Company: San Diego Gas & Electric Company (U902M)
Proceeding: 2016 General Rate Case
Application: A.14-11-XXX
Exhibit: SDG&E-07

SDG&E

DIRECT TESTIMONY OF MARIA T. MARTINEZ

(PIPELINE INTEGRITY FOR TRANSMISSION AND DISTRIBUTION)

November 2014

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

A Sempra Energy utility®

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SUMMARY

TIMP & DIMP			
Shown in Thousands of 2013 Dollars	**2013 Adjusted-Recorded**	**TY2016 Estimated**	**Change**
Total Non-Shared	7,409	11,484	4,075
Total O&M	**7,409**	**11,484**	**4,075**

TIMP & DIMP			
Shown in Thousands of 2013 Dollars	**Estimated 2014**	**Estimated 2015**	**Estimated 2016**
Total CAPITAL	**7,957**	**6,790**	**24,215**

- San Diego Gas & Electric Company's (SDG&E or the Company) Transmission Integrity Management Program (TIMP) is founded upon a commitment to provide safe and reliable energy at reasonable rates through a process of continuous evaluation and reduction of risks to transmission pipelines.

- The TIMP per 49 CFR Part 192, Subpart O, SDG&E is required to identifying threats to transmission pipelines in High Consequence Areas (HCAs), determine the risk posed by these threats, schedule assessments to evaluate these threats, collect information about the condition of the pipelines, take actions to minimize applicable threat and integrity concerns to reduce the risk of a pipeline failure, and report findings to regulators.

- Increased costs in 2016 are attributable to the continued expansion of SDG&E's ability to in-line inspect transmission pipelines, the use of new technology and the replacement of certain early-vintage distribution pipelines.

- The funding level requested for the TIMP is reasonable and required to meet the requirements of 49 CFR Part 192, Subpart O.

- SDG&E's Distribution Integrity Management Program (DIMP) is founded upon a commitment to provide safe and reliable energy at reasonable rates through a process of continuous safety enhancement by proactively identifying and reducing pipeline integrity risks for distribution pipelines.

- Through the DIMP, under 49 CFR Part 192, Subpart P, SDG&E is required to collect information about its distribution pipelines, identify additional information needed and provide a plan for gaining that information over time, identify and assess applicable threats to its distribution system, evaluate and rank risks to the distribution system, determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline and evaluate the effectiveness of those measures, develop and implement a process for periodic review and refinement of the program, and report findings to regulators.

- The funding level requested for the DIMP is reasonable and required to meet the requirements of 49 CFR Part 192, Subpart P.

- Major O&M efforts, such as SDG&E's the Distribution Risk Evaluation and Monitoring System (DREAMS), are required to reduce overall system risk through proactive preventative and remediation activities in DIMP.

- The number of assessment and mitigation activities planned under TIMP and DIMP, which vary from year to year, is the main cost driver for these forecasts. Therefore, a zero-based forecast method is used.

SDG&E DIRECT TESTIMONY OF MARIA T. MARTINEZ
PIPELINE INTEGRITY FOR TRANSMISSION AND DISTRIBUTION

I. INTRODUCTION

A. Summary of Costs

I sponsor the Test Year 2016 (TY2016) forecasts for operations and maintenance (O&M) costs for non-shared and shared services and the capital costs for forecast years 2014, 2015 and 2016, associated with the Pipeline Integrity programs for Transmission and Distribution for SDG&E. Table MTM-1 summarizes my sponsored costs.

TABLE MTM-1
San Diego Gas & Electric Company
Test Year 2016 Summary of Total Costs

TIMP & DIMP			
Shown in Thousands of 2013 Dollars	**2013 Adjusted-Recorded**	**TY2016 Estimated**	**Change**
Total Non-Shared	7,409	11,484	4,075
Total O&M	**7,409**	**11,484**	**4,075**

TIMP & DIMP			
Shown in Thousands of 2013 Dollars	**Estimated 2014**	**Estimated 2015**	**Estimated 2016**
Total CAPITAL	**7,957**	**6,790**	**24,215**

In addition to this testimony, also refer to my workpapers, Exhibits SDG&E-07-WP (O&M) and SDG&E-07-CWP (capital) for additional information on the activities described here.

B. Summary of Activities

The SDG&E transmission system service territory covers the City and County of San Diego. Gas is received into the transmission system from Southern California Gas Company (SoCalGas) facilities through interconnection points at the San Diego/Riverside County border at Rainbow, California and at the San Onofre receipt point in San Clemente, California. The system is also designed to receive re-gasified Liquefied Natural Gas supplies from Transportadora de Gas Natural de Baja California S. de R.L. de C.V., a Mexican Pipeline Company, through an interconnection located in the community of Otay Mesa in San Diego.

The SDG&E gas distribution system consists of a network of approximately 14,052 miles of interconnected gas "mains" and "services" and 234 miles of transmission pipeline, as defined by United States Department of Transportation (DOT) regulations,[1] and 188 miles of High Consequence Areas (HCA). These mains and services, which are constructed of both steel and plastic materials in varying sizes, are located in most streets within SDG&E's service territory. The primary function of this distribution pipeline network is to deliver natural gas from SDG&E's transmission system to its customers in an over 1,400 square mile area that spans from Orange County in the north to the Mexico border in the south. Figure MTM-1, below, shows a map of the system.

Pipeline Integrity for Transmission and Distribution is responsible for implementing and managing the requirements set forth in 49 CFR Part 192, Subpart O—Gas Transmission Pipeline Integrity Management, and Subpart P— Gas Distribution Integrity Management. Under Subpart O, SDG&E is required to continually identify threats to its pipelines in HCAs, determine the risk posed by these threats, schedule and track assessments to address threats, conduct an appropriate assessment in a prescribed timeline, collect information about the condition of the pipelines, take actions to minimize applicable threats and integrity concerns to reduce the risk of a pipeline failure and report findings to regulators. SDG&E's TIMP has been designed to meet these objectives by continuously reviewing, assessing and remediating pipelines operating in HCAs and non-HCAs, in order to remain in compliance with federal regulations and provide safe and reliable service to its customers at reasonable rates.[2]

Under 49 CFR Part 192, Subpart P, operators of gas distribution pipelines operators are required to collect information about its distribution pipelines, identify additional information needed and provide a plan for gaining that information over time, identify and assess applicable threats to its distribution system, evaluate and rank risks to the distribution system, determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline and evaluate the effectiveness of those measures, develop and implement a process for periodic review and refinement of the program, and report findings to regulators. In contrast to the TIMP,

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1 *See* 49 CFR 192.3.

2 Although TIMP regulations currently only require baseline assessments of transmission pipelines operated in HCAs, in an effort to further enhance the safety and reliability of our system, SoCalGas has expanded its program to include assessments of non-HCA pipelines that are contiguous to or near HCA pipelines on a case-by-case basis.

DIMP focuses on the entire distribution system, not only pipelines operated in HCAs, since distribution pipelines are largely in developed, more-populated areas to deliver gas to those populations. SDG&E's DIMP is designed to meet these objectives to remain in compliance with federal regulations and provide safe and reliable service to its customers at reasonable rates.

C. Risk Management Practices in Pipeline Integrity Management Programs

Through its pipeline integrity programs, SDG&E continually evaluates the transmission and distribution systems, evaluates and ranks associated risks, and proactively takes action through inspections, replacements and other remediation activities to improve safety and reliability by reducing overall system risk. The risk policy witnesses describe how risks are assessed and factored into cost decisions on an enterprise-wide basis. See Exhibits SDG&E-02 (Day) and SDG&E-03 (Schneider/Geier).

Risk evaluation is a critical component of the TIMP and DIMP framework. In this section of my testimony, I describe how risk assessment and management is embedded within the TIMP and DIMP through several processes and how it is the key driver in the scheduling and implementation of assessments and mitigation activities. In TIMP, transmission pipelines are evaluated to identify and address risks in HCAs, as well as non-HCAs. DIMP is focused on evaluating and reducing distribution pipeline integrity risks above and beyond general maintenance requirements. Risk models are used to calculate risk scores, which drive the prioritization of mitigation activities.

1. Risk Assessment

The risks identified through the TIMP and DIMP include risks to public and employee safety, system reliability and physical security. Identified threats that can lead to a pipeline failure have the potential to impact employee and public safety by causing bodily injury, property damage, or disruption of service to customers. The loss of pipeline or facility equipment could impact system reliability by reducing system capacity, inhibiting the ability to efficiently move gas through system and/or diminishing deliverability of gas to customers. This could have a particularly significant impact on customers that provide key health and safety services, such as hospitals and electric generators.

Operating a gas system located in an area that is exposed to earthquakes and severe weather drives us to also consider the effects of natural disasters and the risks they pose. In the

TIMP risk evaluation, we look at the potential for loss of pipelines or facilities due to severe weather, earthquakes and land movements.

The analysis of these risks includes the evaluation of the probability of the risks occurring and the potential consequences if a risk is realized. This allows us to comprehensively evaluate our risk exposure in operating our gas pipelines.

2. Risk Mitigation and Alternatives Evaluation

An essential component of an effective risk management program is the development of mitigation plans once risks are identified and analyzed. In the TIMP and DIMP, we evaluate potential alternatives for mitigating an identified risk. The condition of the pipeline, operating factors and location are elements considered in evaluating the risk mitigation alternatives. Within each risk mitigation activity conducted under the TIMP, several alternatives are considered as follows:

Assessments: In evaluating and managing transmission pipeline risks, we consider various assessment options such as External Corrosion Direct Assessment, Internal Corrosion Direct Assessment, In-Line Inspection, Pressure Testing and other assessment methodologies, as further described in later sections of this testimony.

Remediation: Remediation plans are developed based on data collected from the assessment and the options considered for remediating anomalies found in the pipeline.

Additional Preventative and Mitigative Measures: The analysis of data retrieved from the completion of excavations and assessments help determine reassessment cycles and the need for further preventative or mitigative actions on the pipelines. Options considered for further mitigation include the addition of rectifiers, monitoring probes and additional surveys along the pipelines. These preventative measures may eliminate the need for future replacements.

Under the DIMP, causes of distribution pipeline failure fall into different categories and based on that categorization, risk mitigation alternatives are evaluated and considered for each identified cause. Programs to address certain failure mechanisms, such as vehicular damage associated with above-ground facilities, have been established for risk mitigation. Alternatives considered in the vehicular damage program include:

- Barrier construction
- Installation of an Excess Flow Valve
- Relocation of the facility

3. Risk Mitigation Activities Selected

Within TIMP, acceptable assessment methods include External Corrosion Direct Assessment, Internal Corrosion Direct Assessment, In-Line Inspection (ILI) and Pressure Testing. An ILI assessment provides an additional level of information that cannot be obtained through other assessment methods. Although the cost of retrofitting a pipeline to allow for ILI may be higher than other alternative assessment methods, the information obtained through an ILI about the condition of the pipeline is extensive and can aid in analyzing time-dependent threats, such as external corrosion and internal corrosion. Therefore, where ILI is one of the methods capable of assessing an identified threat, it is SDG&E's preferred assessment method. Due to SDG&E's proactive safety enhancing investments over the years, approximately 55% of transmission pipelines operated by SDG&E in HCAs can be inspected using ILI. With the additional information obtained from ILIs, a more complete picture of the overall condition of SDG&E's transmission pipelines can be captured. This allows for an overall risk reduction in both HCA and non-HCA pipe segments.

During the remediation of a pipeline anomaly, SDG&E considers cost in selecting among various remediation options. For example, where appropriate, SDG&E will use a welded sleeve over a cylindrical replacement of a pipe segment to remediate an identified threat. The installation of the sleeve provides the same level of safety as a replacement, but at a lower cost. SDG&E's approach to preventative and mitigative measures seeks to avert the need for pipe replacement in order to achieve the objective or maintaining safe and reliable service at reasonable cost.

4. Integration of Risk Mitigation Actions and Investment Prioritization

The risk assessment that is conducted on transmission and distribution pipelines drives the prioritization of investments to address the most significant risks first. In TIMP, the risk model employed calculates risk scores for the identified threats using a risk analysis application. The TIMP is designed to prioritize investments based on the risk scores where the most pressing risks are addressed first on a programmatic basis. In DIMP, the DREAMS tool is used to prioritize risk mitigation of early-vintage pipeline segments, which provides further prioritization for replacement investments based on a leakage root-cause analysis.

5. Investment Dollars Included in the GRC Request to Support Risk Mitigation

The O&M and capital costs summarized in the tables below support TIMP and DIMP activities. The main cost drivers are the assessments for the TIMP and the Programs and Activities to Assess Risk (PAARs) for the DIMP.

TABLE MTM-2
San Diego Gas & Electric Company
Non-Shared O&M Summary of Costs

TIMP & DIMP			
Shown in Thousands of 2013 Dollars			
Categories of Management	**2013 Adjusted-Recorded**	**TY2016 Estimated**	**Change**
A. TIMP	4,206	5,451	1,245
B. DIMP	3,203	6,033	2,830
Total	**7,409**	**11,484**	**4,075**

Table MTM-3
San Diego Gas & Electric Company
Capital Expenditures Summary of Costs

TIMP & DIMP			
Shown in Thousands of 2013 Dollars			
Categories of Management	**Estimated 2014**	**Estimated 2015**	**Estimated 2016**
A. TIMP	5,180	3,996	3,996
B. DIMP	2,777	2,794	20,219
Total	**7,957**	**6,790**	**24,215**

II. NON-SHARED COSTS

Table MTM-4 summarizes the total non-shared O&M forecasts for the listed cost categories.

TABLE MTM-4
San Diego Gas & Electric Company
Non-Shared O&M Summary of Costs

TIMP & DIMP			
Shown in Thousands of 2013 Dollars			
Categories of Management	**2013 Adjusted-Recorded**	**TY2016 Estimated**	**Change**
A. TIMP	4,206	5,451	1,245
B. DIMP	3,203	6,033	2,830
Total	**7,409**	**11,484**	**4,075**

A. Transmission Integrity Management Plan Activities

1. Description of Costs and Underlying Activities

To comply with 49 CFR 192, Subpart O—Gas Transmission Pipeline Integrity Management, SDG&E is required to continually identify threats to transmission pipelines located in HCAs, determine the risk posed by these threats, schedule and track assessments to address threats within prescribed timelines, collect information about the condition of the pipelines, take actions to minimize applicable threats and integrity concerns to reduce the risk of a pipeline failure and report findings to regulators.

The activities prescribed by Subpart O are primarily implemented and managed by the TIMP team. The team is composed of engineers, project managers, technical advisors, project specialists and other employees with varying degrees of responsibility. The various TIMP activities are categorized into the following seven topics areas of discussion to demonstrate the reasonableness of the labor and non-labor cost associated with the compliance of Subpart O:

- Threat Identification and Risk Assessment;
- Baseline Assessment Plan;
- Assessment;
- Remediation;
- Additional Preventative and Mitigative Measures;
- Geographic Information System (GIS); and

- Auditing and Reporting.

These costs support SDG&E's goals of operating the system safely and with excellence by continually assessing, mitigating and reducing system risk. The costs will be balanced and recorded in a regulatory balancing account, the Transmission Integrity Management Program Balancing Account (TIMPBA), as described in the Regulatory Accounts testimony of witness Norma Jasso, Exhibit SDG&E-35.

Threat Identification and Risk Assessment: An operator is required to perform threat identification and risk assessment of its transmission pipelines per Subpart O. Threat identification and risk assessment are considered the starting point in SDG&E's TIMP implementation process. SDG&E uses a prescriptive approach for threat identification which includes the nine categories of threats described in ASME B31.8S: External Corrosion; Internal Corrosion; Stress Corrosion Cracking; Manufacturing, Construction; Equipment; Third Party; Incorrect Operations; and Weather Related and Outside Force. All pipelines operated in HCAs are evaluated for each threat category. A risk assessment of the HCA pipelines and identified threats is done through a relative assessment. The relative assessment integrates relevant threats, industry data and Company experience to prioritize HCA pipeline segments for baseline and continual reassessment.

Assessment Plan: Once the pipeline threats are identified, a risk assessment is completed and the HCA pipelines are prioritized, an Assessment Plan is created and maintained to manage the scheduling and due dates for all assessments. In some instances, multiple assessment methods for the same pipeline section may be necessary, depending on the threats that need to be evaluated. The allowable methods prescribed by the DOT Pipeline and Hazardous Material Safety Administration (PHMSA) that may be used for inspecting (assessing) an HCA pipeline are: In-Line Inspection; Pressure Testing, Direct Assessment and Other Technology.[3]

Assessments: The assessment methods primarily employed by SDG&E are In-Line Inspection, Pressure Testing, External Corrosion Direct Assessment and Internal Corrosion Direct Assessment. The assessment process includes reviewing and gathering historical data, collecting pipelines samples (in some instances), completing the assessment and evaluating the results of the assessment.

[3] 49 CFR 192.921.

In-Line Inspection: The in-line inspection assessment method utilizes specialized inspection tools that travel inside the pipeline. SDG&E plans to complete three ILI assessments in 2016, for a total of approximately 37.5 miles of HCA and non-HCA pipeline. ILI tools are often referred to as "smart pigs." Smart pigs come in a variety of types and sizes with different measurement capabilities that assist in collecting information about the pipeline. This specialized tool requires that the pipeline be configured to accommodate its passage. As this technology did not exist when many pipelines were constructed, the use of this assessment method often requires pipeline segments to be modified or retrofitted to allow passage of the tool. Retrofits include the replacement of valves, removal of certain bends and any other obstruction 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 smart pig, a series of pigs are passed through the pipeline to clean out and collect information about the pipeline.

In a conventional ILI assessment, the tool is inserted into the pipeline and pushed by a differential of gas pressure on either side of the tool. In instances where there is insufficient pressure to push the tool through the pipeline, the tool can be tethered and pulled through the pipeline. This process is often referred to as "unconventional ILI." The cost and effort to setup an unconventional ILI is more than a typical ILI assessment, as the pipeline may need to be taken out of service and access points need to be close together to accommodate the length of the tether.

Pressure test: Pressure testing is a method that uses a hydraulic approach by filling the pipeline, usually with water, at a pressure greater than the maximum allowable operating pressure of the pipeline for fixed period of time. In certain circumstances, the pipeline may be temporarily removed from service post-construction, pressure-tested, and then returned to service. If a leak occurs during the pressure test, the leak is investigated and remediated prior to continuing or completing a pressure test.

External Corrosion Direct Assessment (ECDA): ECDA is a process that proactively seeks to identify external corrosion defects before they grow to a size that can affect the integrity of the inspected pipeline. SDG&E plans to complete one assessment of two miles of HCA pipeline using ECDA in 2016. Additional detail regarding this activity may be found in my workpapers, Exhibit SDG&E-07-WP. The ECDA process requires integration of operating data 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. ECDA is labor-intensive and, depending on the location of the excavations, the cost can be significant.

Internal Corrosion Direct Assessment (ICDA): ICDA is a process that assesses and predicts areas where internal corrosion is likely to occur. The process incorporates operating data, elevation profile, flow modeling and inclination angle analysis. This information is used to identify potential low spots where liquids are most likely to accumulate and where internal corrosion may have occurred or may be occurring. Once these areas are identified, excavation of sites validate if internal corrosion exists at the selected sites. ICDA is labor-intensive and, depending on the results of the detailed examination, a significant increase in the number of excavations may be required.

Remediation: The remediation of a pipeline can occur at different stages depending on the assessment method selected. For an assessment completed using ILI, the remediation occurs after the assessment is complete and the results of the ILI are provided by the vendor. The vendor report provides an overall assessment of the pipeline and possible areas of concerns. The identified areas of concern can vary greatly from assessment to assessment. These areas may include locations where corrosion has occurred or is occurring, as evidenced by indications collected during the inspection. Once these areas are identified, sites are prioritized for pipe surface evaluations to validate or re-rank the identified areas. Remediation through repair or reconditioning of the pipeline coating is completed at the time of excavation. A repair can include a pipe replacement, welded steel sleeve repair or grinding of the defect. ILI anomalies are classified as immediate, scheduled, or monitored, with immediate anomalies being the most severe and requiring immediate action in terms of repair and pressure reductions, as prescribed under 49 CFR 192.933 and ASME B31.8, based on data analysis and evaluation.

An ECDA assessment is complete once the areas identified using the various survey results are excavated and reviewed. In the case of ECDA, the remediation through repair or reconditioning of the pipeline occurs in parallel to the assessment being completed. A repair can include a pipe replacement, welded steel sleeve repair or grinding of the defect.

For a pressure test assessment, the remediation of the pipeline occurs as a result of a failed pressure test and the remediation would need to be completed to continue testing the pipeline. A pressure test cannot be successfully conducted until all remediation work is completed.

Additional Preventative and Mitigative Measures: After the excavations are performed and the assessment is complete, the data is analyzed to determine the need for preventative and mitigative measures and to establish the reassessment interval for the pipeline, up to a maximum of seven years. Preventative and mitigative measures are developed based on the requirements of 49 CFR 192.935(a). When appropriate, the consideration of additional measures for pipeline segments with similar operating conditions will be undertaken for both HCA and non-HCA pipelines.[4] For 2016, preventative and mitigative measures include the addition of rectifiers, monitoring probes, and additional surveys along the pipelines.

Geographic Information System: A GIS is a computer system designed to capture, store, manipulate, analyze, manage and present all types of geographical data. GIS can be thought of as a system that provides spatial data entry, management, retrieval, analysis and visualization functions. SoCalGas currently manages two GIS for both SoCalGas and SDG&E, one for medium pressure pipelines operating at 60 psig or less, and one for high pressure pipelines operating at greater than 60 psig. In my testimony, the GIS used to manage high pressure pipelines is referred to as the High Pressure Pipeline Database (HPPD) and the GIS used to manage medium pressure pipelines is referred to as the Enterprise GIS or E-GIS. The HPPD is at the core of all TIMP activities and houses and maintains the data collected for transmission pipelines during the pre-assessment process, during the various assessments, and remediation efforts completed as part of TIMP. Maintenance of the HPPD is required to continuously reflect changes in the pipeline system based on new construction, replacements, abandonments or re-conditioning of pipelines for not only TIMP-related projects, but also for all companywide projects in order to analyze the entire transmission pipeline system holistically. Various tool sets (applications) used within the HPPD allow for the analysis and determination of HCAs, relative risk evaluation of the transmission system and the creation of Assessment Plans.

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4 *See* 49 CFR 192.917(e)(5) *Corrosion.* ("If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in 192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under Part 192 for testing and repair.")

Auditing and Reporting: The California Public Utilities Commission (CPUC) conducts audits of the TIMP and submits requests for data on a regular basis, which must be addressed in a timely manner. On an annual basis, relevant integrity data regarding overall program measures and threat-specific measures is gathered and reported per 49 CFR 192.945 and ASME/ANSI B31.8S-2004, section 9.4. The following overall program measures are reported on an annual basis in Form PHMSA F 7100.2-1 Annual Report for Calendar Year (reporting year) Natural and Other Gas Transmission and Gathering Pipeline Systems:

- Number of total system miles existing as of the end of the reporting period;
- Number of total miles inspected during the reporting period;
- Number of total HCA miles covered by the Integrity Management Program, as of the end of the reporting period;
- Number of HCA miles inspected via Integrity Management Program assessments during the reporting period;
- Number of "Immediate" repair conditions completed in HCAs as a result of Integrity Management Program inspections during the reporting period;
- Number of "One-year" repair conditions completed in HCAs as a result of Integrity Management Program inspections during the reporting period;
- Number of "Monitored" repair conditions completed in HCAs as a result of Integrity Management Program inspections during the reporting period;
- Number of "Other Scheduled" repair conditions completed in HCAs as a result of Integrity Management Program inspections during the reporting period;
- Number of anomalies identified, excavated and repaired (HCA and non-HCA) as a result of Integrity Management Program inspections during the reporting period; and
- Number of leaks (HCA and non-HCA) and failures (HCA), classified by cause, during the reporting period.

2. Forecast Method

The forecast method developed for this cost category is zero-based. Reliance on a five-year average to develop cost forecasts would not be appropriate, because the historic average does not reflect recent upward pressures and expectations created by recent pipeline failure incidents in the industry, such as those that occurred in Sissonville, West Virginia (NTSB No. PAR-14-01), San Bruno, California (NTSB No. PAR-11-01) and Palm City, Florida (NTSB No.

PAB-13-01).[5] Upward pressures on the TIMP include the prudence of expanding inspections beyond HCAs, increasing the ability to assess pipelines using ILI, enhancing data collection practices and improving data traceability.

A zero-based method is most appropriate because the costs directly correlate to the number of assessments conducted each year, which varies from year to year. Results from assessments coupled with the regulatory requirements for reassessment intervals establish the reassessment plan (timeline) for pipelines, which cannot be extended.[6] The forecast methodology is fundamentally rooted on average unit cost, as described in greater detail in my workpapers, Exhibit SDG&E-07-WP.

3. Cost Drivers

The cost drivers behind this forecast include both labor and non-labor components. The cost drivers for labor are the Program Management teams required to provide direction, guidance, and oversight to meet compliance and program requirements, as well as supplemental contracted non-labor for process improvement, process guidance and peak activity level support. The cost drivers are based on the number of assessments (ILI, Direct Assessment or Pressure Test), repairs and mitigation activities required to achieve compliance. Anticipated cost drivers that cannot currently be defined with specificity relate to PHMSA's issuance of a draft process entitled "Integrity Verification Process," on June 28, 2012, which addresses many of the recommendations and mandates outlined by the National Transportation Safety Board and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, signed by President Obama on January 3, 2012. The Integrity Verification Process may impact SDG&E's TIMP and DIMP activities, depending on the PHMSA's final requirements.

B. Distribution Integrity Management Program

1. Description of Costs and Underlying Activities

These activities are required to comply with 49 CFR Part 192, Subpart P—Gas Distribution Pipeline Integrity Management. PHMSA established DIMP requirements to enhance pipeline safety by having operators identify and reduce pipeline integrity risks for distribution pipelines, as required under the Pipeline Integrity, Protection, Enforcement and

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[5] NTSB publishes its reports at http://www.ntsb.gov/investigations/reports_pipeline.html.

[6] *See* 49 CFR 192.939 (establishing express requirements for determining the reassessment interval for covered pipelines, and stipulating that "the maximum reassessment interval by an allowable reassessment method is seven years.")

Safety Act of 2006.[7] This cost will be balanced and recorded in the Post-2011 Distribution Integrity Management Program Balancing Account (DIMPBA), as described in the Regulatory Accounts testimony of Norma Jasso, Exhibit SDG&E-35. These activities are primarily implemented and managed by the DIMP team. The team is composed of engineers, project managers, technical advisors, project specialists and other employees with varying degrees of responsibility. This cost supports the Company's goals of operating the system safely and with excellence by continually assessing, mitigating and reducing overall system risk. The following topics and activities are discussed in additional detail below to demonstrate the reasonableness of the labor and non-labor cost forecasts:

- System Knowledge;
- Threat Identification and Risk Analysis;
- Programs and Activities to Address Risk;
- Geographic Information System; and
- Compliance, Auditing and Reporting.

System Knowledge: System knowledge is developed from reasonably available information and is attained through an understanding of system attributes such as design, materials and construction methods, pipeline condition, past and present operations and maintenance, local environmental factors, and failure data (*e.g.*, leaks). Data collection for SDG&E's 14,052 miles of distribution main and services is an extensive process that continues to improve over time.

Threat Identification and Risk Analysis: Threat is defined as a combination of the "Cause" and the "Facility." The major categories of "Causes" are the eight cause categories listed in 49 CFR 192.1015(a)(2): Excavation Damage; Other Outside Force Damage; Corrosion; Material or Welds; Equipment Failure; Natural Force Damage; Incorrect Operations; and Other. The top level facilities are defined as main, service or above-ground facilities. A risk assessment

[7] *See* PHMSA DIMP FAQ B.1.1: Why did PHMSA mandate integrity management requirements for distribution pipeline systems? ("The Pipeline Integrity, Protection, Enforcement, and Safety Act of 2006 (PIPES) mandated that PHMSA prescribe minimum standards for integrity management programs for distribution pipelines. The law provided for PHMSA to require operators of distribution pipelines to continually identify and assess risks on their distribution lines, to remediate conditions that present a potential threat to pipeline integrity, and to monitor program effectiveness. . . . Instead of imposing additional prescriptive requirements for integrity management, PHMSA concluded that a requirement for operator-specific programs to manage pipeline system integrity would be more effective.")

of the distribution system is done through a relative assessment. The relative assessment integrates several data sets, and considers industry data and Company experience to prioritize programs and activities to address risk.

Programs and Activities to Address Risk: PAARs are implemented through different avenues, depending on the threat being addressed. A holistic view of the entire pipeline distribution system is used when determining a PAAR and its related funding level. In alignment with PHMSA's intent and recognition that a PAAR needs to be operator-specific, SDG&E develops PAARs that are specific to the SDG&E system.[8]

Activities can vary from simple changes (such as changing a drop down selection in a data acquisition application for the improvement of the data being collected) to entire programs and funding through rate case filings (such as the sewer lateral inspection program). As noted above, PHMSA's stated purpose for DIMP is to enhance pipeline safety by having operators identify and reduce pipeline integrity risks specifically for distribution pipelines.[9] Since implementing DIMP, SDG&E has created several PAARs to help achieve that objective and new PAARs will continue to emerge. In 2013, SDG&E successfully completed a sewer lateral inspection program and an evaluation of distribution anodeless risers. SDG&E's rationale for augmenting ongoing operations and maintenance activities is based on PHMSA's requirement that operators go beyond their routine work.[10]

The DREAMS PAAR prioritizes certain early-vintage steel (pre-1960) and plastic (pre-1986), including Aldyl-A, for replacement. With regard to plastic, PHMSA Advisory Bulletin ADB-07-01 states that "the number and similarity of plastic pipe accident and non-accident

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[8] *See* PHMSA DIMP FAQ B.1.1: Why did PHMSA mandate integrity management requirements for distribution pipeline systems? (".....Instead of imposing additional prescriptive requirements for integrity management, PHMSA concluded that a requirement for operator-specific programs to manage pipeline system integrity would be more effective.")

[9] *See* PHMSA DIMP FAQ B.1.1: Why did PHMSA mandate integrity management requirements to distribution pipeline system? ("PHMSA's regulation in part 192 have contributed to producing an admirable safety record. Nevertheless, incidents continue to occur, some of which involve significant consequences, including death and injury. It is not possible to significantly reduce high consequence pipeline incidents without reducing the likelihood of their occurrence on distribution pipelines….")

[10] PHMSA DIMP FAQ C.3.4: What is the relationship between an operations & maintenance manual and a DIMP plan? ("An O&M manual contains written procedures describing how operators conduct operations and maintenance activities on their system in accordance with Federal and State pipeline safety regulations. The activities address various threats to a pipeline's integrity. A DIMP plan is a written integrity management plan which describes the analysis of the operator's system, provides a relative risk analysis based on threats to the system, <u>and prescribes additional or accelerated actions as needed to address risks identified in the plan</u>…") (emphasis added).

failures indicate past standards used to rate the long-term strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking for much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s." SDG&E will continue using risk evaluation to accelerate replacements on a targeted basis. The risk evaluation considers the leakage history, cathodic protection (for steel), vintage of the pipe and the location using E-GIS. Each year, SDG&E targets 17 miles of replacement above and beyond routine replacements, in accordance with DIMP regulations. SDG&E forecasts the capital component under Budget Code 9546 – Distribution Integrity Management Program. This expenditure is explained in the capital portion of my testimony in section III.B below.

The Gas Infrastructure Protection Program (GIPP) PAAR addresses potential vehicular damage associated with above ground distribution facilities. To address vehicular damage to Company facilities, SDG&E has identified, evaluated and implemented a damage prevention solution that includes a collection of mitigation measures to address this threat. The collection of mitigation measures includes: construction of barriers (bollards or block wall), relocation of the facility, or installation of an Excess Flow Valve. This program is responsive to PHMSA guidance indicating that operators should address low frequency, but potentially high consequence, events through the DIMP.[11] SDG&E forecasts the capital component under Budget Code 9546 – Distribution Integrity Management Program. This expenditure is explained in the capital portion of my testimony in section III.B below.

<u>Geographic Information System</u>: The E-GIS, as mentioned earlier, houses and maintains pipeline information on all distribution pipelines operating at or below 60 psig and is at the core of all DIMP activities. The HPPD also houses information on high pressure distribution pipelines operating above 60 psig. Information gathered during the pre-assessment process and field activities is integrated into the HPPD and E-GIS. The maintenance of these databases through editing and quality control is required to continually reflect changes in the pipeline system based on new construction, replacements and abandonments for not only DIMP-related projects, but also for all Company-wide projects, in order to analyze the entire distribution pipeline system and determine programs and activities needed to address risk. Various tool sets

[11] *See* PHMSA Gas Distribution Pipeline Integrity Enforcement Guidance: 49 CFR Part 192 – Subpart P, available at: http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_61354CFDB0D1A9033931723B931E3EEF668A0700/filename/DIMP_Enforcement_Guidance(1_29_2014).pdf).

(applications) used within the HPPD and E-GIS allow for analysis and a relative risk evaluation of the distribution system.

Compliance, Auditing and Reporting: On an annual basis, relevant integrity data regarding overall program measures is gathered and reported per 49 CFR 192.1007 and 192.1009. The following overall program measures are reported on an annual basis in Form PHMSA F 7100.1-1 Annual Report for Calendar Year (reporting year) Gas Distribution System:

- Excavation Damages;
- Leaks Repaired;
- Number of Hazardous Leaks Repaired; and
- Mechanical Fitting Failures.

2. Forecast Method

The forecast method developed for this cost category is zero-based. SDG&E implemented DIMP on August 2, 2011, as mandated by the regulations. Since the DIMP has only been officially in place since 2011, reliance on either a five or three-year average for cost forecasting would not be appropriate. The forecast methodology is fundamentally rooted on average unit cost, and described in greater detail in my workpapers, Exhibit SCG-07-CWP.

In recent years, incidents in the gas industry, such as the failure that occurred in Saint Paul, Minnesota on February 1, 2010, when a contractor cut a natural gas line while attempting to unclog a sewer pipe, causing an explosion and fire, and explosion that occurred in Cupertino, California on August 31, 2012, when a plastic pipe (Aldyl-A) failed, damaging a condominium, have applied an upward pressure for Distribution operators to analyze system risk and implement programs and activities to address risk on an accelerated scale not typically experienced by the industry before.

3. Cost Drivers

The cost drivers behind this forecast include both labor and non-labor components. The cost drivers for labor are the Program Management teams required to provide direction, guidance, and oversight to meet compliance and program requirements, as well as the supplemental contracted non-labor for process improvement, process guidance and peak activity level support. The cost drivers with regard to the E-GIS are based on the hours required to maintain the E-GIS, the number of data model changes required to support regulation requirements and the integration of various databases. The cost drivers with regard to the

PAARs discussed above are based on time required to gather necessary information, integrate and analyze that information, analyze potential mitigation activities, and implement the selected mitigation approach.

III. CAPITAL

Table MTM-5 summarizes the total capital forecasts for TIMP and DIMP for 2014, 2015, and 2016.

TABLE MTM-5
San Diego Gas & Electric Company
Capital Expenditures Summary of Costs

TIMP & DIMP			
Shown in Thousands of 2013 Dollars			
Categories of Management	**Estimated 2014**	**Estimated 2015**	**Estimated 2016**
A. TIMP	5,180	3,996	3,996
B. DIMP	2,777	2,794	20,219
Total	**7,957**	**6,790**	**24,215**

A. TIMP (Budget Code 3468)

1. Description

Budget Code 3468 captures all TIMP-related capital costs. The forecast for this budget code for 2014, 2015 and 2016 is $5,180, $3,996 and $3,996, respectively.

As discussed previously, under TIMP regulations, 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. Through the TIMP, SDG&E continually evaluates the pipeline system and proactively takes action through inspections, replacements and other remediation activities to improve the safety and reliability of the system. These forecasted capital expenditures support the Company's core goals of providing safe and reliable service at reasonable cost.

Recent incidents in the gas industry, examples of which are discussed above, has applied an upward pressure on the TIMP to expand inspections beyond HCAs, increase the ability to assess pipelines using in-line inspection and improve data collection and traceability.

SDG&E has focused on the ability of assessing pipelines using in-line inspection with 55% of the transmission pipelines (129 miles) able to accommodate in-line inspection as of the end of year 2013. As noted previously, ILI pipeline assessments are performed using an internal electronic device that internally traverses the pipeline to collect information that is used to assess the pipeline. Some 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. Although the cost of retrofitting a pipeline to allow for in-line inspection may be higher than other alternative assessment methods, the information obtained through an in-line inspection about the condition of the pipeline is extensive and can aid in analyzing time dependent threats such as external corrosion and internal corrosions. When possible, multiple pipelines may be combined into a single run and, conversely, a single pipeline may require multiple launcher and receiver points.

When it is more economical than retrofitting a pipeline to conduct an ILI assessment to comply with TIMP regulations, a pipeline may be altered or replaced, if the construction can be implemented within the mandated TIMP assessment schedule.

These forecasted capital expenditures support the Company's core goals of providing safe and reliable service at reasonable cost. Through the TIMP, SDG&E continually evaluates the transmission pipeline system and proactively takes action through inspections, replacements and other remediation activities to improve the safety and reliability of the system.

Actual TIMP capital costs will be balanced and recorded in the TIMPBA, as described in the Regulatory Accounts testimony of Norma Jasso, Exhibit SDG&E-35. Specific details regarding Budget Code 3468 may be found in my capital workpapers, Exhibit SDG&E-07-CWP.

2. Forecast Method

The forecast method developed for this cost category is zero-based. A zero-based method is most appropriate because the costs directly correlate to the number of assessments being conducted the year, which varies from year to year. Results from assessments, coupled with the regulatory requirements for reassessment intervals, establish the reassessment plan (timeline) for pipelines, which cannot be extended.[12]

Construction cost estimates are based on experience gained working on projects of similar scope in similar settings. The forecast methodology is fundamentally rooted on average unit cost, as described in greater detail in my workpapers, Exhibit SDG&E-07-WP.

3. Cost Drivers

The underlying cost drivers for Budget Code 3468 relate to the number of assessments (ILI, Direct Assessment and Pressure Test), repairs and mitigation activities required. Documentation of these cost drivers is included as a supplemental capital workpaper in Exhibit SDG&E-07-CWP.

B. DIMP (Budget Code 9546)

1. Description

Budget Code 9546 captures the capital costs related to DIMP that may be incurred as a result of PAAR activities. The forecast for this budget code for 2014, 2015 and 2016 is $2,777, $2,794 and $20,219, respectively.

As discussed previously, 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 requirement to replace identified system components at an accelerated rate. The DREAMS-driven main and service replacements represent activity that is incremental to routine replacement work and required to maintain system integrity, along with compliance with new DIMP regulatory requirements. The GIPP spending focuses on mitigative activities associated with the threat of vehicular damage.

Specific details regarding Budget Code 9546 may be found in my capital workpapers, Exhibit SDG&E-07-CWP. Actual DIMP-related capital costs will be balanced and recorded in the Post-2011 DIMPBA, as described in the Regulatory Accounts testimony of Norma Jasso, Exhibit SDG&E-35.

Specific details regarding Budget Code 9546 may be found in my capital workpapers, Exhibit SDG&E-07-CWP.

[12] *See* 49 CFR 192.939 (establishing express requirements for determining the reassessment interval for covered pipelines and stipulating that "the maximum reassessment interval by an allowable reassessment method is seven years.")

2. Forecast Method

The forecast method developed for this cost category is zero-based. SDG&E implemented DIMP on August 2, 2011, as required by applicable regulations. Since the DIMP has only been officially in place since 2011, reliance on either a five or three-year average would not be appropriate. Recent incidents in the gas industry, examples of which are provided above, have applied an upward pressure for distribution operators to analyze the risks to their distribution systems and implement programs and activities to address risk on an accelerated scale not typically experienced by the industry before.

3. Cost Drivers

The cost drivers behind this forecast include both a labor and non-labor component. The cost drivers for the labor component include the Program Management Teams required to provide direction, guidance, oversight to meet compliance and program requirements as well as the supplemental contracting non-labor for process improvement, process guidance and peak activity level support. The underlying cost drivers for the non-labor component relate to the miles of main and number of services targeted for replacement. Documentation of these cost drivers is provided as a supplemental capital workpaper in Exhibit SDG&E-07-CWP.

IV. CONCLUSION

The funding requested for TIMP and DIMP is reasonable to support the activities outlined and intended to meet the requirements set forth in 49 CFR Part 192, Subpart O - Gas Transmission Pipeline Integrity Management and 49 CFR Part 192, Subpart P – Gas Distribution Integrity Management. SDG&E's TIMP and DIMP are designed to continually identify and assess risks, remediate conditions that present a potential threat to pipeline integrity, monitor program effectiveness and maintain safe and reliable service to customers at reasonable cost. This concludes my prepared direct testimony.

V. WITNESS QUALIFICATIONS

My name is Maria T. Martinez. My business address is 555 W. Fifth Street, Los Angeles, California, 90013. I am employed by SoCalGas as the Pipeline Integrity Director for SoCalGas and SDG&E. In this position, I am responsible for providing centralized program support for Pipeline Integrity for both Transmission and Distribution. To accomplish this responsibility, I manage an organization of 100+ employees with varying degrees of technical expertise.

In addition, I possess a broad background in engineering and natural gas pipeline operations with over ten years of experience with SoCalGas and SDG&E. I have held numerous positions with increasing responsibilities within Pipeline Integrity and Gas Distribution Operations. I have been responsible for various areas related to Pipeline Integrity such as Data Collection, Risk and Threat, Assessment Planning and Annual Reporting. I have held my current position as Director of Pipeline Integrity since January 2014.

I hold a Bachelor of Science degree in Mechanical Engineering from California State Polytechnic University, Pomona. I hold a California Professional Engineering License in mechanical engineering from the state of California.

I have not previously testified before the Commission.

APPENDIX A - GLOSSARY OF ACRONYMS

DIMP	Distribution Integrity Management Program
DIMPBA	DIMP Balancing Account
DOT	U.S. Department of Transportation
DREAMS	Distribution Risk Evaluation and Monitoring System
ECDA	External Corrosion Direct Assessment
GIPP	Gas Infrastructure Protection Program
GIS	Geographic Information System
HCA	High Consequence Area
ICDA	Internal Corrosion Direct Assessment
ILI	In-Line Inspection
PAAR	Program and Activities to Address Risk
PHMSA	Pipeline and Hazardous Material Safety Administration
TIMP	Transmission Integrity Management Program
TIMPBA	TIMP Balancing Account