates. This more aggressive approach to threat mitigation is required by the intent of the DIMP rule.

To minimize costs as much as possible, SoCalGas' basic approach is to leverage its existing mitigation programs to meet DIMP safety mandates. This means improving in those areas that make sense for the SoCalGas system. This approach is consistent with PHMSA intent as shown by the following statement:

These [DIMP] regulations require that operators of these pipelines develop and follow individualized integrity management (IM) programs, in addition to PHMSA's core pipeline safety regulations. The IM approach was designed to promote continuous improvement in pipeline safety by requiring operators to identify and invest in risk control measures beyond core regulatory requirements.[17]

As noted by PHMSA, DIMP requires activities beyond those required by traditional regulation. Activities that are part of the company's routine work (core regulatory requirements) cannot be counted as part of DIMP. SoCalGas therefore is creating an individualized DIMP that will include activities that are above and beyond its core regulatory requirements. SoCalGas is augmenting its existing programs to meet DIMP mandates and PHMSA's stated objective to do more than the status quo.

To comply with the DIMP mandates, SoCalGas has assembled a variety of programs which are further discussed in my testimony. In this testimony and specifically where appropriate, I will identify those incremental DIMP activities that might seem similar to the

[17] Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines; Final Rule, 74 Fed. Reg. 63,906 (posted Dec. 4, 2009) (codified 49 C.F.R. pt. 192).

routine and normal course of business (core regulatory requirements), but are above and beyond the existing core safety requirements. I will also discuss the methodology of the forecasts and the threat that the activity addresses that is mandated by DIMP.

DIMP-Program Management Office

One of the first action items has been the establishment of the DIMP program management office. Since SoCalGas and SDG&E have taken a related-operator approach, the discussion of this specific activity is detailed in my shared-services testimony. The related-operator approach means combining and considering both utilities' assets as one with respect to regulation impacts.

DIMP-Driven Activities

SoCalGas has developed a compendium of programs to meet the DIMP mandates while balancing cost considerations. The DIMP-driven activities are as follows:

Geographical Information System (GIS) work—DIMP mandate: "Know your system"

Distribution Risk Evaluation And Monitoring System (DREAMS)—DIMP mandate: "Know, evaluate, and risk rank threats";

DIMP-Driven Monitoring—DIMP mandate: "Know and evaluate threats";

AnodeLess (A/L) Riser Program—DIMP mandate: "Mitigate threats";

Vehicular Damage—DIMP mandate: "Mitigate threats";

Sewer Lateral Initiative—DIMP mandate: "Mitigate threats".

Damage Prevention —DIMP mandate: "Mitigate threats".

Geographical Information System (GIS)

SoCalGas has embarked on a process to enhance its understanding of the gas distribution system ahead of the final DIMP rule based on two considerations: knowledge and experience gained from the TIMP program; and the multi-year efforts of various industry and governmental committees, workshops, and reports which collected, analyzed, and disseminated information in the lead-up to the DIMP notice of proposed rulemaking. During the development of the DIMP rule, it became evident that a comprehensive GIS would be needed to effectively manage the DIMP requirements. This has enabled SoCalGas to accomplish several objectives in its quest for additional system knowledge as required by the DIMP regulations.

This initial step is providing additional knowledge to more readily identify threats, to assess them, and to prioritize them. Specifically, SoCalGas has taken existing data and integrated that information into a single electronic repository that can readily and graphically depict the information. In order to achieve this goal, it was necessary to bring together numerous existing paper records and data within many stand-alone data collection/maintenance systems in core regulatory activities. Ongoing costs associated with the GIS development for SoCalGas Gas Distribution are forecasted to be $4,973,000 in 2010 and $5,716,000 in 2011. Additional discussion of these expenses is provided in the Prepared Direct Testimony of Witness Mr. Richard D. Phillips for Operational Excellence (OPEX 20/20), in Exhibit SCG-13. Some of the system attributes or elements SoCalGas is collecting and analyzing include the following: pipeline location, material composition, pipe size (diameter), joining methods, construction methods, date of installation, soil conditions (where appropriate), operating and design pressures, maintenance history, operating experience performance data, overall condition of the system, and other characteristics. This information is found in several data sources at SoCalGas including system maps (atlas sheets), construction records, work management systems, corrosion records, operating and maintenance records, and personnel who have knowledge of the system. This is a voluminous collection of information that SoCalGas is in the final steps of integrating.

Once the GIS phase is complete, SoCalGas can then move to more rigorous and comprehensive data analysis and threat identification. From there, risk-ranking and preventative measures can be executed. SoCalGas is forecasting additional funding in TY 2012 to enhance its GIS to improve its capability to evaluate and mitigate threats as required by the DIMP regulations. The completion of GIS will be performed in phases to accommodate the integration of the many different sets of data involved, ultimately producing a single repository. The work to complete the GIS is extensive and continues through 2011. The most significant activity is the conversion of approximately 35,000 atlas sheets from paper records into electronic files. These atlas sheets represent over 20,000 square miles of SoCalGas services territory.

In addition to the final conversion efforts, SoCalGas has identified several enhancements to GIS that will leverage the GIS system and increase its value. SoCalGas is forecasting additional funding in TY 2012 to build on its GIS with additional enhancements that will enable it to continually improve its capability to evaluate data. The evaluation will enhance knowledge, analysis, and threat identification.

One such enhancement involves Cathodic Protection (CP) polygons that can be created electronically and more efficiently under GIS. A CP polygon is simply an area outlining a contiguous set of pipelines that are part of a single CP area. Currently, that work is performed manually. With the data included in GIS, electronic traces can be conducted to verify that the CP polygons are correct, areas that need follow-up work can be identified, and CP integrity can be better enforced.

Other GIS enhancements will affect the integration of the management of foreign data and data bases. An example of a foreign data base is Geofields, a GIS data base that contains both general and unique attributes of high-pressure pipelines that depict portions of Distribution and Transmission systems. However, this data is not easily integrated into the linear GIS data model used for both medium and high pressure pipelines. The integration of these data is necessary to prevent the possibility of developing conflicting data between the databases as system changes and maintenance occurs. This integration of the GIS data will also enable further and better analysis of the pipeline system. Because of the numerous service lines in SoCalGas, and the fact that SoCalGas is an amalgamation of many gas companies over the decades which had different approaches to records, this integration is particularly difficult. Reconciling the data and adding back missing information will greatly help SoCalGas evaluate its system and risk rank pipeline segments as required by DIMP.

One other challenge to GIS is an issue of Boundary Conflation. It is a technique to align data. Conflation is required when two map layers that were captured independently with different accuracy need to be reconciled to represent a consistent map product. As an example, when street centerlines from two different digital sources are displayed, there will be a significant variation in the spatial placement of the centerlines. This is akin to the shift in placement of land base from Company-maintained data to vendor-provided data. During the GIS conversion project, SoCalGas has captured gas facility data relative to the new vendor-provided land base; however, Company boundaries used for operations, such as atlas sheet tiles and Region Boundaries need to be "conflated" to align with the new vendor-provided land base.

These are just a few of the more significant activities that must be completed to provide a GIS data set that will enable SoCalGas to use the full capabilities of the system. By converting the paper records into a single electronic repository, SoCalGas will more effectively and systematically evaluate its pipelines. It will then have the capacity to enhance its knowledge of the pipeline system and help it more effectively mitigate threats.

The GIS activities described for SoCalGas DIMP will require a TY 2012 amount of $4,285,000 using a zero-based forecasting methodology.

<u>Distribution Risk Evaluation And Monitoring System</u>

The next incremental request is associated with SoCalGas' computational model to support SoCalGas' DIMP mitigation strategy. This activity primarily aligns efforts to meet the DIMP requirements for "evaluate and risk-rank threats", while also addressing other requirements such as system knowledge, identify and implement appropriate measures to mitigate risks, and performance measures. This computational model helps evaluate and risk-rank pipeline threats associated with leakage on a pipeline segment. The ultimate mitigation is the replacement of the segment; however, the models results can also be used to implement intermediary activities which will be further explained below. This model is called the Distribution Risk Evaluation And Monitoring System (DREAMS). As a computational model, DREAMS evaluates many risk factors associated with non-state–of-the-art pipe regardless of material. SoCalGas' distribution pipeline system is composed of either steel or plastic pipe. There are approximately 17,000 miles of non-state–of-the-art pipe in the system. For plastic pipe, "non-state-of-the-art" refers to early vintages of plastic pipe that has proven to be less reliable than currently available products. Under certain conditions, these pipes tend to fail prematurely and thus are candidates for replacement. For steel pipe, "non-state-of-the-art" refers to bare pipe without cathodic protection. As they are identified, each non-state–of-the-art pipe segment and its associated attributes are being methodically catalogued within DREAMS.

DREAMS is a cornerstone of our DIMP efforts because it helps meet several DIMP mandates—Knowledge of the system, Evaluation, Analysis and Risk-Ranking of pipeline threats. By design, DREAMS accounts for many pipeline attributes that facilitate pipeline-leakage identification such as material type, joining method, maintenance history, proximity, age, and other factors to account for the risks this pipeline segment poses. Accounting for all of these variables which contribute to a pipeline segment's threat, and applying sound engineering principles, DREAMS evaluates and assigns a risk score to each pipeline segment. In general terms, the risk score represents known, repaired leakage history associated with a pipeline segment. The higher the DREAMS risk score, the greater the consequence could be if the segment were to develop future leakage. The pipe segment has already proven to be susceptible to leakage due to its known leakage history and thus is a candidate for replacement to prevent the threat from reoccurring. Segments with the highest risk scores would be priority candidates for replacement.

As the risk-scored segments are catalogued within DREAMS, a 100-point threshold is applied to identify those segments that qualify for mitigative activities. Any pipeline segments above this threshold would be earmarked for DIMP replacement. Pipeline segments below the threshold remain in the database, their associated dataset updated as new information becomes available. This additional data can come from a number of sources, most notably through the current GIS data conversion effort. Information from paper maps and a variety of hard-copy historical files are reviewed and all pertinent pipe attribute data is entered into DREAMS. As the data gets updated, if a score exceeds 100 the segment would become eligible for replacement.

SoCalGas continues to build its DREAMS inventory of pipeline segments. Once complete, DREAMS will contain enough basic data to enable the ongoing assessment and associated threat reduction for the entire distribution system.

In summary, DREAMS is an efficient approach to help comply with many of the seven DIMP elements. Specifically, DREAMS increases knowledge of the system, identification, analysis and risk ranking of threats. It also facilitates the mitigation of the threats by risk scoring them, which establishes a priority list placing the ones with the highest risk, score first. DREAMS enables a more measured and analytical approach because of its use of enhanced knowledge of the pipeline system. It is a key tool in identifying segments for capital replacement. Although replacing pipelines as they reach the end of their useful lives is an activity SoCalGas has undertaken as a prudent operator and part of its core regulatory requirements, replacing pipe as a DIMP mitigation measure must go beyond the present activity level to comply with the regulations; "*The IM approach was designed to promote* *continuous improvement in pipeline safety by requiring operators to identify and invest in risk control measures beyond core regulatory requirements".*[18]

Under the non-shared umbrella, no additional funding is requested for DREAMS. However, it does drive capital activity, namely pipeline replacement. SoCalGas is forecasting capital under BC 277 – Distribution Integrity Management Program. This capital expenditure is explained in the capital portion of my testimony, Section IV.

DIMP-Driven Monitoring

DIMP-Driven Monitoring (DDM) addresses the realities and challenges of construction that prevent SoCalGas from replacing non-state-of-the-art pipeline segments as prioritized under DREAMS. These challenges are often from construction moratoriums imposed by cities. These moratoriums prevent pipe replacements and can delay execution of SoCalGas' DIMP mitigation strategy to replace a non-state-of-the-art pipeline. Ideally, SoCalGas can approach the DREAMS risk-ranked segment in a linear fashion and mitigate the highest priority risk-ranked pipe segments systematically. However, due to various issues outside SoCalGas' control, such as city street construction moratoriums, protracted permit processing, and other issues, not all segments can be immediately replaced as defined by the DREAMS risk-ranking. To address this issue, SoCalGas will deploy a DIMP-driven monitoring program. This surveillance will provide the needed assurances that pipe segments that are not replaced under schedule are closely monitored for indications of accelerated deterioration. This added monitoring will be accomplished through additional and accelerated leakage surveys.

This DIMP-driven activity should not be confused with the core regulatory requirement discussed in the Prepared Direct Testimony of Ms. Gina Orozco-Mejia, namely leak surveys. SoCalGas has determined that augmenting this activity would be prudent under DIMP because it balances the need for added monitoring with an existing practice. Thus, SoCalGas avoids the costs to implement an entirely new surveillance approach to meet the DIMP mandates.

The DIMP-driven monitoring is estimated at $574,410 for TY 2012 using a zero-based forecasting methodology.

[18] Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines; Final Rule, page 63906 Federal Register / Vol. 74, No. 232 / Friday, December 4, 2009 / Rules and Regulations.

Anodeless Riser Program

Another threat with a potentially high consequence should a failure occur is Anodeless (A/L) risers. A/L risers are a service line component that has shown a propensity to fail before the end of its useful life. The consequence of this component failing can be significant in that A/L risers are attached to the meter set assembly (MSA), which is usually located next to a residence. There are approximately 2,600,000 A/L riser units that have the potential to be an integrity threat due to premature failure.

Such failure can be induced in at least one of three ways. The first is from above-ground leakage due to atmospheric corrosion – Polyethylene (PE) A/L risers have a demonstrated propensity toward atmospheric corrosion just below the stopcock in the gas-carrying steel nipple portion of the assembly. The root cause of such corrosion is usually environmental conditions that result in a constant or frequent presence of moisture. The environmental moisture factor can be compounded in some A/L riser designs by the presence of shrink sleeves and ID tags that can trap and retain moisture against the surface of the steel making them less tolerant to moisture exposure. The second cause of accelerated failure is from compromised MSA installation from loss of structural integrity of riser casing. This can result in movement of the MSA, loosening threaded connections, and thus causing possible thread leaks. Although the risk is considered to be low, the consequent can be high. The third cause of accelerated failure is below-ground leakage due to corrosion from low-set risers. A low-set riser can result if an MSA is installed at a depth that causes the riser to be buried. The low-set riser should be buried in such a way as to keep the exposed gas-carrying steel above ground level, thus avoiding the need for CP. When risers become incorrectly buried, the corrosion threat must be mitigated by replacing the riser. In new housing tracts, this situation can occur because, although the initial installation had placed the riser at the correct depth, over time and through a myriad of landscaping and other homeowner-driven activities, the steel portion became buried.

SoCalGas has been involved in research to develop an effective means of mitigating the above-ground and ground-level corrosion on A/L risers. This effort has lead to the implementation of the Trenton Wax Tape solution, which provides an effective protective barrier of the above-ground section of the riser in the severe environmental conditions that are typical of riser installations. This approach enables SoCalGas to arrest the active corrosion without replacing the risers. This effective mitigation measure will accomplish two goals.

First, it will minimize the corrosion threat upon application, and second it will prolong the life of the riser without the added expense of replacement. Risers that do not pass the evaluation and those found leaking will be replaced. Based on a preliminary analysis, SoCalGas estimates that approximately 15% of the risers will ultimately qualify for replacement, while the remaining units will be effectively mitigated with the Trenton Wax Tape.

As part of its core regulatory requirements, SoCalGas has been addressing this threat. Under the DIMP mandate, SoCalGas will augment the core activity to further minimize the threat A/L risers present. SoCalGas plans to mitigate the threat over a 7-year period. The funding reflects an average of 193,000 A/L risers processed per year. This increase in activity complements the existing work in distribution, but adds sufficient resources beyond those efforts. SoCalGas' rationale for augmenting the ongoing activity is based on PHMSA's requirement that operators go beyond their routine work.

SoCalGas is estimating $15,033,000 in TY 2012 for this incremental activity. The forecasting methodology was zero-based and driven by units of work to complete the program goal in seven years.

<u>Vehicular Damage Associated with Above-Ground Facilities</u>

SoCalGas has identified another potential threat to its system through the experience obtained from TIMP and its understanding of the federal pipeline safety regulations. 49 CFR Part 192 has two specific sections addressing vehicular damage for Transmission main and for Distribution customer MSAs. The specific code sections are 49 CFR 192.317(b) and 49 CFR 192.353(a) for Transmission main and Distribution MSAs, respectively. SoCalGas addresses damages associated with vehicular damage. However, under the DIMP, operators are required to go beyond the core regulatory requirements when addressing known threats. Therefore, SoCalGas is embarking on a DIMP-driven program to address potential vehicular damage associated with above-ground distribution facilities

SoCalGas has conducted a preliminary assessment to identify all SoCalGas above-ground pressurized gas facilities located within a 50-foot radius of any corner of a street or highway intersection, or other intersecting transportation pathways intended for routine vehicular traffic. The identified facilities were then evaluated for risk of severe vehicular collision. The level of risk depended on the likelihood of a gas component being struck and the predicted effectiveness of protective barriers currently in place at each site. Factors affecting this risk assessment involved proximity to the intersection, speed of traffic, and the design and quality of existing barriers. The survey was divided into three parts: Distribution facilities, Transmission facilities, and residential MSAs. Approximately 2,100 potential above-ground Distribution and Transmission facilities were identified, and 72 were evaluated as being at high/moderate risk of severe vehicle collision should a vehicle leave the road and strike the facility at high speed. Approximately 145,000 potential residential MSAs were identified, and approximately 10,500 of those MSAs were determined to be at high/moderate risk of severe vehicle collision should a vehicle leave the road and strike the MSA at high speed.

Although SoCalGas has existing design standards to address the protection of facilities due to vehicular damage under the code, it is not sufficient to protect facilities for vehicular damage where the vehicle leaves the road at a high rate of speed. In addition, the re-design of existing meter protection standards may be warranted as SoCalGas gains additional knowledge from this project. Finally, this is a DIMP activity because vehicular damage is a threat and while the projected incident rate is low, the consequences can be high. This low-frequency, high-consequence event is the type of threat PHMSA intended to address when it developed DIMP regulations.

To address vehicular damage to company facilities, SoCalGas will identify, evaluate, recommend, and then implement a damage prevention solution. SoCalGas has developed a collection of mitigation measures to effectively address this threat. The collection of mitigation measures include, constructing barriers (bollards or block wall), relocating the facility, or installing an Excess Flow Valve (EFV) to mitigate the threat.

For TY 2012, SoCalGas is forecasting $2,252,000 for this activity, $606,000 in Labor and $1,646,000 in non-labor, using a zero-based methodology.

<u>Sewer Lateral Inspection Program (SLIP)</u>

The last of the DIMP mitigation initiatives is the Sewer Lateral Inspection Program (SLIP) to address an emerging issue concerning pipeline damage associated with sewer laterals. This DIMP-driven mitigation measure aims to effectively address this potentially significant integrity issue.

The integrity threat comes from the use of trenchless technology during installation of pipelines, when an errant installation creates a cross bore. A cross bore occurs during the installation of the pipeline using trenchless technology (boring or directional drilling) when the auger (the tip of the trenchless technology) accidently crosses a misplaced sewer lateral and consequently penetrates, or bores, through all or a portion of it. The damage to the sewer lateral can create an immediate blockage or a blockage that slowly and progressively worsens depending on the encroachment of the gas pipeline. At some point in time, the cross bore can create sufficient blockage to clog the drains so that the sewer line needs to be unplugged. A plumber or the property owner unknowingly uses a cleanout technology, such as a sewer-line auger, to clean out what is seemingly normal sewer debris and blockage. The sewer line appears to be unclogged, but in reality the sewer-line auger has pierced the gas line. Depending on how extensive the damage caused by the sewer-line auger, the gas line, which has now been breached, will leak gas into the sewer line and elsewhere. This unwanted gas migration can have significantly high consequences both in damage to property and persons.

Both the vehicular damage program and SLIP address the concerns PHMSA expressed under DIMP, requiring operators to address these identified threats of low frequency but potentially high consequence.[19]

As general background information, trenchless technology is an installation method that employs technology to enable the installer, in this case the utility, to install pipe underground without disturbing as much pavement and concrete as the open-trench method. This bored-in installation method has the advantage of less impact to the streets, pavement, dirt, etc., which translates into lower installations costs. It is a common and well-established technology. In fact, because the technology has less impact to the pavement and streets, the American Public Works Association regularly sponsors workshops to promote its use. SoCalGas' use of this technology is a prudent and cost-effective measure. To assure proper installation, investigative work takes place in advance of the trenchless technology being deployed. This investigative work includes, but is not limited to, ensuring underground substructures are located and marked and potholed (depth checks). These activities are common construction practices for many industries.

Although the inception and deployment of this technology for use in plastic pipeline installation started in the early 1970s, the concern with cross bores has only become an industry-wide focus since the late 2000s. At that point, SoCalGas revised its Gas Standard

[19] Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines; Final Rule, 74 Fed. Reg. 63,906 (posted Dec. 4, 2009) (codified 49 C.F.R. pt. 192, section 192.007(c)).

(installation policy) to ensure that cross-bore situations would not occur prospectively. However, as a prudent operator and adhering to DIMP principles and as noted earlier in this testimony, SoCalGas has developed an initiative to inspect and cure cross bore situations that exist within its distribution system.

SoCalGas recognized this issue as a potential threat based on the investigatory work Southwest Gas (SWG) performed and presented to the industry. SoCalGas used the SWG information to analyze and project the number of potential cross bore situations that may exist in its distribution system for plastic pipe installed with trenchless technology. The number of potential situations SoCalGas forecasts and will pursue is 410. These 410 potential situations, or conflicts, are projected based on analysis of the directional drilling projects completed in the time period from 1970 through 2006 and the expected frequency for conflicts. The number of conflicts is low, but this threat presents the high consequence of damage, as noted by SWG, industry, and state and federal pipeline safety representatives. The consequences were further underscored by a tragic incident that occurred in St. Paul, Minnesota, on February 1, 2010, when a sewer contractor attempting to unclog the sewer line with a cutting tool cut the natural gas line and, as a result, gas was released into the sewer and into the home. The gas then ignited, injuring the contractor, and the resulting fire destroyed the home.

To address the threat posed by SLIP, SoCalGas is taking a two-step approach to first identify the conflicts, and then, as a second step, mitigate them. This two-step approach would be performed over a five-year period commencing in 2010. SoCalGas forecasts its TY 2012 costs for SLIP to be $7,503,700. The forecast was developed using a zero-based methodology and units of work.

<u>Damage Prevention and DIMP activities</u>

One of the leading threats to distribution piping systems is damage caused by third parties. Often this type of damage is due to construction contractors performing excavation activities in the vicinity of our gas infrastructure and damaging the pipeline or components. While SoCalGas actively executes its existing damage prevention program, damage to mains and services still happens.

To further enhance damage prevention efforts, SoCalGas is requesting six additional FTEs to augment the existing damage prevention program. Four of these additional positions would be allocated to the Distribution Regions, one to each Region, and be responsible for leading a renewed focus on damage prevention activities. These efforts will lead to more effective surveillance of the system and help to define enhancements to the damage prevention program.

To support the increased field activities, two staff positions are required to perform these new additional duties. One position will be placed in Pipeline Integrity. The Pipeline Integrity Engineering position will collect and analyze data to develop trends and help identify areas where additional resources may be required. The second position will be located in Claims Management. One of the many activities within the Claims Management department is to monitor system damage through claims data and identify contractors who damage our pipe system with elevated frequency. The intent of this additional position is to provide more frequent and aggressive interactions with these contractors to drive down third party damage occurrences. These six positions will be Technical Advisor level positions. The TY2012 expense requirement will be $450,000.

Additionally, the following system program enhancements will be implemented to further address the DIMP rule requirements specifically by addressing damage and leak prevention.

Pipe locating – The initial focus will be in standardizing the operating regions with the latest technology in pipeline locating equipment. There are a number of approved makes and models of pipe locating equipment in use. This effort will be to ensure that the best-fit technology is utilized by the locating personnel. In conjunction with the technology review and update, an industry expert will be utilized to review training materials, lesson plans, and field training scenarios to ensure training is current and effective, specific to damage prevention. This activity will include a survey and incorporation of best practices as necessary. An additional product will be the development of a comprehensive roll-out training regimen capable for use at both the Pico Rivera training facility and remote field locations that involve replicating difficult but realistic locating scenarios and the associated trouble-shooting techniques. Initial and ongoing refresher training is important to maintain this highly skilled staff. The estimated annual expense for this three-year program is approximately $240,000.

Additional / Accelerated leakage survey on high-pressure distribution mains - Under enhanced Damage Prevention practices, SoCalGas will perform annual leakage survey activities on all high-pressure distribution lines. This activity will target distribution mains that do not meet the definition of a DOT transmission line but due to their operating characteristics are risk ranked higher than the medium-pressure distribution network system. Additionally, due to their operating characteristics, SoCalGas has determined that performing leak survey activities on these lines, similar transmission lines, provides a greater assurance of pipeline safety and reliability. Second, it will provide another opportunity for pipeline surveillance to help with the identification of potential damage by unreported excavations adjacent to our pipelines. This accelerated activity will modify the leak survey cycle of approximately 1,300 miles of high-pressure distribution main from five- and three-year cycles to annual survey cycles. The estimated annual expense for this enhancement is approximately $170,000.

Pipeline marking and patrol of high-pressure distribution main – This is another routine activity that is being augmented to create greater visibility of certain high-pressure pipelines. Under this activity, SoCalGas will install pipeline markers on all high-pressure pipelines where such markers are not currently mandated in 49 CFR §192. This activity will require the identification of the target lines, communication with cities and counties to acquire appropriate agreements and/or permits, and installation of line locator devices. The program will include recording the GPS location of installed markers to facilitate ongoing maintenance and patrol activities. This will require modifications to GIS to include the GPS location and SAP for patrol scheduling. Additionally, this program will require increases in ongoing warehouse stock of line markers for normal O&M activities. This three-year program will address approximately 1,875 miles of high-pressure distribution main at an estimated TY2012 expense of $283,000.

Additional / Accelerated leakage survey on medium pressure steel mains without cathodic protection. Under enhanced leak management and damage prevention practices, SoCalGas will increase the frequency of leakage surveys of medium-pressure distribution mains without cathodic protection located in business districts. This activity will target those pipe segments that may be more susceptible to leakage and are located in areas of higher public activity. SoCalGas has determined that performing these accelerated leak survey activities provides a greater assurance of pipeline safety and reliability. In addition, it provides another opportunity for pipeline surveillance to aid in the identification of potential damage by unreported excavations adjacent to our pipelines. This program enhancement will affect approximately 2,400 miles of distribution main, converting from annual to semi-annual leakage surveys. The estimated annual expense is $312,000.

DIMP Summary

The compendium of work to identify and mitigate integrity threats is estimated to cost approximately $31,100,000 as shown in Table SCG-RKS-10. The change in this account is driven by the DOT mandates to enhance the safety, reliability, and integrity of SoCalGas' distribution system. SoCalGas has embraced the precepts of the program, and SoCalGas has taken a prudent approach by using analytical methods and sound engineering principles to comply with DIMP regulations. The forecast relies on a zero-based methodology because historical trending or averaging is not appropriate. Each of these initiatives is necessary to meet the DIMP mandates. These activities go beyond core regulatory requirements and address threats that may be low in frequency but high in consequence, which go to the heart of PHMSA's objectives for DIMP. Meeting PHMSA's objectives will allow SoCalGas to enhance the safety, reliability, and integrity of its system.

Public Awareness Program

SoCalGas has developed and implemented the federally mandated Public Awareness (PA) program as prescribed in 49 C.F.R. § 192.616. PHMSA's goal under PA is to improve public awareness of pipeline operations and safety issues through enhanced communications with various stakeholders, which includes the public and emergency officials.[20] Further, this program includes the identification of the various customers and non-customers located within a certain radius of SoCalGas' transmission or storage facilities. From the identification process and type of affected party, the program prescribes the method for meeting the communications requirements. To effectuate such a large plan, the PA program involves multiple organizations within SoCalGas which requires coordination and management executed within Gas Engineering. The federal regulations are prescriptive as to the types and frequency of required communications. Two additional essential elements are required: tracking of these communications, and evaluation of the messages for resonance and impact. To comply, SoCalGas is required to communicate safety messages to various targeted audiences in its territory. This includes customers, non-customers in the distribution territory, residents along the route of transmission facilities, emergency and public officials, and excavators. The

[20] Public Safety: Pipeline Operator Public Awareness Program; Final Rule, 70 Fed. Reg. 28833-28842 (posted May 19, 2005) (codified 49 C.F.R. pts. 192, 195).

program prescribes specific messages, delivery methods, and frequency of communications to each targeted audience.

Table SCG-RKS-11
O&M Non-Shared Services—Public Awareness
(Thousands of 2009 dollars)

ENGINEERING			
D. Public Awareness (FERC 859.3)	**2009 Adjusted-Recorded**	**TY2012 Estimated**	**Change**
1. Public Awareness	307	1,159	852
Total	**307**	**1,159**	**852**

As mandated by 49 C.F.R. § 192.616, each operator is to measure the impact of their PA messages. PHMSA incorporated American Petroleum Institute's Recommended Practice 1162 (APR RP 1162), so operators must comply with it. One of the action items under API RP 1162, Section 8.4, "Measuring Program Effectiveness," is to undertake measurement of how the PA program safety messages are received. This measurement will require surveys of certain groups to determine how, and to what extent, the PA messages are reaching them. The increased costs shown here reflect the increased funding associated with greater and more frequent safety messages to the affected stakeholders. The methodology used to forecast costs is based on the SoCalGas' current practices used in its communication department. Also the forecast reflects the cost of assessing the various markets SoCalGas serves, tailoring the message to those stakeholders, and assessing the effectiveness of the messages. The additional communications and measurement efforts significantly increase the costs over 2009. The biggest cost driver is publicizing key messages in the expensive Los Angeles/major Southern California media markets.

PHMSA's most recent workshop[21] held on June 30, 2010 in Houston emphasized several key items which are as follows:

- Have a PA plan;
- Complete the effectiveness surveys;
- Review and evaluate results;
- Identify gaps; and

[21] PHMSA's Public Awareness workshop, June 30, 2010.

- Continually improve PA by using the completed surveys.

If the initial assessment survey finds gaps in conveying the messages, the operator must address them or improve the communication process. Part of the challenge for SoCalGas will be effectively reaching its diverse customer base. There are multiple languages, myriad media outlets, and lifestyle choices affecting SoCalGas' ability to reach the stakeholders required by PHMSA.

SoCalGas is forecasting for its TY 2012 $1,159,000 for this activity over its 2009 adjusted-recorded expenses. This is a zero-based methodology using activities.

<u>Summary</u>

Several activities were discussed in this section of my testimony. The first was the core engineering and staff functions that supports customer services, distribution, transmission, and storage operations with project management; engineering policies, analysis, testing, design, geographic products, measurement, regulation, and control evaluation and expertise, pipeline and system protection, computer operations technology services, project planning and construction management services, and system analysis and forecasting. These activities ensure a prudent and sound engineering discipline to meet SoCalGas' core obligations.

The second area presented in this section was the compulsory activities driven by federal and state mandates that affect Transmission, Distribution, and Storage. SoCalGas has taken a prudent approach to address pipeline integrity management mandates in a cost-conscious manner. SoCalGas has leveraged its experience and existing activities to balance requirements and costs. The magnitude of some programs is directly proportional to SoCalGas' sheer size as one of the largest natural gas pipeline operator in the nation. Finally, SoCalGas compendium of DIMP programs to address pipeline threats and mitigate them successfully is necessary to meet PHMSA's requirements. Some of these DIMP-driven activities augment existing programs to reduce costs but are incremental to historical activity. PHMSA stated in the DIMP final rule: "The ultimate goal is to improve safety. Improvement cannot be realized without change."[22]

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[22] Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines; PHMSA Response to Comment Topic 16(b), 74 Fed. Reg. 63,918 (Dec. 4, 2009).

III. SHARED SERVICES

A. Introduction

Scope and Purpose of Shared Services Testimony

The purpose of this section of my testimony is to demonstrate that the following Shared Services O&M expenditures are reasonable and should be adopted by the Commission. The expenditures discussed in this section include Gas Engineering O&M expenditures in support of Gas Distribution and Transmission operations at both SoCalGas and San Diego Gas & Electric Company (SDG&E). These O&M expenditures represent the Gas Engineering support for gas pipelines, compressor stations, and regulator and measurement stations. The expenses also include the compliance cost for two pipeline integrity programs as well as the state's GHG regulations. Because SoCalGas personnel support both utilities, their associated labor and non-labor expenses must be allocated between both. This section will discuss cost allocation between the two utilities and the material changes in shared service expenses in TY 2012 compared to 2009 adjusted recorded expenses.

These forecasts are responsive to the philosophy of achieving operational excellence to meet core regulatory, and new safety, and emerging environmental requirements, while providing safe, reliable delivery of natural gas to customers at the lowest possible cost. This testimony respectfully requests the Commission adopt the TY 2012 shared-services forecast of $15,919,000 ($2009). The request is an increase of $3,628,000, over 2009 adjusted recorded costs. The SoCalGas shared service expenses, and the amounts billed by SDG&E to SoCalGas for shared services, are shown in Table SCG-RKS-12. Cost centers that have shared expenses are described within this section of testimony. In addition, this testimony provides forecasting methodology, changes in spending, and cost allocation methodology. A discussion of the billed-in expense (received) from SDG&E is also provided.

The methodologies to allocate costs vary within the shared services testimony. The methodology will vary based on the type of activity. This helps ensure that costs are appropriately allocated. There are predominantly two basic approaches employed. The first one is based on total meters between the two utilities. This equates to an allocation of 86.4% to SoCalGas and 13.6% to SDG&E, and this methodology is used when the activities are related to gas measurement. The second basic methodology to allocate costs is based on the pipeline miles. When the activities are related to pipeline work, such as the pipeline integrity programs, this methodology is used. The allocation, when all pipeline miles are involved for Transmission and Distribution, equates to 85.8% for SoCalGas and 14.2% for SDG&E.

Table SCG-RKS-12
O&M Shared Services
(Thousands of 2009 dollars)

ENGINEERING			
	2009 Adjusted-Recorded	**TY2012 Estimated**	**Change**
Incurred Costs (100% Level)			
A. General Engineering	9,110	10,106	996
B. Pipeline Integrity	3,657	6,565	2,908
C. Pipeline Integrity - Distribution IMP	222	402	180
D. Pipeline Design & Gas Standards	689	756	67
Incurred Costs Sub-Total	**13,678**	**17,829**	**4,151**
Allocations Out To SDG&E			
A. General Engineering	783	849	66
B. Pipeline Integrity	441	865	424
C. Pipeline Integrity - Distribution IMP	32	59	27
D. Pipeline Design & Gas Standards	86	86	0
Allocations Out To SDG&ESubTotal	**1,342**	**1,859**	**517**
Allocations Out To Unreg			
A. General Engineering	45	51	6
B. Pipeline Integrity	0	0	0
C. Pipeline Integrity - Distribution IMP	0	0	0
D. Pipeline Design & Gas Standards	0	0	0
Allocations Out To Unreg SubTotal	**45**	**51**	**6**
Retained by SCG			
A. General Engineering	8,282	9,206	924
B. Pipeline Integrity	3,216	5,700	2,484
C. Pipeline Integrity - Distribution IMP	190	343	153
D. Pipeline Design & Gas Standards	603	670	67
Billed in from SDG&E	86	134	48
SCG Retained Sub-Total	**12,377**	**16,053**	**3,676**

B. Summary of Shared Services Activities

1. General Engineering

Table SCG-RKS - 13
O&M Shared Services
(Thousands of 2009 dollars)

ENGINEERING			
A. General Engineering	**2009 Adjusted-Recorded**	**TY2012 Estimated**	**Change**
Incurred Costs (100% Level)			
1. Engineering Design	1,122	1,369	247
2. Gas Measurement, Regulation & Pressure Control	4,880	5,218	338
3. Engineering Analysis Center	1,180	1,466	286
4. Asset and Data Management	1,316	1,256	-60
5. Planning & Analysis	612	797	185
Incurred Costs Sub-Total	**9,110**	**10,106**	**996**
Allocations Out To SDG&E			
1. Engineering Design	43	63	20
2. Gas Measurement, Regulation & Pressure Control	538	598	60
3. Engineering Analysis Center	22	26	4
4. Asset and Data Management	167	145	-22
5. Planning & Analysis	13	17	4
Allocations Out To SDG&ESubTotal	**783**	**849**	**66**
Allocations Out To Unreg			
1. Engineering Design	0	1	1
2. Gas Measurement, Regulation & Pressure Control	45	50	5
3. Engineering Analysis Center	0	0	0
4. Asset and Data Management	0	0	0
5. Planning & Analysis	0	0	0
Allocations Out To Unreg SubTotal	**45**	**51**	**6**
Retained by SCG			
1. Engineering Design	1,079	1,305	226
2. Gas Measurement, Regulation & Pressure Control	4,297	4,570	273
3. Engineering Analysis Center	1,158	1,440	282
4. Asset and Data Management	1,149	1,111	-38
5. Planning & Analysis	599	780	181
SCG Retained Sub-Total	**8,282**	**9,206**	**924**

Billed-In From SDG&E	**0**	**0**	**0**
SCG Book Expense	**8,282**	**9,206**	**924**

Engineering Design, Cost Centers: 2200-0300, 2200-0318, and 2200-0321.

The cost center 2200-0300 represents the activities of the Director and the organization's administrative financial support functions for all the shared services activities SoCalGas provides. The Director provides the leadership, direction and policies for Gas Engineering for the benefit of both utilities. Expenses are typically for the technical and engineering support for gas transmission, gas distribution, and gas storage. The cost of this office, associated with support for Distribution and Transmission functions, is allocated to both utilities.

The Engineering Design group is comprised of the following cost centers: 2200-0318 and 2200-0321. These cost centers represent the mechanical, civil and process design activities that support both utilities.

Activities provided by Engineering Design are the policy development and implementation of distribution capacity planning and specific technical engineering support for design. This centralized approach assures consistency across the operating groups. The design, technical, and mechanical engineering support for SoCalGas' and SDG&E's compressors are also provided. SoCalGas operates about 213,000 horsepower of compression, while SDG&E operates about 15,500 horsepower. The compression assets are a vital and integral part of gas operations.

There is a small allocation to the unregulated business for the mechanical engineering design services this workgroup provides. This is in recognition of work that is performed from time to time. A five-year average was used to forecast this engineering activity.

Within this work group is structural and seismic activity support. This group is forecasting an increase of $200,000 in TY 2012 to cover a new program that complements existing seismic work. The goal is to enhance the seismic work currently performed by implementing a program that will provide SoCalGas and SDG&E with the ability to direct resources to the areas affected by seismic activity that have sustained damage. By pinpointing the locations of damages more quickly, resources can be more effectively managed during an emergency. Acquiring this capability is critical because both utilities operate in a well-known earthquake-prone environment and their exposure to risks associated with seismic activity needs to be closely managed.

By their very nature, transmission line and distribution supply line systems must cross areas that are subject to ground deformation from geologic and seismic events. Geologic and seismic hazards of fault rupture, liquefaction, and land sliding are common to southern California, and mitigating these hazards by avoidance is simply not an option in many areas. In addition, much of the SoCalGas transmission line and distribution supply line systems were installed prior to the modern understanding of the distribution and severity of these types of hazards. Therefore, a more complete understanding of the areas subject to these hazards is necessary. As such, SoCalGas will seek the services of companies specializing in aerial and spatial earth surface imaging and geologic and geotechnical engineering. These services will be used to: (1) identify where transmission lines and distribution supply lines cross areas subject to ground deformation from geologic and seismic hazards; (2) develop cost-effective strategies for prioritizing areas that require more detailed effort in order to characterize the hazard; and (3) provide recommendations for cost-effective mitigation options.

Finally, PHMSA's PA regulations are placing upward cost pressures on General Engineering activity. It is forecasted that, in TY 2012, an increase in managing and implementing new strategies and complementary polices impacting both utilities to increase awareness will be required.

The forecasting methodology used is the five-year average of 2005-09 because that best represents the day-to-day activities of this workgroup. The estimated TY 2012 forecast is $1,369,000. After employing the appropriate allocation methodology for each cost center, $63,000 is allocated to SDG&E while the booked expense for SoCalGas in TY 2012 is $1,305,000. The TY 2012 booked forecast represents an increase of $226,000 over 2009 adjusted recorded expenses. The five-year average which accounts for the ebbs and flows of the work from year to year is higher than the 2009 recorded adjusted expense. Another reason for the increase is associated with PA policy and strategy development. However, the largest driver is the increase to enhance the technical knowledge of, and emergency response related to, seismic activity.

Gas Measurement, Regulation & Pressure Control, Cost Centers: 2200-0309, 2200-0310, 2200-0311, 2200-0312, 2200-0799, and 2200-2248.

This branch of general engineering, the Gas Measurement, Regulation and Pressure Control (MRC) group, is comprised of the following cost centers: 2200-0309, 2200-0310, 2200-0311, 2200-0312, 2200-0248, and 2200-0799. The MRC activity is best represented by the grouping of these cost centers. The activities performed within the MRC group are many, but collectively the activities support both utilities in gas measurement and regulation for Customer Service, Distribution, and Transmission.

Cost Center 2200-0309 is the nexus because employees funded under this cost center provide for the general management and administrative support for approximately 75 employees and contractors performing work in the remaining cost centers. Collectively, these remaining shared services cost centers execute engineering policy, planning, design, testing and configuration, material selection, and field support related to measurement, gas regulation, automated control systems for pipelines and compressor stations, and other instrumentation for both SoCalGas and SDG&E. Special Engineering studies, regulatory filings and strategic planning are also performed. The diverse activities performed within the MRC workgroup are further discussed below. The MRC workgroup provides detailed engineering design, planning, policy, equipment standards, and consultation to operations related to: large meter and regulator stations, California producer gas facilities, interstate pipeline inter-connects, and pressure protection for pipelines and related automated controls. All centralized electrical and control system engineering associated with the design, operation, and the compliance and safety aspects of large gas handling facilities also reside within this cost center. Also included is the planning and technical support for the Natural Gas Vehicle (NGV) refueling stations, which was previously a non-shared service activity.

Responsibility for testing, evaluation, selection, approval, strategic and deployment planning, re-harvesting, and all policies and practices associated with gas metering equipment is performed within the MRC workgroup. These activities apply from the smallest residential diaphragm meter to the largest ultrasonic meters and electronic measurement equipment. Measurement accuracy and billing support is also provided. Specifically, the standards and planning for the measurement of gas quality associated with thermal zones (SDGE) and British Thermal Unit (BTU) districts (SoCalGas). The BTU district work performed includes reviewing the content of energy, as measured by on-line chromatographs and gas samplers across the utilities piping systems; and to ensure accurate and appropriate billing factors are used for more than six million customers each month. Another activity supported by the MRC workgroup is the preparation of monthly data reports detailing BTU district and pipeline hourly gas quality results which are to be delivered to the South Coast Air Quality District pursuant to its Rule 433.

The MRC workgroup is a specialized skilled workgroup. Use of its knowledge and expertise continues to be employed by the affiliates other than SDG&E. As such, there continues to be an allocation of the costs to provide this support. Approximately $45,000 has been allocated to affiliates, and SoCalGas expects this work will continue in the future. A five-year average was employed for the TY 2012 forecast.

Several adjustments have been made to the TY 2012 forecast, which are driven by increased work. One adjustment was organizational change to better align work with resources. The work to support NGV activity in SDG&E necessitated the reassignment of NGV station engineering from a non-shared service account to a shared service account in 2009.

Another adjustment is an increase related to the work caused by the implementation of OSHA's National Fire Protection Association (NFPA) 70 Arc-Flash regulation. To implement this regulation, the group was required to document, train facility personnel, and review certain electrical facilities throughout the operations. The Arc-Flash work will be an on-going activity which will require additional resources. There are over 2000 electrical panels in SoCalGas and SDG&E facilities and operations subject to Arc-Flash conformance. It is estimated over 100 of these panels will require an annual inspection due to load and panel circuitry changes in 2010-2012. Accordingly, SoCalGas forecasts an additional $40,000 per year in engineering labor and $10,000 in associated non-labor cost for tools, training, and travel (for site visits to electrical panels across the two companies).

Because MRC has responsibility for the design of measurement and regulator stations, MRC has forecasted additional engineering resources to address each of 200 stations (above normal activity level) per year commencing in 2011 and extending into 2012. Therefore, additional resources are forecasted to perform the incremental work of $50,000.

The preliminary California Producer Access ruling, with its proposed one-hour interval for gas quality averaging to enforce quality provisions for gas entering SoCalGas pipelines (A.

04-08-18) will increase the work load by requiring additional site visits and programming of the 40 producer sites. Looking forward, there will be more resources required to monitor and manage producer gas quality consistent with SoCalGas Rule 30. The forecasted increase is about $80,000. The other need for incremental resources is to perform the work associated with a recent adoption of South Coast Air Quality District (SCAQMD) Rule 433. The forecasted increase for perform these activities is approximately $170,000.

The TY 2012 costs are best forecasted using the five-year averages of costs from 2005-09, since it best depicts the activity and accounts for variation in work from year to year. To account for the increase, the added work was estimated and combined with the five-year average to form the forecast. Thus, the TY 2012 incurred expense forecast for the MRC group is $5,218,000. After allocating the appropriate expense to SDG&E of $598,000, using primarily the number of meters between the two utilities, the TY 2012 booked expense for SoCalGas is $4,570,000, which is an increase of $273,000, over 2009 adjusted recorded expense.

Engineering Analysis Center-Chemical Section, Cost Center: 2200-1178.

The Engineering Analysis Center (EAC) Chemical Section provides environmental, gas quality, odorization and BTU measurement-related analytical services. BTU measurement is the energy content determination of natural gas. This is a vital function because this determination is used to help render accurate customer bills. The environmental work performed involves analysis of pipeline liquids, such as determining if the pipeline contains Poly-Chlorinated Biphenyls (PCBs). Another important function carried out within this workgroup is the odorization management of the natural gas system in compliance with DOT Safety regulations (49 C.F.R. § 192.625 “Odorization of Gas”). Due to recent challenging efforts of mitigating “odor fade”, Gas Engineering, specifically the EAC, has determined that enhancements to the odorant blend of some gas supplies is warranted. The changes do not affect all locations, just those that contain primarily mercaptans. Thus, company field processes have been put in place to assist in addressing this condition. Beginning in 2011, SoCalGas will be supplementing its existing odorants as noted in the Direct Testimony of Mr. John L. Dagg in Exhibit SCG-03. The Tetrahydrothiophene (THT) will be added to the gas supplies which primarily contain Tertiary Butyl Mercaptan (TBM). The combination of the two will create a 50-50 blend of THT and TBM which will be consistent with the odorant makeup throughout most of SoCalGas' system. To facilitate the change, the EAC will require additional resources to monitor and assure this new blend will address the concerns of odor fade. In addition, SoCalGas is increasing its overall efforts to identify and address concerns of odor fade.

SoCalGas is forecasting additional labor and non-labor resources for equipment and consumables (such as calibration gases, gaskets, fittings, etc.) to provide the requested support for enhanced safety and to ensure an accurate customer bill by its BTU measurement activities.

The TY 2012 incurred expense forecast is $1,466,000. The forecast methodology that describes the day-to-day activities is the five-year average of 2005-09. To estimate the TY 2012 expense, the five-year average was used and modified to account for the aforementioned activities. The result was an increase of $286,000 for TY 2012.

The allocation methodology used to apportion the SDG&E component is based on the Cost Center Manager's determination using budgeted FTEs. The calculated percentage attributable in supporting SDG&E is 1.81%. The resulting booked expense for SoCalGas TY 2012 is $1,440,000, an increase of $282,000 over 2009 adjusted recorded base.

Asset and Data Management, Cost Centers: 2200-0302, 2200-0306, 2200-0307.

These cost centers were grouped to best reflect the activities performed in the Asset and Data Management area. These are activities that are user-specific and not performed by the Information Technology (IT) organization. The expenditures performed in this category include management of Operations Technology for administration, review, and publication of gas standards, Formal Communication Documents (FCDs), other company documents in SoCalGas' and SDG&E's on-line intranet websites. The workgroup performs operations-related technology development and implementation, and provides support for new and ongoing technical computing systems and applications. Specifically, the group creates and maintains intranet websites for various organizations including Safety, Distribution, Customer Service, Environmental, Transmission, and Engineering. These systems and applications include specialized engineering analysis applications, such as pipeline risk analysis. Another primary responsibility is the development and maintenance of a variety of web-based applications that support and manage the creation, publication, and maintenance of engineering gas standards, specifications, and SoCalGas and SDG&E procedures, and the electronic management of pipeline construction records.

The activities in this account have evolved over time and have been re-organized to align resources with work. Technology and the organization this cost center serves change with time; thus, the group has changed to meet the demand. The group was able to eliminate one position in 2010.

The base year 2009 adjusted recorded expense was the forecasting methodology used. This approach best captures the work performed and more accurately accounts for organizational changes to more effectively align work with resources. The one adjustment made was to account for the reduction in an FTE which was no longer needed. The net effect culminates in a TY 2012 incurred expense forecast of $1,256,000, which is a reduction of $60,000. The allocation methodology was based on the budgeted FTEs, which is about 11.5% to SDG&E. The TY 2012 booked expense for SoCalGas is $1,111,000. This is a decrease of $38,000 from 2009 booked expense.

Management Planning and Analysis, Cost Center: 2200-0323

The activity performed in this workgroup is the administration of the South Coast Air Quality Management District (SCAQMD) NOx RECLAIM credit portfolio. This program is an emission compliance program with a trading element to enable operators who fall under RECLAIM to buy and sell NOx credits. The program provides trading as one form of compliance. Operators under the program have the choice to install emission control technology to meet the compliance obligation or purchase NOx credits to meet their obligations. Because of the increases in regulatory requirements, such as AB 32 and GHGs requirements affecting both utilities mentioned in Section II of the non-shared services section of my testimony, additional resources are being forecasted.

The forecasting methodology that best depicts the activities in this cost center is the five-year average of 2005-09 to account for employee turnover from promotions and retirements. The difference between the five-year average and 2009 recorded adjusted expense is approximately $50,000. To account for the increase in activity from the new air quality mandates, an additional $125,000 has also been forecasted. In total, SoCalGas forecasts $797,000 for TY 2012. The allocation to SDG&E is based on two determinants, the number of meters between the two utilities and budgeted FTEs. This equates to an allocation factor of 2.14%. The TY 2012 booked expense for SoCalGas is $780,000, under this allocation.

2. Integrity Management Program, Cost Centers: 2200-2108, 2200-2109, 2200-0319, 2200-0320, , 2200-2291, 2200-2293, 2200-2297, and 2200-2325.

Table SCG-RKS-14
O&M Shared Services
(Thousands of 2009 dollars)

2. Pipeline Integrity	2009 Adjusted-Recorded	TY2012 Estimated	Change
Incurred Costs (100% Level)			
a. Pipeline Integrity	3,657	6,565	2,908
Incurred Costs Sub-Total	**3,657**	**6,565**	**2,908**
Allocations Out To SDG&E			
a. Pipeline Integrity	441	865	424
Allocations Out To SDG&ESubTotal	**441**	**865**	**424**
Retained by SCG			
a. Pipeline Integrity	3,216	5,700	2,484
SCG Retained Sub-Total	**3,216**	**5,700**	**2,484**
Billed-In From SDG&E	**0**	**0**	**0**
SCG Book Expense	**3,216**	**5,700**	**2,484**

The collection of cost centers represents the TIMP and general corrosion management activities performed on behalf of both utilities as discussed previously in Section II of my testimony. These activities are engineering and technical services performed in support of distribution and transmission operations for the safe, reliable, and efficient delivery of gas to both SoCalGas and SDG&E customers. The mission of the work performed and captured within these cost centers is to manage the policies and procedures associated with integrity management including TIMP and ensure integrity management requirements are properly reflected in policies and procedures owned by other departments. Prior to 2012, the shared costs associated with DIMP are being accounted for separately by Utility due to the requirements of the DIMP Balancing Account. Beginning in 2012, these DIMP program activities will also be shared. To comply with pipeline integrity regulations requirements, activities from specification of pipeline design and materials through ongoing maintenance activities are part of the program. These are not new activities, but are impacted in varying ways by the additional pipeline integrity requirements. As a result, program management activities, including the management of the Integrity Management Plans and related policies and procedures, are integrated and performed by the personnel charging their time to these shared cost centers.

The evolution of this workgroups' activity has resulted from changes in regulations as well as focus on new internal policy development and implementation. In addition, organizational changes have been warranted to better align resources with pending workload. For example, a newly formed cost center was created to dedicate resources to data management and mapping requirements solely for pipeline integrity purposes. This enables more accurate tracking of costs and allows the application of resources to the highest-priority projects. The activities performed within these cost centers are many, but collectively the activities support both utilities in the program management, policy and procedure development, analysis, and risk evaluation. The activities performed in this workgroup are primarily pipeline integrity management of new and existing pipeline infrastructure, most of which is underground. The group has provided technical engineering support to operations in the areas of:

- Pipeline Integrity Manager, Cost Center: 2200-2108;
- Integrity Assessment, Cost Center: 2200-2109;
- Corrosion and Direct Assessment, Cost Center: 2200-0319;
- Material and Quality, Cost Center: 2200-0320;
- Assessment Planning, Cost Center: 2200-2291;
- Preventative and Mitigative Measures, Cost Center: 2200-2293;
- Data Management and GPS, Cost Center: 2200-2297; and
- Pipeline Integrity/Ops-Tech Support, Cost Center: 2200-2325.

In response to integrity management regulations, the responsibility and activity of the organization have been expanded. The expenses are represented in account 2200-2108 (Pipeline Integrity Management).

This Cost Center is allocated based upon the percentage of transmission and distribution pipeline each utility operates out of the combined total miles of pipeline in the system. As noted previously, this equates to an allocation of 85.8% to SoCalGas and 14.2% to SDG&E.

3. Distribution Integrity Management Program, Cost Center: 2200-2295.

Table SCG-RKS-15
O&M Shared Services
(Thousands of 2009 dollars)

3. Pipeline Integrity - Distribution IMP	2009 Adjusted-Recorded	TY2012 Estimated	Change
Incurred Costs (100% Level)			
a. Pipeline Integrity Distribution	222	402	180
Incurred Costs Sub-Total	**222**	**402**	**180**
Allocations Out To SDG&E			
a. Pipeline Integrity Distribution	32	59	27
Allocations Out To SDG&ESubTotal	**32**	**59**	**27**
Retained by SCG			
a. Pipeline Integrity Distribution	190	343	153
SCG Retained Sub-Total	**190**	**343**	**153**
Billed-In From SDG&E	**0**	**0**	**0**
SCG Book Expense	**190**	**343**	**153**

a. Distribution Integrity Management Program

The activities in this cost center support the work for the Distribution Integrity Management Program (DIMP). The activities include the work associated with a program management office (PMO) to effectively develop and manage the DIMP for both SoCalGas and SDG&E. Initially, the activities will focus on the development of policy, direction, and guidance and will work closely with those involved in TIMP. Leveraging the experience gained from the development and implementation of TIMP will facilitate a more effective program and minimize costs. The activities will also include working with subject matter experts and policy holders to initiate mitigation measures to address the identified threats. As noted in the non-shared services section of my testimony, some of the threats and mitigation measures can be sensibly achieved by augmenting existing programs. Addressing threats in this manner provides a cost-effective way to address them. With time, the activities and work will evolve as has been SoCalGas' experience. Also, this workgroup's activities include special projects needed to further program goals.

A base-year approach was used as the forecast methodology. The 2009 adjusted recorded costs best represent the costs of these activities for TY 2012 since this is a new program with little recorded history. SoCalGas has been actively reviewing the DIMP regulations and its current core activities to see what can be augmented to meet DIMP threat identification and mitigation mandates. SoCalGas has identified the need for two additional positions to provide program management duties associated with the DIMP-driven evaluation and mitigation measures previously discussed. This shared service arrangement enables both companies to avoid duplication of costs and reap the benefits of consistency and knowledge. This increase in resources equates to $180,000 over the 2009 adjusted recorded incurred expense.

The 2009 adjusted recorded booked expense by SoCalGas was $190,000. The cost allocation method employed was on pipeline mileage of mains and services of both utilities. This equates to approximately 14% allocated to SDG&E. Therefore, the TY 2012 estimated booked expense is $343,000 for SoCalGas, which is an increase of $153,000 over 2009 adjusted recorded expense.

C. Pipeline Design & Gas Standards, Cost Center: 2200-0322.

Table SCG-RKS-16
O&M Shared Services
(Thousands of 2009 dollars)

D. Pipeline Design & Gas Standards	2009 Adjusted-Recorded	TY2012 Estimated	Change
Incurred Costs (100% Level)			
1. Pipeline Design & Gas Standards	689	756	67
Incurred Costs Sub-Total	**689**	**756**	**67**
Allocations Out To SDG&E			
1. Pipeline Design & Gas Standards	86	86	0
Allocations Out To SDG&ESubTotal	**86**	**86**	**0**
Retained by SCG			
1. Pipeline Design & Gas Standards	603	670	67
SCG Retained Sub-Total	**603**	**670**	**67**
Billed-In From SDG&E	**0**	**0**	**0**
SCG Book Expense	**603**	**670**	**67**

Within this cost center are the activities to ensure those individuals responsible for Gas Standards are kept abreast of regulatory changes to ensure the procedures they manage are in compliance. This group also develops and manages engineering gas standards, develops publishing criteria, ensures compliance with publication requirements, ensures review and revision of those standards governed by the O&M plan annually and other Gas Standards every five years. The gas standards comprise the policy and procedures which govern the design, operations, and maintenance of the transmission and distribution systems and are based on the relevant regulatory codes. This section has facilitated the integration of SoCalGas and SDG&E Gas Standards into single comprehensive documents. SoCalGas' Pipeline Design and Gas Standards group is the owner of all the engineering standards for the two utilities. Most of the SDG&E Gas Standards have been combined with those of SoCalGas into fully integrated standards.

As depicted in the historical data, the activity level for the Gas Standards group has been increasing. The increase is based on the additional scope of CPUC audits. The CPUC has increased the scope of audits to be more comprehensive. The result is increased work associated with the expanded scope. Based on current and estimated future work load, existing staff levels are adequate to effectively perform ongoing activities. Therefore, the base year 2009 forecasting methodology has been selected. For non-labor expenses, based on historical recorded data and estimates of future requirements, a four-year historical average was selected. There are no incremental increases requested beyond the forecasted values.

This Cost Center is allocated based upon the percentage of transmission and distribution pipeline each utility operates out of the combined total miles of pipeline in the system. As noted previously, this equates to an allocation of approximately 85.8% to SoCalGas and 14.2% to SDG&E.

SDG&E Expenses Billed Into SoCalGas, Cost Center: 2200-8920.

Billed from SDG&E to SoCalGas Gas Engineering for TY 2012 is $134,000 representing support services for Codes and Standards and for Mobile Data Terminals (MDTs).

The work performed supports the ongoing effort to develop, maintain, and revise gas standards (gas policies and practices) in accordance with federal, state, and local requirements in ensuring a safe and reliable delivery of natural gas. The other work performed supports SoCalGas employees' use of the MDTs. The specific activities performed are technical support and strategic planning. The technical support is for specialized applications such as KorTerra to enable MDT use of GIS map products on the job. Strategic planning is continually required to identify best practices and opportunities for improvement. This area involves implementation of large cross-functional projects and activities associated with Distribution and Transmission field technologies resulting from changes that improve the various field operations in this area.

The TY 2012 forecast is a $48,000 increase over 2009 adjusted recorded levels. The increase is expected due to the increased work in this area. SoCalGas has reviewed SDG&E's billed shared service expenses to SoCalGas from Cost Centers 2100-3563 and 2100-3699 and has concluded that these expenses are reasonable.

IV. CAPITAL

A. Introduction

The capital described in this chapter covers the capital expenditures estimated for SoCalGas' Transmission, Engineering, and Pipeline Integrity operations. The driving philosophy behind SoCalGas' capital expenditure plan is to provide safe, reliable delivery of natural gas to customers at the lowest reasonable cost. These investments also enhance the efficiency and responsiveness of SoCalGas' operations, and ensure compliance with all applicable regulatory and environmental regulations.

Upward pressure on capital costs is much the same as has been discussed for O&M. Examples include Budget Categories (or Codes) (BCs) 315 and 412 where, respectively, approximately $11 million is forecasted for 2011 and 2012 for retrofitting compressor stations to meet new AQMD Rule 1160 in the Mojave Desert. Also in this forecast are costs resulting from new rules related to construction of storm water runoff control measures in sediment-sensitive areas, and the cost of developing a "programmatic permit" to obtain long-term state and federal authorization to conduct operating, maintenance, and construction activities under the Endangered Species laws. A more modest example of upward cost pressure is due to the list of recommendations stemming from the Transportation Security Administration's (TSA's) 2009 audit of SoCalGas' critical facilities. Another area of increased capital costs is in BC 315 - Compressor Stations. Also reflected in the forecast is a new Gas Standard SoCalGas adopted in 2009 that implements the agreement the Company reached with Disability Rights Advocates (DiRA) related to sidewalk, walkway, or crosswalk work site egress by those physically or visually handicapped.

Work on retrofitting, inspecting and replacing Transmission pipelines has increased substantially since new federal pipeline integrity legislation was passed in 2002. As discussed in Section II of my testimony, TIMP is the principal driver of costs for BCs 276 and 312. Pipeline integrity costs are also included in BCs 318 and 402. Also included in these BCs are costs associated with replacement of pipeline sections to mitigate potential hazards from earthquakes and landslides.

Any replacement of pipeline segments required as a result of pipeline integrity assessments other than those under DIMP is included here, as is the cost of retrofitting pipelines to accommodate in-line inspection tools.

As discussed in Section II of my testimony, beginning in 2012, new DOT DIMP rules that apply to the Distribution piping system take effect and necessitate considerable increases in capital spending. The new rules apply to all segments of the Distribution system, including mains, services, meter assemblies and pressure regulating facilities. These costs are planned in, and will be recorded in, new BC 277. For each BC discussed below, the associated workpapers provide additional detail regarding justification and costs.

Table SCG-RKS -17
Capital Expenditures
(Thousands of 2009 dollars)

Category Description	2009 Recorded	2010 Estimated	2011 Estimated	2012 Estimated
1. 276 – Pipeline Integrity - Distribution	1,629	14,405	22,902	20,762
2. 277 – Distribution Integrity Management Program (DIMP)	0	0	14,262	30,224
3. 3X1 – Transmission Pipelines – New Additions	25,768	9,519	11,197	19,292
4. 3X2 – Transmission Pipelines – Replacements and Pipeline Integrity Program (PIP)	39,489	42,766	35,227	25,917
5. 3X3 – Transmission Pipeline – Relocations - Freeway	1,137	1,019	2,010	2,010
6. 3X4 – Transmission Pipeline Relocations – Franchise/Private	5,567	10,104	8,128	11,105
7. BC 3X5 - – Gas Transmission – Compressor Stations	2,514	2,303	5,407	19,257
8. BC 3X6 – Gas Transmission Pipelines – Cathodic Protection	836	2,413	1,793	1,793
9. BC 3X8 - – Gas Transmission – Meter and Regulator	5,609	8,777	4,526	4,526
10. BC 3X9 – Gas Transmission – Auxiliary Equipment	865	882	1,651	1,651
11. BC 617 - – Gas Transmission –	120	0	4,000	8,300

Pipeline Land Rights				
12. BC 730 – Gas Transmission – Laboratory Equipment	250	265	935	295
13. BC 736 – Gas Transmission & Storage – Capital Tools	862	307	307	307
14. BC 1001 – Gas Storage – S&E Direct Overheads	265	240	278	335
15. BC 1002 Gas Transmission – S&E Direct Overheads	894	904	1,046	1,260
16. BC 01100 – Gas Transmission – Coastal Region Conservation Program	134	886	664	0
17. BC 00399 – Sustainable SoCal Program	0	0	0	11,272
Total Capital:	**85,939**	**94,790**	**114,333**	**158,306**

B. Capital Request Detail

1. Budget Code 276

Table SCG-RKS-18
Capital Expenditures
(Thousands of 2009 dollars)

Description	2009 Adjusted Recorded	2010 Estimated	2011 Estimated	TY2012 Estimated
BC 276 - – Pipeline Integrity - Distribution	$1,629	$14,405	$22,902	$20,762

This BC was established in 2005 to record the costs of complying with a portion of new TIMP requirements contained in 49 C.F.R. § 192, Subpart O. As discussed previously, under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risks posed by these threats, assess the physical condition of their pipelines, and take actions to address potential threats and integrity concerns before pipeline incidents occur where possible.

As noted previously, pipeline inspections are performed using an internal electronic device that internally traverses the pipeline to collect information that is used to assess the pipeline. Many pipelines were not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow sufficient clearance for the tool during inspection. A typical retrofit may include replacing valves having restrictions with valves that allow inspection devices to traverse internally, insertion of tees with bars, and the change-out of bends and other fittings that may impede the progress of the inspection tool. These retrofit costs are in addition to the installation of the tool launcher and receiver typically installed near the time of inspection.

Once the retrofit is completed, the inspection tool is run, followed by excavations to validate the inspection findings and repairs, if needed. When it is more economical than retrofitting for compliance, a pipeline may be replaced or altered, if the construction can be implemented within the DOT-mandated assessment schedule. When possible, multiple pipelines may be combined into a single run and, conversely, a single pipeline may require multiple launcher and receiver points.

This forecast is the sum of approximately ninety specific pipeline projects each year. All of the larger projects appear on their own workpaper giving specific detail of that project. There are approximately 20 such workpapers for this activity. All of these projects are the result of a master schedule called a Baseline Assessment Plan (BAP) that ensures all subject pipelines meet compliance deadlines.

Construction cost estimates are based on experience gained working on projects of similar scope in similar settings.

2. Budget Code 277

Table SCG-RKS-19
Capital Expenditures
(Thousands of 2009 dollars)

Description	2009 Adjusted Recorded	2010 Estimated	2011 Estimated	TY2012 Estimated
BC 277 - – Distribution Integrity Management Program (DIMP)	$0	$0	$14,262	$30,224

This BC was established to record the costs of complying with a portion of new DIMP requirements contained in 49 C.F.R. § 192. Subpart P. As discussed previously, under this rule, operators of gas distribution pipelines are required to identify, evaluate, risk rank, and mitigate the threats to their pipelines. This forecast is based on the regulatory requirements to replace the identified system components at an accelerated rate.

DREAMS-driven main replacement - This spending represents pipeline replacement work that is incremental to routine replacement work and required to maintain system integrity, along with compliance with new DIMP regulatory requirements. Utilizing results from the DREAMS computational model, targeted replacement of non-state-of-the-art pipe includes approximately 21 miles ($13,672,000) in 2011, and 45 miles ($29,354,000) in 2012.

Vehicular Damage – Above-Ground Facilties - This includes spending focuses on mitigative activities associated with the threat of vehicular damage on facilities located within a 50-ft. radius of any corner of a street or highway intersection, or other intersecting transportation pathways intended for routine vehicular traffic. The identified facilities have been evaluated for potential risk associated with vehicular impacts. The annual cost and number of mpacted facilities mitigated are as follows:

2010: 64 facilities, $130,000;
2011: 348 facilities, $590,000;
2012: 512 facilities, $870,000.

3. Budget Codes: 301, 311, 321, 331

Table SCG-RKS-20
Capital Expenditures
(Thousands of 2009 dollars)

Description	2009 Adjusted Recorded	2010 Estimated	2011 Estimated	TY2012 Estimated
BC 3X1 - – Transmission Pipelines – New Construction	$25,768	$9,519	$11,197	$19,292

Transmission Pipelines – New Additions (BCs 301 and 311) include costs associated with the design and installation of new transmission pipelines to serve new customer loads and/or to improve the ability to move natural gas to points of critical need at adequate pressure. BC 311 contains SoCalGas' forecast of costs associated with specific projects.

New transmission pipeline additions are periodically required to increase capacity and meet the needs of new customers. 2009 adjusted recorded costs include billable projects - new pipeline additions which are paid for by entities other than SoCalGas according to SoCalGas' Tariff Rules. Because many new construction projects are initiated at the behest of potential customers of SoCalGas, the nature, size, and timing of these projects is based upon information that is available at the time of planning and budgeting.

Construction cost estimates are derived from experience with recent projects of similar pipe size, scope, and location.

Projects included in this estimate include:

- City of Palmdale Utility Electric Generating (UEG) Plant - $18.8 million over 2010, 2011 and 2012;
- Anaheim UEG Peaker Plant - $2.5 million over 2009 and 2010;
- Hydrogen Energy Plant – Standby fuel supply - $14.3 million over 2009-2013;
- North/South Interconnect – Line 6916 - $10.9 million over 2008, 2009, and 2010.

4. Budget Codes: 302, 312, 322, 332

Table SCG-RKS-21
Capital Expenditures
(Thousands of 2009 dollars)

Description	2009 Adjusted Recorded	2010 Estimated	2011 Estimated	TY2012 Estimated
BC 3X2 - – Transmission Pipeline replacements	$39,489	$42,766	$35,227	$25,917

Historically, BCs 302, 312, 322 and 332 have included the cost of replacing Transmission pipelines or pipeline sections found to have reached the end of their effective service lives through a combination of age, condition, or external threat such as landslides and/or natural disaster. Since 2002, costs in these BCs have been heavily influenced by the new federal pipeline integrity rules discussed in Section II of my testimony. Under these rules, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risks posed by these threats, collect information about the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

Expenditures associated with retrofitting and inspecting pipelines in High Consequence Areas (HCAs), as defined by the new Pipeline Integrity rules discussed above, are included in BC 312. Approximately 29 such projects, through 2012, are large enough to be discussed individually in detail in the workpapers for my testimony. Capital costs in BC 312 are lower in 2012 in part because replacements and retrofits to the Transmission system throughout SoCalGas' service territory found necessary during the first round of assessments are to be completed by the end of 2012.

5. Budget Codes: 303, 313, 323, 333

Table SCG-RKS-22
Capital Expenditures
(Thousands of 2009 dollars)

Description	2009 Adjusted Recorded	2010 Estimated	2011 Estimated	TY2012 Estimated
BC 3X3 - –Pipeline Relocations – Freeway	$1,137	$1,019	$2,010	$2,010

BCs 303 through 333 contain capital requirements associated with pipeline relocations periodically required by the California Department of Transportation (CalTrans) in connection with automotive freeway development. Capital requirements for Transmission pipeline relocations are difficult to forecast because they are dependent on projects managed by CalTrans and vary from year to year. The amount shown for 2010 is the budgeted amount for 2010. Forecasted costs shown for years 2011 and 2012 are the five-year average of recorded costs for years 2005 through 2009.

6. Budget Codes: 304, 314, 324, 334

Table SCG-RKS-23
Capital Expenditures
(Thousands of 2009 dollars)

Description	2009 Adjusted Recorded	2010 Estimated	2011 Estimated	TY2012 Estimated
BC 3X4 - – Transmission Pipelines – New Construction	$5,567	$10,104	$8,128	$11,105

Included in these BCs are expenditures associated with relocating transmission pipelines to accommodate planned private property development, street improvement projects other than freeways, and other work required due to right-of-way agreements and franchise requirements.

Projects in which the SoCalGas pipeline has prior rights, usually due to an easement or right-of-way, are collectible. Others are at SoCalGas' expense due to franchise requirements. Costs shown for this BC are based on known large projects. The biggest is for relocation of Lines 1016 and 4000 due to six railroad grade separation projects in Orange County. This project alone will cost approximately $13.6 million over years 2011 and 2012 and is not collectible. Another example is the relocation of Line 2000 to accommodate a warehouse expansion for the McMaster-Carr Corporation. It is estimated at $2.1 million, mostly in 2012, but is 100% collectible due to right-of-way requirements.

Cost estimates for large Transmission projects are based on recent, similar projects' recorded costs.

7. Budget Codes: 305, 315, 322, 335

Table SCG-RKS-24
Capital Expenditures
(Thousands of 2009 dollars)

Description	2009 Adjusted Recorded	2010 Estimated	2011 Estimated	TY2012 Estimated
BC 3X5 - – Gas Transmission – Compressor Stations	$2,514	$2,303	$5,407	$19,257

This BC includes the costs associated with installing and replacing compressor station equipment used in connection with SoCalGas' transmission system operations. The nature of compressor station operations requires the maintenance of facility reliability and safety. To keep operating costs down, reliance is placed on automation, remote control, and automatic data gathering systems to monitor performance data such as flows, pressures, and temperatures.

Compressor station equipment has a finite life requiring regular replacement and/or upgrade as recommended by manufacturers or as required by operating experience to maintain reliability and transportation availability for the SoCalGas service territory.

Forecasts for this series of BCs are based on a combination of recent experience and known, specific projects. Included in the latter for 2012 are:

Newberry Station controls upgrade	$3.4 million
Cactus City Station controls upgrade	$1.6 million (all years)
Ventura Station controls upgrade	$1.7 million
Desert Center Station controls upgrade	$1.7 million (all years)
Newberry Station Evaporative ponds	$3.6 million (all years)
Mojave Desert AQMD Rule 1160	$22.7 million (all years including 2013)

Also noteworthy in this BC is the inclusion of funds to address the findings of the TSA in a 2009 audit of critical gas Transmission facilities. Although relatively nominal at $170,000 in each year 2011 and 2012, it is a type of project not included in prior GRC proceedings.

8. Budget Codes: 306, 316

Table SCG-RKS-25
Capital Expenditures
(Thousands of 2009 dollars)

Description	2009 Adjusted Recorded	2010 Estimated	2011 Estimated	TY2012 Estimated
BC 3X6 - Transmission Pipelines – Cathodic Protection	$836	$2,413	$1,793	$1,793

This BC includes expenditures associated with the installation and replacement of Cathodic Protection (CP) equipment used to protect transmission pipelines against corrosion. Typical expenditures include replacement of surface anode beds and installation of new CP (rectifier) stations. These projects are mandated by federal and state minimum pipeline safety regulations and ensure the maintenance of adequate CP on Company pipelines.

CP is a system for preventing rust, corrosion, and pitting of natural gas transmission pipelines which may come into contact with water or soil or that encounter stray electrical currents in the surrounding soil. The CP system contributes to SoCalGas' ability to meet federal and state safety compliance requirements and maintain safe, reliable transportation of natural gas.

Forecasts for 2010 and 2011 are based on the known requirement to replace six anode beds, to install three new anode beds and additional amounts to provide for needs that arise during those years, based on experience. The forecast for 2012 is simply a repeat of 2011.

9. Budget Codes: 308, 318, 328, 338

Table SCG-RKS-26
Capital Expenditures
(Thousands of 2009 dollars)

Description	2009 Adjusted Recorded	2010 Estimated	2011 Estimated	TY2012 Estimated
BC 3X8 - – Gas Transmission – Meter and Regulator	$5,609	$8,777	$4,526	$4,526

These BCs include the capital cost of installing and rebuilding large meter set assemblies (MSAs) for transmission-served customers. They also include the instrumentation necessary for metering or regulating natural gas in connection with transmission operations and, in particular, costs associated with additions or replacements of station piping, valves, regulators, and control equipment at large metering facilities and pressure limiting stations located on the gas transmission system. These assets require replacement for three principal reasons: aging, change in use patterns, and/or population encroachment. Plus, there is the associated need to enhance the management of transmission system gas quality and capacity. Lastly, this section also includes costs for gauges, remote control and telemetry devices, and

Supervisory Control and Data Acquisition (SCADA)-related equipment located on the pipeline system, which are used for remote control and management of transmission facilities.

The forecast for 2010 is based on the operating budget for 32 specific projects. The largest of these are:

Pisgah Meter Station Improvement $1.0 million

Tesoro Refinery New MSA $1.2 million (collectible)

Exxon Mobil Refinery – Rebuild MSA $1.2 million

Blythe Energy MSA $2.4 million (all years) (collectible)

Forecast costs for years 2011 and 2012 are the five-year average of recorded costs in this BC in years 2005-2009.

10. Budget Codes: 309, 319, 329, 339

Table SCG-RKS-27
Capital Expenditures
(Thousands of 2009 dollars)

Description	2009 Adjusted Recorded	2010 Estimated	2011 Estimated	TY2012 Estimated
BC 3X9 - – Gas Transmission – Aux Equipment	$865	$882	$1,651	$1,651

This section shows expenditures related to the costs of equipment installed to support transmission system operations that are not captured in other BCs. For example, costs associated with the installation of telemetric and recording equipment to support transmission system operations would be assigned to this BC. Most expenditures are to upgrade or replace obsolete telemetric and/or recording equipment that supports transmission system operations.

The amount forecast for 2010 is based on the operating budget for these BCs. The forecasts for years 2011 and 2012 are the five-year average of costs experienced during years 2005-2009.

11. Budget Code 617

Table SCG-RKS-28
Capital Expenditures
(Thousands of 2009 dollars)

Description	2009 Adjusted Recorded	2010 Estimated	2011 Estimated	TY2012 Estimated
BC 617 - – Gas Transmission – Pipeline Land Rights	$120	$0	$4,000	$8,300

This BC includes costs associated with the acquisition of land and land rights necessary to conduct natural gas transmission activities.

New emissions regulations are expected to be enacted that impact SoCalGas' compressor stations at remote sites at North Needles, Newberry Springs, and Blythe. The regulations will further regulate air quality in sites immediately adjacent to pipeline compressor sites. The most cost-effective solution to the new regulations is ownership and control of the adjacent sites, especially when property values are relatively low. The plan is to purchase two sites in 2011 at approximately $2 million per site and one site in 2012 at $2 million.

Also included in this BC in 2012 is $6.3 million to purchase land in exchange for special permits issued by the United States Fish & Wildlife Services (USFWS) and California Department of Fish & Game (CDFG). These permits are required for pipeline construction and maintenance activities in lands under the provisions of the Endangered Species Act (ESA). Issuance of permits is contingent on the purchase of defined acreage and conveying title to a land management company affiliated with the USFWS. Such purchases are to be made up-front in 2012 to establish a "mitigation land bank" for use over a five-year period including 2012 while land costs are relatively low. The $6.3 million estimate is based on an expectation of a need of $1.25 million worth of mitigation land in each of the five years based on a five-year history of pipeline jobs in lands now covered by the ESA.

Another inclusion in this category is related to the ESA. It is found in this testimony in its coverage of BC 01100 covering the costs of development of a programmatic permit for routine operations and maintenance in the lands referenced above.

12. Budget Code 730

Table SCG-RKS-29
Capital Expenditures
(Thousands of 2009 dollars)

Description	2009 Adjusted Recorded	2010 Estimated	2011 Estimated	TY2012 Estimated
BC 730 – Gas Transmission – Laboratory Equipment	$250	$265	$935	$295

This BC includes costs associated with acquisition and replacement of tools and equipment for the Gas Engineering Analysis Center located in Pico Rivera, California. Such equipment has a normal service life of from five to seven years.

The forecast for 2010 is based on the operating budget for expected purchases in 2010. The forecast for 2011 is a repeat of 2010 plus $670,000 for purchases of new equipment specifically related to preparing for compliance with expected new GHG emissions regulations. The forecast for 2012 is the five-year average of recorded costs in this BC in the period 2005-2009.

13. Budget Code 736

Table SCG-RKS-30
Capital Expenditures
(Thousands of 2009 dollars)

Description	2009 Adjusted Recorded	2010 Estimated	2011 Estimated	TY2012 Estimated
BC 736 – Gas Transmission & Storage – Capital Tools	$862	$307	$307	$307

This BC includes costs associated with the purchase and replacement of capital tools used by the Transmission and Storage operating departments. Such tools include specialized welding equipment and GPS receivers used for land surveys.

The forecast for all three years is the five-year average of recorded expenditures in this BC between years 2005 and 2009.

14. Budget Code 1001

Table SCG-RKS-31
Capital Expenditures
(Thousands of 2009 dollars)

Description	2009 Adjusted Recorded	2010 Estimated	2011 Estimated	TY2012 Estimated
BC 1001 – Gas Storage – S&E Direct Overheads	$265	$240	$278	$335

This BC provides for funding of Supervision & Engineering overheads that are allocated over capital BCs.

Forecasts are based on a five-year average of recorded costs in 2005-09 and are then aligned with the overall trend in capital labor expected in Transmission & Storage capital categories during the forecast period.

15. Budget Code 1002

Table SCG-RKS-32
Capital Expenditures
(Thousands of 2009 dollars)

Description	2009 Adjusted Recorded	2010 Estimated	2011 Estimated	TY2012 Estimated
BC 1002 Gas Transmission – S&E Direct Overheads	$894	$904	$1,046	$1,260

This BC provides for funding of Supervision & Engineering overheads that are allocated over capital BCs.

Forecasts are based on a five-year average of recorded costs in 2005-09 and are then aligned with the overall trend in capital labor expected in Transmission & Storage capital categories during the forecast period.

16. Budget Code 01100

Table SCG-RKS-33
Capital Expenditures
(Thousands of 2009 dollars)

Description	2009 Adjusted Recorded	2010 Estimated	2011 Estimated	TY2012 Estimated
BC 01100 – Gas Transmission – Coastal Region Conservation Program	$134	$886	$664	$0

This BC includes the cost of developing a programmatic permitting approach to obtain federal and state approval under the ESA to conduct routine SoCalGas operations and maintenance in the Counties of San Luis Obispo, Santa Barbara, Ventura, Los Angeles, Orange, San Bernardino, and Riverside. The term of the agreement is to be fifty years.

17. Budget Code 0399

Table SCG-RKS-34
Capital Expenditures
(Thousands of 2009 dollars)

Description	2009 Adjusted Recorded	2010 Estimated	2011 Estimated	TY2012 Estimated
BC 0399 – Sustainable SoCal Program	$0	$0	$0	$11,272

As discussed in Section II of my testimony, SoCalGas proposes to install four BioEnergy units at certain customer sites for the purpose of capturing raw biogas and upgrading it to pipeline quality biogas (biomethane). This project will advance the market development efforts associated with producing pipeline quality biogas from digested raw biogas generated from wastewater treatment plants, dairies, and food processing plants.

SoCalGas plans to install the first two BioEnergy units in the third-quarter of 2012, and two additional units will be installed after TY 2012. Each installation of a BioEnergy unit at a producer site will require an estimated capital investment of approximately $5.6 million to cover the costs related to the equipment purchase, interconnection, site specific feasibility study, required permits, and other installation costs including contractors' fees.

SoCalGas estimates the biogas market potential to be 34 million standard cubic feet per day (MMscfd), 55 MMscfd, and 3 MMscfd respectively; the majority of this biogas is currently an untapped source of sustainable energy. Because of its expertise and corporate values, SoCalGas is positioned to play a leadership role in advancing the use of biogas while supporting the objectives of both AB 32 and Executive Order S.06-06 by providing California and its ratepayers with significant environmental and economic benefits by helping to reduce GHG emissions.

Please refer to the testimony of witness Gillian A. Wright for policy and business justifications supporting SoCalGas' biofuels market development efforts.

V. CONCLUSION

The forecasts of the O&M expenses and planned capital expenditures represented in my testimony balance compliance obligations with costs enabling SoCalGas to continue to deliver natural gas safely and reliably.

The forecast increases are driven overwhelmingly by compliance obligations. These obligations are rooted either at the federal level as with TIMP and DIMP or at the state level with enactment of AB 32. These regulatory-driven costs represent almost 97% of the increase in the non-shared services and 72% of the shared services, which is about $49,000,000 and $2,600,000, respectively.

Balancing the compliance requirements with costs was important to SoCalGas. SoCalGas identified ways to leverage experience and knowledge to minimize cost impacts such as augmenting existing core programs. It also has taken a measured approach to address the highest priorities first using a risk-based philosophy.

In summary, these forecasts reflect sound judgment and represent the significant impact from legislative mandates to enhance public safety. The Commission therefore should adopt the forecasted expenditures discussed in this testimony.

This concludes my prepared direct testimony.

VI. WITNESS QUALIFICATIONS

My name is Raymond K. Stanford. My business address is 555 W. Fifth Street, Los Angeles, California. I am employed by SoCalGas as the Engineering Design Manager in Gas Engineering for SoCalGas and SDG&E. In this position, I am responsible for providing centralized gas infrastructure design engineering and technical utility support to operations for distribution, transmission, and storage. To accomplish this responsibility, I manage an organization of approximately 30 employees with technical expertise in specific engineering fields.

In addition, I possess a broad background in engineering and natural gas pipeline operations with over 25 years of experience with SoCalGas. I have held a number of managerial positions with increasing responsibility in the Engineering, Distribution, and Transmission Departments. I have been responsible for various areas related to the design, construction, operation, and maintenance of natural gas system facilities. I have held my current position as Engineering Design Manager since January 2008.

I earned a Bachelor of Science degree in Chemical Engineering from California State Polytechnic University, Pomona, and have completed the Masters in Business Administration from the University of Redlands, School of Business.

I have not previously testified before the Commission.