Application of San Diego Gas & Electric Company (U902M) for authority to update its gas and electric revenue requirement and base rates effective on January 1, 2012.	A.10-12-005
Application of Southern California Gas Company for authority to update its gas revenue requirement and base rates effective on January 1, 2012. (U904G)	A.10-12-006

Exhibit No.: (SCG-05-CWP-R)

REVISED CAPITAL WORKPAPERS TO
PREPARED DIRECT TESTIMONY
OF RAYMOND K. STANFORD
ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

JULY 2011

The Gas Company

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 36-7-06 PI Retrofit	00276.01
WITNESS Raymond Stanford	**IN SERVICE DATE** 04/30/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				62			62
DIRECT NONLABOR			1	569			570
TOTAL DIRECT CAPITAL			1	631			632
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL			1	631			632
FTE	.0	.0	.0	.7	.0	.0	.7

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 36-7-06.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 36-7-06 PI Retrofit	00276.01
WITNESS	**IN SERVICE DATE**
Raymond Stanford	04/30/2011

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:

1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 36-7-06 PI Retrofit	00276.01
WITNESS	**IN SERVICE DATE**
Raymond Stanford	04/30/2011

the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the "fixed" component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The "variable" component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

Excavation Component:

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 36-7-06 PI Retrofit	00276.01
WITNESS	**IN SERVICE DATE**
Raymond Stanford	04/30/2011

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

Based upon the methodology described above, the projected costs for this project by component are:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	.36	3.28	3.64
Cost of launch/receiver	62.08	565.96	628.03
Capital Sum	**62.44**	**569.23**	**631.67**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 04/30/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the internal inspection device traversing internally through the pipeline. This work is commonly referred to as "retrofitting" the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 36-7-06 PI Retrofit	00276.01
WITNESS	**IN SERVICE DATE**
Raymond Stanford	04/30/2011

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 36-7-PI Retrofit	00276.02
WITNESS	**IN SERVICE DATE**
Raymond Stanford	08/31/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				63			63
DIRECT NONLABOR			2	574			576
TOTAL DIRECT CAPITAL			2	637			639
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL			2	637			639
FTE	.0	.0	.0	.7	.0	.0	.7

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 36-7-04. 0

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 36-7-PI Retrofit	00276.02
WITNESS	IN SERVICE DATE
Raymond Stanford	08/31/2011

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:
1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 36-7-PI Retrofit	00276.02
WITNESS	**IN SERVICE DATE**
Raymond Stanford	08/31/2011

the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the “fixed” component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The “variable” component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

Excavation Component:

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 36-7-PI Retrofit	00276.02
WITNESS	**IN SERVICE DATE**
Raymond Stanford	08/31/2011

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

Based upon the methodology described above, the projected costs for this project by component are:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	1.08	9.83	10.91
Cost of launch/receiver	62.08	565.96	628.03
Capital Sum	**63.15**	**575.79**	**638.94**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 08/31/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the internal inspection device traversing internally through the pipeline. This work is commonly referred to as "retrofitting" the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 36-7-PI Retrofit	00276.02
WITNESS	**IN SERVICE DATE**
Raymond Stanford	08/31/2011

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 41-6903	00276.03
WITNESS Raymond Stanford	**IN SERVICE DATE** Blanket

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			2	68			70
DIRECT NONLABOR			14	621			635
TOTAL DIRECT CAPITAL			15	689			704
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL			15	689			704
FTE	.0	.0	.0	.7	.0	.0	.8

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 41-6903. 0

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 41-6903	00276.03
WITNESS	**IN SERVICE DATE**
Raymond Stanford	Blanket

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:

1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with

PROJECT TITLE Gas Transmission Pipeline Replacement/ Externally Driven Line 41-6903	BUDGET NO. 00276.03
WITNESS Raymond Stanford	IN SERVICE DATE Blanket

the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the “fixed” component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The “variable” component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

Excavation Component:

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 41-6903	00276.03
WITNESS	**IN SERVICE DATE**
Raymond Stanford	Blanket

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

Based upon the methodology described above, the projected costs for this project by component are:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	7.55	68.81	76.36
Cost of launch/receiver	62.08	565.96	628.03
Capital Sum	**69.62**	**634.77**	**704.39**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 12/31/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the internal inspection device traversing internally through the pipeline. This work is commonly referred to as "retrofitting" the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 41-6903	00276.03
WITNESS	**IN SERVICE DATE**
Raymond Stanford	Blanket

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 38-573 – Pipeline Integrity	00276.04
WITNESS	**IN SERVICE DATE**
Raymond Stanford	Blanket

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			3	76			79
DIRECT NONLABOR			31	692			723
TOTAL DIRECT CAPITAL			35	768			803
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL			35	768			803
FTE	.0	.0	.0	.8	.0	.0	.9

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 38-573. 0

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 38-573 – Pipeline Integrity	00276.04
WITNESS	**IN SERVICE DATE**
Raymond Stanford	Blanket

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:

1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 38-573 – Pipeline Integrity	00276.04
WITNESS	**IN SERVICE DATE**
Raymond Stanford	Blanket

the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the “fixed” component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The “variable” component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

Excavation Component:

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 38-573 – Pipeline Integrity	00276.04
WITNESS	IN SERVICE DATE
Raymond Stanford	Blanket

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

Based upon the methodology described above, the projected costs for this project by component are:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	17.25	157.28	174.53
Cost of launch/receiver	62.08	565.96	628.03
Capital Sum	**79.33**	**723.24**	**802.56**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 12/31/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the internal inspection device traversing internally through the pipeline. This work is commonly referred to as "retrofitting" the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

CAPITAL PROJECT WORKPAGER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 38-573 – Pipeline Integrity	00276.04
WITNESS	**IN SERVICE DATE**
Raymond Stanford	Blanket

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 39-801	00312.05
WITNESS Raymond Stanford	**IN SERVICE DATE** 12/31/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			55	282			337
DIRECT NONLABOR			501	2,569			3,069
TOTAL DIRECT CAPITAL			556	2,850			3,406
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL			556	2,850			3,406
FTE	.0	.0	.6	3.1	.0	.0	3.7

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 36-8-01. 0

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 39-801	00312.05
WITNESS	**IN SERVICE DATE**
Raymond Stanford	12/31/2011

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:

1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with

PROJECT TITLE Gas Transmission Pipeline Replacement/ Externally Driven Line 39-801	BUDGET NO. 00312.05
WITNESS Raymond Stanford	IN SERVICE DATE 12/31/2011

the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the “fixed” component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The “variable” component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

Excavation Component:

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 39-801	00312.05
WITNESS	IN SERVICE DATE
Raymond Stanford	12/31/2011

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

Based upon the methodology described above, the projected costs for this project by component are:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	274.57	2,503.36	2,777.93
Cost of launch/receiver	62.08	565.96	628.03
Capital Sum	**336.65**	**3,069.31**	**3,405.96**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 12/31/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the internal inspection device traversing internally through the pipeline. This work is commonly referred to as "retrofitting" the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 39-801	00312.05
WITNESS Raymond Stanford	**IN SERVICE DATE** 12/31/2011

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 38-504	00276.06
WITNESS	**IN SERVICE DATE**
Raymond Stanford	12/31/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR		186	601				787
DIRECT NONLABOR		1,676	5,480				7,156
TOTAL DIRECT CAPITAL		1,863	6,081				7,943
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL		1,863	6,081				7,943
FTE	.0	1.5	6.5	.0	.0	.0	8.

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 38-504. Retrofit and complete ILI assessment and repairs of Line 38-504. This pipeline is 10”, 12", 16" & 20" in diameter, 34.50 miles long, has 11.64

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 38-504	00276.06
WITNESS	**IN SERVICE DATE**
Raymond Stanford	12/31/2010

miles of HCA and runs from Lemoore Junction (ID 1101-N) at Elm Ave and Hanford-Armona Rd to regulator station (I

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:
1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection

PROJECT TITLE Gas Transmission Pipeline Replacement/ Externally Driven Line 38-504	BUDGET NO. 00276.06
WITNESS Raymond Stanford	IN SERVICE DATE 12/31/2010

of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the “fixed” component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The “variable” component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 38-504	00276.06
WITNESS	**IN SERVICE DATE**
Raymond Stanford	12/31/2010

<u>Excavation Component:</u>

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

<u>Distribution of Labor /Non Labor:</u>

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

In some cases, planning work has commenced upon a particular project and site specific cost estimate has been established for the completion of work. For these projects, the cost forecast is based upon the Work Order Authorization for the project, with an added vacation and sick factor added to labor based upon the year work was incurred or is projected to occur. The projected costs were grouped into categories of work as noted in the table below:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	622.62	6,702.33	7,324.95
Cost of launch/receiver	52.58	565.96	618.53
Capital Sum	**675.20**	**7,268.29**	**7,943.48**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 12/31/2010.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 38-504	00276.06
WITNESS	IN SERVICE DATE
Raymond Stanford	12/31/2010

internal inspection device traversing internally through the pipeline. This work is commonly referred to as “retrofitting” the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Multiple Small Replacement Projects in Lieu of ILI	00276.07
WITNESS	**IN SERVICE DATE**
Ray Stanford	03/31/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			113	127	32		272
DIRECT NONLABOR			3,083	3,411	794		7,288
TOTAL DIRECT CAPITAL			3,196	3,538	826		7,560
COLLECTIBLE	(0)	(0)	(0)	(0)	(0)	(0)	(0)
NET CAPITAL			3,196	3,538	826		7,560
FTE			1.2	1.4	0.3		2.9

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

In certain situations due to the pipe condition, location or environment it may be more economical to replace a pipeline with new pipe operating at lower stress which would not require baseline assessment or repeated re-assessment. This is often the case with short pipe segments and cross over piping. In those situations a pipeline may be replaced in lieu of retrofitting for internal inspection, if the construction can be implemented within the DOT mandated assessment schedule. Alternatively for some longer pipelines pressure reducing facilities (regulation station) may be installed to operate the pipeline at lower pressure and stress levels in lieu of repeated inspection per PSIA 2002.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Multiple Small Replacement Projects in Lieu of ILI	00276.07
WITNESS	**IN SERVICE DATE**
Ray Stanford	03/31/2012

Project Description

Type	Line Number	Year
Replacement	32-6520	2010
Replacement	37-6183	2010
Replacement	30-08	2010
Replacement	32-6521	2011
Replacement	35-6524	2010
Replacement	45-3206	2010
Replacement	41-25-A	2011
Replacement	43-30	2010
Replacement	35-6425	2010
Replacement	41-153	2010
Replacement	30-78	2010
Replacement	37-15	2010
Replacement	30-58	2010
Replacement	32-8042	2010
Replacement	41-128	2010
Replacement	36-1006	2010
Replacement	41-111	2010
Regulator Station	36-7-02	2010
Replacement	42-12	2010
Replacement	30-6205	2011
Replacement	41-6557	2011
Regulator Station	41-84-A	2011

Type	Line Number	Year
Replacement	41-53	2011
Replacement	45-8036	2011
Replacement	30-66	2011
Replacement	32-6523	2011
Replacement	30-6799	2011
Replacement	30-68	2011
Replacement	32-8027	2011
Replacement & Regulator Station	32-8043	2011
Replacement	31-50	2011
Replacement	30-6200	2011
Replacement	30-6209	2011
Replacement	30-6543	2011
Regulator Station	35-6405	2011
Regulator Station	35-40	2011
Replacement	36-9-09	2011
Replacement	3004	2011
Regulator Station	38-230	2010
Replacement	32-6522	2010
Regulator Station	37-49	2010
Replacement	38-959	2010
Replacement	38-200	2010

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following types of projects:

1. Small replacement job consisting of less than 200 feet of new pipe.
2. Medium replacement job consisting of 200 to 1,500 feet of new pipe.
3. Medium-Large replacement jobs consisting of 1,500 feet to 15,000 feet of new pipe.
4. Large replacement job consisting of greater than 15,000 feet of new pipe.
5. Installation of pressure reduction/control facilities to reduce pressure and operating stress

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Multiple Small Replacement Projects in Lieu of ILI	00276.07
WITNESS	IN SERVICE DATE
Ray Stanford	03/31/2012

Often the work to complete replacement of a pipeline, in order to comply with PSIA 2002, spans more than one year. Based on experience with previous pipeline replacements, project expenditures are forecast over a two year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Small replacement job	75%	25%		100%
Medium replacement job	75%	25%		100%
Medium/Large replacement job	75%	25%		100%
Large replacement job	75%	25%		100%
Pressure Reduction facility	75%	25%		100%

Replacement Cost Forecast Component:

This activity is forecast using the scheduled number of pipelines identified for replacement and applying one of three cost factors depending on the size of the replacement job. The cost factors were arrived at using historic replacement cost data from 2006 through 2009. This is the period since the PSIA was passed where an increase in the level of this activity has occurred.

The cost factor is calculated based on actual Distribution pipeline replacement costs found both in BC 267 and 276 for jobs completed from 2006 thru 2009. A single cost per construction job was calculated for small projects consisting of replacement of less than 200 foot of pipe. A replacement cost per foot factor was calculated for medium to large jobs based on the total length of pipe installed. An additional mobilization/demobilization cost factor was used for each HCA segment equivalent in cost to a small job. The replacement cost per foot factor was multiplied by the project specific HCA miles to be replaced and the mob/demob cost factor was multiplied by the project specific HCA segments and added together to determine the replacement forecasts for the medium and large replacement projects.

Small Job: Less than 200ft

Total Cost per replacement project:	$56,500	Per job
Labor (13%)	$6,500	Per job
Non-Labor (87%)	$50,000	Per job

Medium –Medium/Large: 200ft-15,000ft

Labor (2%)	2 % of Total	Per job
Non-Labor (200-1500)	$350	Per foot
Non-Labor (1500-15000)	$140	Per foot

Large Job: 15,000ft to 30,000ft

Labor (2%)	2% of total	Per job
Non-Labor (98%)	$55	Per foot

*Overall an additional $50,000 for each covered segment

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Multiple Small Replacement Projects in Lieu of ILI	00276.07
WITNESS	**IN SERVICE DATE**
Ray Stanford	03/31/2012

Small Replacement Project

A single total project cost was used to forecast small replacement projects that involved replacement of less than 200 foot of pipe. This estimate was based on an average cost for similar sized jobs completed in Distribution BC 276 and BC 267 over the past three years from 2006 thru 2009. A cost of $56,500 total per project regardless of length (less than 200foot) was used to forecast planned replacement jobs.

A distribution of $6,500 Company labor and $50,000 non-labor costs was applied for small replacement projects.

Medium to Medium/Large Replacement Projects

A cost per foot factor for medium to medium/large sized replacement projects of greater than 200 foot and less than 15,000 foot was determined using data from previous replacement projects completed in BC 276 and BC 267 from 2006 thru 2009.
For medium replacement projects consisting of from 200 feet to 1,500 feet of HCA , a factor of $350 per foot of pipe was applied to the total HCA length to forecast replacement costs. For projects consisting of from 1,500 feet to 15,000 feet of HCA footage, a factor of $140 per foot of HCA was used to forecast replacement costs.
A distribution of 2% of the total cost was allocated to Company labor and the remainder of cost applied to non-labor costs on all forecast for medium to medium/large sized replacement projects.

Large Replacement Projects

A cost per foot factor for large sized replacement projects was determined using data from previous replacement projects ranging from 15,000 feet to 30,000 feet in length, completed in BC 276 and BC 267 from 2006 thru 2009.
For large replacement projects consisting of greater than 15,000 feet of HCA, a factor of $55 per foot of pipe was applied to the total HCA length to forecast replacement costs
A distribution of 2% of the total costs was allocated to Company labor and the remainder of cost applied to non-labor costs on all forecast for large sized replacement projects.

Pressure Reduction install Regulation Station Project:

To forecast costs related to installation of new pressure regulation stations in order to reduce pipeline pressure and operating stress two fixed cost per job were used based on historic costs to install this type of facility. For A small or Distribution regulation station a cost of $150,000 was used. For special or large Transmission Pressure Limiting station a cost of $300,000 was used.

Schedule
The completed capital portion of the project, referred to as in-service date for this project is: 03/31/2012.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Multiple Small Replacement Projects in Lieu of ILI	00276.07
WITNESS	**IN SERVICE DATE**
Ray Stanford	03/31/2012

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for replacement. A detailed study of the pipeline components is created. A plan is developed to remove/replace all identified sections of the pipeline. Permits are acquired, Materials are ordered and the job is awarded for construction to a contractor. Construction is started and completed depending on size and duration of job.

Year 2: When construction spans more than one year the remaining work is completed and pipeline is placed in service.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply line 38-366 Replace 4,383 feet of 8" Pipe in Lieu of ILI	00276.08
WITNESS Ray Stanford	IN SERVICE DATE 08/31/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				17	6		23
DIRECT NONLABOR				923	308		1,231
TOTAL DIRECT CAPITAL				940	314		1,254
COLLECTIBLE	(0)	(0)	(0)	(0)	(0)	(0)	(0)
NET CAPITAL				940	314		1,254
FTE				0.2	0.1		0.3

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

In certain situations due to the pipe condition, location or environment it may be more economical to replace a pipeline with new pipe operating at lower stress which would not require baseline assessment or repeated re-assessment. This is often the case with short pipe segments and cross over piping. In those situations a pipeline may be replaced in lieu of retrofitting for internal inspection, if the construction can be implemented within the DOT mandated assessment schedule. Alternatively for some longer pipelines pressure reducing facilities (regulation station) may be installed to operate the pipeline at lower pressure and stress levels in lieu of repeated inspection per PSIA 2002.

Project Description

This project will replace 4,383 feet of SL 38-366. This pipeline is 8" in diameter, 7.8 miles long, has 0.83 miles of HCA and runs from JCT. TRANS L-7025 & SL 38-1102-A (ID 1616) @ BRIMHALL & GREELEY RD. TO R/S 5316 (ID 1591) @ WEDDING LN. N/BRIMHALL near Greenacres, California.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital

PROJECT TITLE Gas Distribution Pipeline Replacements / Externally Driven Supply line 38-366 Replace 4,383 feet of 8” Pipe in Lieu of ILI	BUDGET NO. 00276.08
WITNESS Ray Stanford	IN SERVICE DATE 08/31/2012

repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following types of projects:
1. Small replacement job consisting of less than 200 feet of new pipe.
2. Medium replacement job consisting of 200 to 1,500 feet of new pipe.
3. Medium-Large replacement jobs consisting of 1,500 feet to 15,000 feet of new pipe.
4. Large replacement job consisting of greater than 15,000 feet of new pipe.
5. Installation of pressure reduction/control facilities to reduce pressure and operating stress

Often the work to complete replacement of a pipeline, in order to comply with PSIA 2002, spans more than one year. Based on experience with previous pipeline replacements, project expenditures are forecast over a two year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Small replacement job	75%	25%		100%
Medium replacement job	75%	25%		100%
Medium/Large replacement job	75%	25%		100%
Large replacement job	75%	25%		100%
Pressure Reduction facility	75%	25%		100%

Replacement Cost Forecast Component:

This activity is forecast using the scheduled number of pipelines identified for replacement and applying one of three cost factors depending on the size of the replacement job. The cost factors were arrived at using historic replacement cost data from 2006 through 2009. This is the period since the PSIA was passed where an increase in the level of this activity has occurred.

The cost factor is calculated based on actual Distribution pipeline replacement costs found both in BC 267 and 276 for jobs completed from 2006 thru 2009. A single cost per construction job was calculated for small projects consisting of replacement of less than 200 foot of pipe. A replacement cost per foot factor was calculated for medium to large jobs based on the total length of pipe installed. An additional mobilization/demobilization cost factor was used for each HCA segment equivalent in cost to a small job. The replacement cost per foot factor was multiplied by the project specific HCA miles to be replaced and the mob/demob cost factor was multiplied by the project specific HCA segments and added together to determine the replacement forecasts for the medium and large replacement projects.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply line 38-366 Replace 4,383 feet of 8" Pipe in Lieu of ILI	00276.08
WITNESS	**IN SERVICE DATE**
Ray Stanford	08/31/2012

Small Job: Less than 200ft

Total Cost per replacement project:	$56,500	Per job
Labor (13%)	$6,500	Per job
Non-Labor (87%)	$50,000	Per job

Medium –Medium/Large: 200ft-15,000ft

Labor (2%)	2 % of Total	Per job
Non-Labor (200-1500)	$350	Per foot
Non-Labor (1500-15000)	$140	Per foot

Large Job: 15,000ft to 30,000ft

Labor (2%)	2% of total	Per job
Non-Labor (98%)	$55	Per foot

*Overall an additional $50,000 for each covered segment

<u>Small Replacement Project</u>

A single total project cost was used to forecast small replacement projects that involved replacement of less than 200 foot of pipe. This estimate was based on an average cost for similar sized jobs completed in Distribution BC 276 and BC 267 over the past three years from 2006 thru 2009. A cost of $56,500 total per project regardless of length (less than 200foot) was used to forecast planned replacement jobs.

A distribution of $6,500 Company labor and $50,000 non-labor costs was applied for small replacement projects.

<u>Medium to Medium/Large Replacement Projects</u>

A cost per foot factor for medium to medium/large sized replacement projects of greater than 200 foot and less than 15,000 foot was determined using data from previous replacement projects completed in BC 276 and BC 267 from 2006 thru 2009.
For medium replacement projects consisting of from 200 feet to 1,500 feet of HCA , a factor of $350 per foot of pipe was applied to the total HCA length to forecast replacement costs. For projects consisting of from 1,500 feet to 15,000 feet of HCA footage, a factor of $140 per foot of HCA was used to forecast replacement costs.
A distribution of 2% of the total cost was allocated to Company labor and the remainder of cost applied to non-labor costs on all forecast for medium to medium/large sized replacement projects.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply line 38-366 Replace 4,383 feet of 8" Pipe in Lieu of ILI	00276.08
WITNESS	**IN SERVICE DATE**
Ray Stanford	08/31/2012

Large Replacement Projects

A cost per foot factor for large sized replacement projects was determined using data from previous replacement projects ranging from 15,000 feet to 30,000 feet in length, completed in BC 276 and BC 267 from 2006 thru 2009.
For large replacement projects consisting of greater than 15,000 feet of HCA, a factor of $55 per foot of pipe was applied to the total HCA length to forecast replacement costs
A distribution of 2% of the total costs was allocated to Company labor and the remainder of cost applied to non-labor costs on all forecast for large sized replacement projects.

Pressure Reduction install Regulation Station Project:

To forecast costs related to installation of new pressure regulation stations in order to reduce pipeline pressure and operating stress two fixed cost per job were used based on historic costs to install this type of facility. For A small or Distribution regulation station a cost of $150,000 was used. For special or large Transmission Pressure Limiting station a cost of $300,000 was used.

Schedule
The completed capital portion of the project, referred to as in-service date for this project is: 08/31/2012.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E.   Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for replacement. A detailed study of the pipeline components is created. A plan is developed to remove/replace all identified sections of the pipeline. Permits are acquired, Materials are ordered and the job is awarded for construction to a contractor. Construction is started and completed depending on size and duration of job.

Year 2: When construction spans more than one year the remaining work is completed and pipeline is placed in service.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply Line 38-528 PI Replacement/Alteration	00276.09
WITNESS Ray Stanford	**IN SERVICE DATE** 04/30/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			13	4			17
DIRECT NONLABOR			1,038	346			1,384
TOTAL DIRECT CAPITAL			1,051	350			1,401
COLLECTIBLE	(0)	(0)	(0)	(0)	(0)	(0)	(0)
NET CAPITAL			1,051	350			1,401
FTE			0.1	0.0			0.1

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

In certain situations due to the pipe condition, location or environment it may be more economical to replace a pipeline with new pipe operating at lower stress which would not require baseline assessment or repeated re-assessment. This is often the case with short pipe segments and cross over piping. In those situations a pipeline may be replaced in lieu of retrofitting for internal inspection, if the construction can be implemented within the DOT mandated assessment schedule. Alternatively for some longer pipelines pressure reducing facilities (regulation station) may be installed to operate the pipeline at lower pressure and stress levels in lieu of repeated inspection per PSIA 2002.

Project Description

Replace 10,454 feet of 8”/10” pipe and install a distribution regulation station to reduce operating pressure and stress in SL 38-528 on CONEJO AV @ ELM AV FROM JCT SL 44-689 E'LY TO (ID 1334) KERN ST & "O" ST, near Kingsburg, California.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply Line 38-528 PI Replacement/Alteration	00276.09
WITNESS	**IN SERVICE DATE**
Ray Stanford	04/30/2011

repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following types of projects:

1. Small replacement job consisting of less than 200 feet of new pipe.
2. Medium replacement job consisting of 200 to 1,500 feet of new pipe.
3. Medium-Large replacement jobs consisting of 1,500 feet to 15,000 feet of new pipe.
4. Large replacement job consisting of greater than 15,000 feet of new pipe.
5. Installation of pressure reduction/control facilities to reduce pressure and operating stress

Often the work to complete replacement of a pipeline, in order to comply with PSIA 2002, spans more than one year. Based on experience with previous pipeline replacements, project expenditures are forecast over a two year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Small replacement job	75%	25%		100%
Medium replacement job	75%	25%		100%
Medium/Large replacement job	75%	25%		100%
Large replacement job	75%	25%		100%
Pressure Reduction facility	75%	25%		100%

Replacement Cost Forecast Component:

This activity is forecast using the scheduled number of pipelines identified for replacement and applying one of three cost factors depending on the size of the replacement job. The cost factors were arrived at using historic replacement cost data from 2006 through 2009. This is the period since the PSIA was passed where an increase in the level of this activity has occurred.

The cost factor is calculated based on actual Distribution pipeline replacement costs found both in BC 267 and 276 for jobs completed from 2006 thru 2009. A single cost per construction job was calculated for small projects consisting of replacement of less than 200 foot of pipe. A replacement cost per foot factor was calculated for medium to large jobs based on the total length of pipe installed. An additional mobilization/demobilization cost factor was used for each HCA segment equivalent in cost to a small job. The replacement cost per foot factor was multiplied by the project specific HCA miles to be replaced and the mob/demob cost factor was multiplied by the project specific HCA segments and added together to determine the replacement forecasts for the medium and large replacement projects.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply Line 38-528 PI Replacement/Alteration	00276.09
WITNESS	**IN SERVICE DATE**
Ray Stanford	04/30/2011

Small Job: Less than 200ft

Total Cost per replacement project:	$56,500	Per job
Labor (13%)	$6,500	Per job
Non-Labor (87%)	$50,000	Per job

Medium –Medium/Large: 200ft-15,000ft

Labor (2%)	2 % of Total	Per job
Non-Labor (200-1500)	$350	Per foot
Non-Labor (1500-15000)	$140	Per foot

Large Job: 15,000ft to 30,000ft

Labor (2%)	2% of total	Per job
Non-Labor (98%)	$55	Per foot

*Overall an additional $50,000 for each covered segment

<u>Small Replacement Project</u>

A single total project cost was used to forecast small replacement projects that involved replacement of less than 200 foot of pipe. This estimate was based on an average cost for similar sized jobs completed in Distribution BC 276 and BC 267 over the past three years from 2006 thru 2009. A cost of $56,500 total per project regardless of length (less than 200foot) was used to forecast planned replacement jobs.

A distribution of $6,500 Company labor and $50,000 non-labor costs was applied for small replacement projects.

<u>Medium to Medium/Large Replacement Projects</u>

A cost per foot factor for medium to medium/large sized replacement projects of greater than 200 foot and less than 15,000 foot was determined using data from previous replacement projects completed in BC 276 and BC 267 from 2006 thru 2009.
For medium replacement projects consisting of from 200 feet to 1,500 feet of HCA , a factor of $350 per foot of pipe was applied to the total HCA length to forecast replacement costs. For projects consisting of from 1,500 feet to 15,000 feet of HCA footage, a factor of $140 per foot of HCA was used to forecast replacement costs.
A distribution of 2% of the total cost was allocated to Company labor and the remainder of cost applied to non-labor costs on all forecast for medium to medium/large sized replacement projects.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply Line 38-528 PI Replacement/Alteration	00276.09
WITNESS	**IN SERVICE DATE**
Ray Stanford	04/30/2011

Large Replacement Projects

A cost per foot factor for large sized replacement projects was determined using data from previous replacement projects ranging from 15,000 feet to 30,000 feet in length, completed in BC 276 and BC 267 from 2006 thru 2009.
For large replacement projects consisting of greater than 15,000 feet of HCA, a factor of $55 per foot of pipe was applied to the total HCA length to forecast replacement costs
A distribution of 2% of the total costs was allocated to Company labor and the remainder of cost applied to non-labor costs on all forecast for large sized replacement projects.

Pressure Reduction install Regulation Station Project:

To forecast costs related to installation of new pressure regulation stations in order to reduce pipeline pressure and operating stress two fixed cost per job were used based on historic costs to install this type of facility. For A small or Distribution regulation station a cost of $150,000 was used. For special or large Transmission Pressure Limiting station a cost of $300,000 was used.

Schedule
The completed capital portion of the project, referred to as in-service date for this project is: 04/30/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E.   Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for replacement. A detailed study of the pipeline components is created. A plan is developed to remove/replace all identified sections of the pipeline. Permits are acquired, Materials are ordered and the job is awarded for construction to a contractor. Construction is started and completed depending on size and duration of job.

Year 2: When construction spans more than one year the remaining work is completed and pipeline is placed in service.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply Line 38-351 PI Replacement/Alteration	00276.10
WITNESS Ray Stanford	**IN SERVICE DATE** 04/30/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				31	10		41
DIRECT NONLABOR				1,868	623		2,491
TOTAL DIRECT CAPITAL				1,899	633		2,532
COLLECTIBLE	(0)	(0)	(0)	(0)	(0)		
NET CAPITAL				1,899	633		2,532
FTE				0.3	0.1		0.4

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

In certain situations due to the pipe condition, location or environment it may be more economical to replace a pipeline with new pipe operating at lower stress which would not require baseline assessment or repeated re-assessment. This is often the case with short pipe segments and cross over piping. In those situations a pipeline may be replaced in lieu of retrofitting for internal inspection, if the construction can be implemented within the DOT mandated assessment schedule. Alternatively for some longer pipelines pressure reducing facilities (regulation station) may be installed to operate the pipeline at lower pressure and stress levels in lieu of repeated inspection per PSIA 2002.

Project Description

Install 14,000 feet of new 8" pipeline and a new Distribution high to high regulation station and convert existing SL 38-351 to medium pressure service in Delano, California.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply Line 38-351 PI Replacement/Alteration	00276.10
WITNESS	IN SERVICE DATE
Ray Stanford	04/30/2012

and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following types of projects:

1. Small replacement job consisting of less than 200 feet of new pipe.
2. Medium replacement job consisting of 200 to 1,500 feet of new pipe.
3. Medium-Large replacement jobs consisting of 1,500 feet to 15,000 feet of new pipe.
4. Large replacement job consisting of greater than 15,000 feet of new pipe.
5. Installation of pressure reduction/control facilities to reduce pressure and operating stress

Often the work to complete replacement of a pipeline, in order to comply with PSIA 2002, spans more than one year. Based on experience with previous pipeline replacements, project expenditures are forecast over a two year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Small replacement job	75%	25%		100%
Medium replacement job	75%	25%		100%
Medium/Large replacement job	75%	25%		100%
Large replacement job	75%	25%		100%
Pressure Reduction facility	75%	25%		100%

Replacement Cost Forecast Component:

This activity is forecast using the scheduled number of pipelines identified for replacement and applying one of three cost factors depending on the size of the replacement job. The cost factors were arrived at using historic replacement cost data from 2006 through 2009. This is the period since the PSIA was passed where an increase in the level of this activity has occurred.

The cost factor is calculated based on actual Distribution pipeline replacement costs found both in BC 267 and 276 for jobs completed from 2006 thru 2009. A single cost per construction job was calculated for small projects consisting of replacement of less than 200 foot of pipe. A replacement cost per foot factor was calculated for medium to large jobs based on the total length of pipe installed. An additional mobilization/demobilization cost factor was used for each HCA segment equivalent in cost to a small job. The replacement cost per foot factor was multiplied by the project specific HCA miles to be replaced and the mob/demob cost factor was multiplied by the project specific HCA segments and added together to determine the replacement forecasts for the medium and large replacement projects.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply Line 38-351 PI Replacement/Alteration	00276.10
WITNESS	**IN SERVICE DATE**
Ray Stanford	04/30/2012

Small Job: Less than 200ft

Total Cost per replacement project:	$56,500	Per job
Labor (13%)	$6,500	Per job
Non-Labor (87%)	$50,000	Per job

Medium –Medium/Large: 200ft-15,000ft

Labor (2%)	2 % of Total	Per job
Non-Labor (200-1500)	$350	Per foot
Non-Labor (1500-15000)	$140	Per foot

Large Job: 15,000ft to 30,000ft

Labor (2%)	2% of total	Per job
Non-Labor (98%)	$55	Per foot

*Overall an additional $50,000 for each covered segment

<u>Small Replacement Project</u>

A single total project cost was used to forecast small replacement projects that involved replacement of less than 200 foot of pipe. This estimate was based on an average cost for similar sized jobs completed in Distribution BC 276 and BC 267 over the past three years from 2006 thru 2009. A cost of $56,500 total per project regardless of length (less than 200foot) was used to forecast planned replacement jobs.

A distribution of $6,500 Company labor and $50,000 non-labor costs was applied for small replacement projects.

<u>Medium to Medium/Large Replacement Projects</u>

A cost per foot factor for medium to medium/large sized replacement projects of greater than 200 foot and less than 15,000 foot was determined using data from previous replacement projects completed in BC 276 and BC 267 from 2006 thru 2009.
For medium replacement projects consisting of from 200 feet to 1,500 feet of HCA , a factor of $350 per foot of pipe was applied to the total HCA length to forecast replacement costs. For projects consisting of from 1,500 feet to 15,000 feet of HCA footage, a factor of $140 per foot of HCA was used to forecast replacement costs.
A distribution of 2% of the total cost was allocated to Company labor and the remainder of cost applied to non-labor costs on all forecast for medium to medium/large sized replacement projects.

<u>Large Replacement Projects</u>

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply Line 38-351 PI Replacement/Alteration	00276.10
WITNESS	**IN SERVICE DATE**
Ray Stanford	04/30/2012

A cost per foot factor for large sized replacement projects was determined using data from previous replacement projects ranging from 15,000 feet to 30,000 feet in length, completed in BC 276 and BC 267 from 2006 thru 2009.
For large replacement projects consisting of greater than 15,000 feet of HCA, a factor of $55 per foot of pipe was applied to the total HCA length to forecast replacement costs
A distribution of 2% of the total costs was allocated to Company labor and the remainder of cost applied to non-labor costs on all forecast for large sized replacement projects.

Pressure Reduction install Regulation Station Project:

To forecast costs related to installation of new pressure regulation stations in order to reduce pipeline pressure and operating stress two fixed cost per job were used based on historic costs to install this type of facility. For A small or Distribution regulation station a cost of $150,000 was used. For special or large Transmission Pressure Limiting station a cost of $300,000 was used.

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 04/30/2012.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for replacement. A detailed study of the pipeline components is created. A plan is developed to remove/replace all identified sections of the pipeline. Permits are acquired, Materials are ordered and the job is awarded for construction to a contractor. Construction is started and completed depending on size and duration of job.

Year 2: When construction spans more than one year the remaining work is completed and pipeline is placed in service.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply Line 42-46 PI Replacement/Alteration	00276.11
WITNESS	**IN SERVICE DATE**
Ray Stanford	02/28/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				11	4		15
DIRECT NONLABOR				1,091	364		1,455
TOTAL DIRECT CAPITAL				1,102	368		1470
COLLECTIBLE	(0)	(0)	(0)	(0)	(0)	(0)	(0)
NET CAPITAL				1,102	368		1470
FTE				0.1	0.0		0.1

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

In certain situations due to the pipe condition, location or environment it may be more economical to replace a pipeline with new pipe operating at lower stress which would not require baseline assessment or repeated re-assessment. This is often the case with short pipe segments and cross over piping. In those situations a pipeline may be replaced in lieu of retrofitting for internal inspection, if the construction can be implemented within the DOT mandated assessment schedule. Alternatively for some longer pipelines pressure reducing facilities (regulation station) may be installed to operate the pipeline at lower pressure and stress levels in lieu of repeated inspection per PSIA 2002.

Project Description

Replace 5,290 feet of 16” pipe in Garden Grove and Golden west Blvd near in Westminster California.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply Line 42-46 PI Replacement/Alteration	00276.11
WITNESS	**IN SERVICE DATE**
Ray Stanford	02/28/2012

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following types of projects:

1. Small replacement job consisting of less than 200 feet of new pipe.
2. Medium replacement job consisting of 200 to 1,500 feet of new pipe.
3. Medium-Large replacement jobs consisting of 1,500 feet to 15,000 feet of new pipe.
4. Large replacement job consisting of greater than 15,000 feet of new pipe.
5. Installation of pressure reduction/control facilities to reduce pressure and operating stress

Often the work to complete replacement of a pipeline, in order to comply with PSIA 2002, spans more than one year. Based on experience with previous pipeline replacements, project expenditures are forecast over a two year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Small replacement job	75%	25%		100%
Medium replacement job	75%	25%		100%
Medium/Large replacement job	75%	25%		100%
Large replacement job	75%	25%		100%
Pressure Reduction facility	75%	25%		100%

Replacement Cost Forecast Component:

This activity is forecast using the scheduled number of pipelines identified for replacement and applying one of three cost factors depending on the size of the replacement job. The cost factors were arrived at using historic replacement cost data from 2006 through 2009. This is the period since the PSIA was passed where an increase in the level of this activity has occurred.

The cost factor is calculated based on actual Distribution pipeline replacement costs found both in BC 267 and 276 for jobs completed from 2006 thru 2009. A single cost per construction job was calculated for small projects consisting of replacement of less than 200 foot of pipe. A replacement cost per foot factor was calculated for medium to large jobs based on the total length of pipe installed. An additional mobilization/demobilization cost factor was used for each HCA segment equivalent in cost to a small job. The replacement cost per foot factor was multiplied by the project specific HCA miles to be replaced and the mob/demob cost factor was multiplied by the project specific HCA segments and added together to determine the replacement forecasts for the medium and large replacement projects.

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply Line 42-46 PI Replacement/Alteration	00276.11
WITNESS	**IN SERVICE DATE**
Ray Stanford	02/28/2012

Small Job: Less than 200ft

Total Cost per replacement project:	$56,500	Per job
Labor (13%)	$6,500	Per job
Non-Labor (87%)	$50,000	Per job

Medium –Medium/Large: 200ft-15,000ft

Labor (2%)	2 % of Total	Per job
Non-Labor (200-1500)	$350	Per foot
Non-Labor (1500-15000)	$140	Per foot

Large Job: 15,000ft to 30,000ft

Labor (2%)	2% of total	Per job
Non-Labor (98%)	$55	Per foot

*Overall an additional $50,000 for each covered segment

Small Replacement Project

A single total project cost was used to forecast small replacement projects that involved replacement of less than 200 foot of pipe. This estimate was based on an average cost for similar sized jobs completed in Distribution BC 276 and BC 267 over the past three years from 2006 thru 2009. A cost of $56,500 total per project regardless of length (less than 200foot) was used to forecast planned replacement jobs.

A distribution of $6,500 Company labor and $50,000 non-labor costs was applied for small replacement projects.

Medium to Medium/Large Replacement Projects

A cost per foot factor for medium to medium/large sized replacement projects of greater than 200 foot and less than 15,000 foot was determined using data from previous replacement projects completed in BC 276 and BC 267 from 2006 thru 2009.
For medium replacement projects consisting of from 200 feet to 1,500 feet of HCA , a factor of $350 per foot of pipe was applied to the total HCA length to forecast replacement costs. For projects consisting of from 1,500 feet to 15,000 feet of HCA footage, a factor of $140 per foot of HCA was used to forecast replacement costs.
A distribution of 2% of the total cost was allocated to Company labor and the remainder of cost applied to non-labor costs on all forecast for medium to medium/large sized replacement projects.

Large Replacement Projects

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply Line 42-46 PI Replacement/Alteration	00276.11
WITNESS	**IN SERVICE DATE**
Ray Stanford	02/28/2012

A cost per foot factor for large sized replacement projects was determined using data from previous replacement projects ranging from 15,000 feet to 30,000 feet in length, completed in BC 276 and BC 267 from 2006 thru 2009.
For large replacement projects consisting of greater than 15,000 feet of HCA, a factor of $55 per foot of pipe was applied to the total HCA length to forecast replacement costs
A distribution of 2% of the total costs was allocated to Company labor and the remainder of cost applied to non-labor costs on all forecast for large sized replacement projects.

Pressure Reduction install Regulation Station Project:

To forecast costs related to installation of new pressure regulation stations in order to reduce pipeline pressure and operating stress two fixed cost per job were used based on historic costs to install this type of facility. For A small or Distribution regulation station a cost of $150,000 was used. For special or large Transmission Pressure Limiting station a cost of $300,000 was used.

Schedule
The completed capital portion of the project, referred to as in-service date for this project is: 02/28/2012.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for replacement. A detailed study of the pipeline components is created. A plan is developed to remove/replace all identified sections of the pipeline. Permits are acquired, Materials are ordered and the job is awarded for construction to a contractor. Construction is started and completed depending on size and duration of job.

Year 2: When construction spans more than one year the remaining work is completed and pipeline is placed in service.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven SL 42-46F Replace 1,000 feet of 10" pipeline in Bolsa Ave, Seal Beach, California	00276.12
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			6	2			8
DIRECT NONLABOR			634	211			845
TOTAL DIRECT CAPITAL			640	213			853
COLLECTIBLE	(0)	(0)	(0)	(0)	(0)	(0)	(0)
NET CAPITAL			640	213			853
FTE			0.1	0.0			0.1

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

In certain situations due to the pipe condition, location or environment it may be more economical to replace a pipeline with new pipe operating at lower stress which would not require baseline assessment or repeated re-assessment. This is often the case with short pipe segments and cross over piping. In those situations a pipeline may be replaced in lieu of retrofitting for internal inspection, if the construction can be implemented within the DOT mandated assessment schedule. Alternatively for some longer pipelines pressure reducing facilities (regulation station) may be installed to operate the pipeline at lower pressure and stress levels in lieu of repeated inspection per PSIA 2002.

Project Description

Replace 1,000 feet of 10" pipeline SL 42-46F in Bolsa Ave, Seal Beach, California

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven SL 42-46F Replace 1,000 feet of 10" pipeline in Bolsa Ave, Seal Beach, California	00276.12
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2011

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following types of projects:
1. Small replacement job consisting of less than 200 feet of new pipe.
2. Medium replacement job consisting of 200 to 1,500 feet of new pipe.
3. Medium-Large replacement jobs consisting of 1,500 feet to 15,000 feet of new pipe.
4. Large replacement job consisting of greater than 15,000 feet of new pipe.
5. Installation of pressure reduction/control facilities to reduce pressure and operating stress

Often the work to complete replacement of a pipeline, in order to comply with PSIA 2002, spans more than one year. Based on experience with previous pipeline replacements, project expenditures are forecast over a two year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Small replacement job	75%	25%		100%
Medium replacement job	75%	25%		100%
Medium/Large replacement job	75%	25%		100%
Large replacement job	75%	25%		100%
Pressure Reduction facility	75%	25%		100%

Replacement Cost Forecast Component:

This activity is forecast using the scheduled number of pipelines identified for replacement and applying one of three cost factors depending on the size of the replacement job. The cost factors were arrived at using historic replacement cost data from 2006 through 2009. This is the period since the PSIA was passed where an increase in the level of this activity has occurred.

The cost factor is calculated based on actual Distribution pipeline replacement costs found both in BC 267 and 276 for jobs completed from 2006 thru 2009. A single cost per construction job was calculated for small projects consisting of replacement of less than 200 foot of pipe. A replacement cost per foot factor was calculated for medium to large jobs based on the total length of pipe installed. An additional mobilization/demobilization cost factor was used for each HCA segment equivalent in cost to a small job. The replacement cost per foot factor was multiplied by the project specific HCA miles to be replaced and the mob/demob cost factor was multiplied by the project specific HCA segments and added together to determine the replacement forecasts for the medium and large replacement projects.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven SL 42-46F Replace 1,000 feet of 10" pipeline in Bolsa Ave, Seal Beach, California	00276.12
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2011

Small Job: Less than 200ft

Total Cost per replacement project:	$56,500	Per job
Labor (13%)	$6,500	Per job
Non-Labor (87%)	$50,000	Per job

Medium –Medium/Large: 200ft-15,000ft

Labor (2%)	2 % of Total	Per job
Non-Labor (200-1500)	$350	Per foot
Non-Labor (1500-15000)	$140	Per foot

Large Job: 15,000ft to 30,000ft

Labor (2%)	2% of total	Per job
Non-Labor (98%)	$55	Per foot

*Overall an additional $50,000 for each covered segment

Small Replacement Project

A single total project cost was used to forecast small replacement projects that involved replacement of less than 200 foot of pipe. This estimate was based on an average cost for similar sized jobs completed in Distribution BC 276 and BC 267 over the past three years from 2006 thru 2009. A cost of $56,500 total per project regardless of length (less than 200foot) was used to forecast planned replacement jobs.

A distribution of $6,500 Company labor and $50,000 non-labor costs was applied for small replacement projects.

Medium to Medium/Large Replacement Projects

A cost per foot factor for medium to medium/large sized replacement projects of greater than 200 foot and less than 15,000 foot was determined using data from previous replacement projects completed in BC 276 and BC 267 from 2006 thru 2009.
For medium replacement projects consisting of from 200 feet to 1,500 feet of HCA , a factor of $350 per foot of pipe was applied to the total HCA length to forecast replacement costs. For projects consisting of from 1,500 feet to 15,000 feet of HCA footage, a factor of $140 per foot of HCA was used to forecast replacement costs.
A distribution of 2% of the total cost was allocated to Company labor and the remainder of cost applied to non-labor costs on all forecast for medium to medium/large sized replacement projects.

Large Replacement Projects

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven SL 42-46F Replace 1,000 feet of 10" pipeline in Bolsa Ave, Seal Beach, California	00276.12
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2011

A cost per foot factor for large sized replacement projects was determined using data from previous replacement projects ranging from 15,000 feet to 30,000 feet in length, completed in BC 276 and BC 267 from 2006 thru 2009.
For large replacement projects consisting of greater than 15,000 feet of HCA, a factor of $55 per foot of pipe was applied to the total HCA length to forecast replacement costs
A distribution of 2% of the total costs was allocated to Company labor and the remainder of cost applied to non-labor costs on all forecast for large sized replacement projects.

Pressure Reduction install Regulation Station Project:

To forecast costs related to installation of new pressure regulation stations in order to reduce pipeline pressure and operating stress two fixed cost per job were used based on historic costs to install this type of facility. For A small or Distribution regulation station a cost of $150,000 was used. For special or large Transmission Pressure Limiting station a cost of $300,000 was used.

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 01/31/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for replacement. A detailed study of the pipeline components is created. A plan is developed to remove/replace all identified sections of the pipeline. Permits are acquired, Materials are ordered and the job is awarded for construction to a contractor. Construction is started and completed depending on size and duration of job.

Year 2: When construction spans more than one year the remaining work is completed and pipeline is placed in service.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply line 41-43 Pipe Replacement Project	00276.13
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				25	8		33
DIRECT NONLABOR				1,384	461		1,845
TOTAL DIRECT CAPITAL				1,409	469		1,878
COLLECTIBLE	(0)	(0)	(0)	(0)	(0)	(0)	(0)
NET CAPITAL				1,409	469		1,878
FTE				0.3	0.1		0.4

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

In certain situations due to the pipe condition, location or environment it may be more economical to replace a pipeline with new pipe operating at lower stress which would not require baseline assessment or repeated re-assessment. This is often the case with short pipe segments and cross over piping. In those situations a pipeline may be replaced in lieu of retrofitting for internal inspection, if the construction can be implemented within the DOT mandated assessment schedule. Alternatively for some longer pipelines pressure reducing facilities (regulation station) may be installed to operate the pipeline at lower pressure and stress levels in lieu of repeated inspection per PSIA 2002.

Project Description

Replace 12,000 feet of 6" pipe SL 41-43 with 12" pipe in Calimesa Blvd, near Calimesa, California

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply line 41-43 Pipe Replacement Project	00276.13
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2012

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following types of projects:

1. Small replacement job consisting of less than 200 feet of new pipe.
2. Medium replacement job consisting of 200 to 1,500 feet of new pipe.
3. Medium-Large replacement jobs consisting of 1,500 feet to 15,000 feet of new pipe.
4. Large replacement job consisting of greater than 15,000 feet of new pipe.
5. Installation of pressure reduction/control facilities to reduce pressure and operating stress

Often the work to complete replacement of a pipeline, in order to comply with PSIA 2002, spans more than one year. Based on experience with previous pipeline replacements, project expenditures are forecast over a two year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Small replacement job	75%	25%		100%
Medium replacement job	75%	25%		100%
Medium/Large replacement job	75%	25%		100%
Large replacement job	75%	25%		100%
Pressure Reduction facility	75%	25%		100%

Replacement Cost Forecast Component:

This activity is forecast using the scheduled number of pipelines identified for replacement and applying one of three cost factors depending on the size of the replacement job. The cost factors were arrived at using historic replacement cost data from 2006 through 2009. This is the period since the PSIA was passed where an increase in the level of this activity has occurred.

The cost factor is calculated based on actual Distribution pipeline replacement costs found both in BC 267 and 276 for jobs completed from 2006 thru 2009. A single cost per construction job was calculated for small projects consisting of replacement of less than 200 foot of pipe. A replacement cost per foot factor was calculated for medium to large jobs based on the total length of pipe installed. An additional mobilization/demobilization cost factor was used for each HCA segment equivalent in cost to a small job. The replacement cost per foot factor was multiplied by the project specific HCA miles to be replaced and the mob/demob cost factor was multiplied by the project specific HCA segments and added together to determine the replacement forecasts for the medium and large replacement projects.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply line 41-43 Pipe Replacement Project	00276.13
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2012

Small Job: Less than 200ft

Total Cost per replacement project:	$56,500	Per job
Labor (13%)	$6,500	Per job
Non-Labor (87%)	$50,000	Per job

Medium –Medium/Large: 200ft-15,000ft

Labor (2%)	2 % of Total	Per job
Non-Labor (200-1500)	$350	Per foot
Non-Labor (1500-15000)	$140	Per foot

Large Job: 15,000ft to 30,000ft

Labor (2%)	2% of total	Per job
Non-Labor (98%)	$55	Per foot

*Overall an additional $50,000 for each covered segment

<u>Small Replacement Project</u>

A single total project cost was used to forecast small replacement projects that involved replacement of less than 200 foot of pipe. This estimate was based on an average cost for similar sized jobs completed in Distribution BC 276 and BC 267 over the past three years from 2006 thru 2009. A cost of $56,500 total per project regardless of length (less than 200foot) was used to forecast planned replacement jobs.

A distribution of $6,500 Company labor and $50,000 non-labor costs was applied for small replacement projects.

<u>Medium to Medium/Large Replacement Projects</u>

A cost per foot factor for medium to medium/large sized replacement projects of greater than 200 foot and less than 15,000 foot was determined using data from previous replacement projects completed in BC 276 and BC 267 from 2006 thru 2009.
For medium replacement projects consisting of from 200 feet to 1,500 feet of HCA , a factor of $350 per foot of pipe was applied to the total HCA length to forecast replacement costs. For projects consisting of from 1,500 feet to 15,000 feet of HCA footage, a factor of $140 per foot of HCA was used to forecast replacement costs.
A distribution of 2% of the total cost was allocated to Company labor and the remainder of cost applied to non-labor costs on all forecast for medium to medium/large sized replacement projects.

<u>Large Replacement Projects</u>

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply line 41-43 Pipe Replacement Project	00276.13
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2012

A cost per foot factor for large sized replacement projects was determined using data from previous replacement projects ranging from 15,000 feet to 30,000 feet in length, completed in BC 276 and BC 267 from 2006 thru 2009.
For large replacement projects consisting of greater than 15,000 feet of HCA, a factor of $55 per foot of pipe was applied to the total HCA length to forecast replacement costs
A distribution of 2% of the total costs was allocated to Company labor and the remainder of cost applied to non-labor costs on all forecast for large sized replacement projects.

Pressure Reduction install Regulation Station Project:

To forecast costs related to installation of new pressure regulation stations in order to reduce pipeline pressure and operating stress two fixed cost per job were used based on historic costs to install this type of facility. For A small or Distribution regulation station a cost of $150,000 was used. For special or large Transmission Pressure Limiting station a cost of $300,000 was used.

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 01/31/2012.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for replacement. A detailed study of the pipeline components is created. A plan is developed to remove/replace all identified sections of the pipeline. Permits are acquired, Materials are ordered and the job is awarded for construction to a contractor. Construction is started and completed depending on size and duration of job.

Year 2: When construction spans more than one year the remaining work is completed and pipeline is placed in service.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply line 36-1008-A Replacement project	00276.14
WITNESS Ray Stanford	**IN SERVICE DATE** 02/28/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				13	4		17
DIRECT NONLABOR				621	207		828
TOTAL DIRECT CAPITAL				634	211		845
COLLECTIBLE	(0)	(0)	(0)	(0)	(0)	(0)	(0)
NET CAPITAL				634	211		845
FTE				0.1	0.0		0.2

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

In certain situations due to the pipe condition, location or environment it may be more economical to replace a pipeline with new pipe operating at lower stress which would not require baseline assessment or repeated re-assessment. This is often the case with short pipe segments and cross over piping. In those situations a pipeline may be replaced in lieu of retrofitting for internal inspection, if the construction can be implemented within the DOT mandated assessment schedule. Alternatively for some longer pipelines pressure reducing facilities (regulation station) may be installed to operate the pipeline at lower pressure and stress levels in lieu of repeated inspection per PSIA 2002.

Project Description

Replace 5,914 feet of 10" pipeline SL 36-1008-A from Curbaril Ave to Portola rd. , near Atascadero, California.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply line 36-1008-A Replacement project	00276.14
WITNESS	**IN SERVICE DATE**
Ray Stanford	02/28/2012

and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following types of projects:

1. Small replacement job consisting of less than 200 feet of new pipe.
2. Medium replacement job consisting of 200 to 1,500 feet of new pipe.
3. Medium-Large replacement jobs consisting of 1,500 feet to 15,000 feet of new pipe.
4. Large replacement job consisting of greater than 15,000 feet of new pipe.
5. Installation of pressure reduction/control facilities to reduce pressure and operating stress

Often the work to complete replacement of a pipeline, in order to comply with PSIA 2002, spans more than one year. Based on experience with previous pipeline replacements, project expenditures are forecast over a two year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Small replacement job	75%	25%		100%
Medium replacement job	75%	25%		100%
Medium/Large replacement job	75%	25%		100%
Large replacement job	75%	25%		100%
Pressure Reduction facility	75%	25%		100%

Replacement Cost Forecast Component:

This activity is forecast using the scheduled number of pipelines identified for replacement and applying one of three cost factors depending on the size of the replacement job. The cost factors were arrived at using historic replacement cost data from 2006 through 2009. This is the period since the PSIA was passed where an increase in the level of this activity has occurred.

The cost factor is calculated based on actual Distribution pipeline replacement costs found both in BC 267 and 276 for jobs completed from 2006 thru 2009. A single cost per construction job was calculated for small projects consisting of replacement of less than 200 foot of pipe. A replacement cost per foot factor was calculated for medium to large jobs based on the total length of pipe installed. An additional mobilization/demobilization cost factor was used for each HCA segment equivalent in cost to a small job. The replacement cost per foot factor was multiplied by the project specific HCA miles to be replaced and the mob/demob cost factor was multiplied by the project specific HCA segments and added together to determine the replacement forecasts for the medium and large replacement projects.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply line 36-1008-A Replacement project	00276.14
WITNESS	**IN SERVICE DATE**
Ray Stanford	02/28/2012

Small Job: Less than 200ft

Total Cost per replacement project:	$56,500	Per job
Labor (13%)	$6,500	Per job
Non-Labor (87%)	$50,000	Per job

Medium –Medium/Large: 200ft-15,000ft

Labor (2%)	2 % of Total	Per job
Non-Labor (200-1500)	$350	Per foot
Non-Labor (1500-15000)	$140	Per foot

Large Job: 15,000ft to 30,000ft

Labor (2%)	2% of total	Per job
Non-Labor (98%)	$55	Per foot

*Overall an additional $50,000 for each covered segment

<u>Small Replacement Project</u>

A single total project cost was used to forecast small replacement projects that involved replacement of less than 200 foot of pipe. This estimate was based on an average cost for similar sized jobs completed in Distribution BC 276 and BC 267 over the past three years from 2006 thru 2009. A cost of $56,500 total per project regardless of length (less than 200foot) was used to forecast planned replacement jobs.

A distribution of $6,500 Company labor and $50,000 non-labor costs was applied for small replacement projects.

<u>Medium to Medium/Large Replacement Projects</u>

A cost per foot factor for medium to medium/large sized replacement projects of greater than 200 foot and less than 15,000 foot was determined using data from previous replacement projects completed in BC 276 and BC 267 from 2006 thru 2009.
For medium replacement projects consisting of from 200 feet to 1,500 feet of HCA , a factor of $350 per foot of pipe was applied to the total HCA length to forecast replacement costs. For projects consisting of from 1,500 feet to 15,000 feet of HCA footage, a factor of $140 per foot of HCA was used to forecast replacement costs.
A distribution of 2% of the total cost was allocated to Company labor and the remainder of cost applied to non-labor costs on all forecast for medium to medium/large sized replacement projects.

<u>Large Replacement Projects</u>

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply line 36-1008-A Replacement project	00276.14
WITNESS	**IN SERVICE DATE**
Ray Stanford	02/28/2012

A cost per foot factor for large sized replacement projects was determined using data from previous replacement projects ranging from 15,000 feet to 30,000 feet in length, completed in BC 276 and BC 267 from 2006 thru 2009.
For large replacement projects consisting of greater than 15,000 feet of HCA, a factor of $55 per foot of pipe was applied to the total HCA length to forecast replacement costs
A distribution of 2% of the total costs was allocated to Company labor and the remainder of cost applied to non-labor costs on all forecast for large sized replacement projects.

Pressure Reduction install Regulation Station Project:

To forecast costs related to installation of new pressure regulation stations in order to reduce pipeline pressure and operating stress two fixed cost per job were used based on historic costs to install this type of facility. For A small or Distribution regulation station a cost of $150,000 was used. For special or large Transmission Pressure Limiting station a cost of $300,000 was used.

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 02/28/2012.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for replacement. A detailed study of the pipeline components is created. A plan is developed to remove/replace all identified sections of the pipeline. Permits are acquired, Materials are ordered and the job is awarded for construction to a contractor. Construction is started and completed depending on size and duration of job.

Year 2: When construction spans more than one year the remaining work is completed and pipeline is placed in service.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply line 38-202 Replacement of 8,818 feet of 12" Pipe in Lieu of ILI	00276.15
WITNESS Ray Stanford	**IN SERVICE DATE** 01/31/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			22	6			28
DIRECT NONLABOR			1,050	350			1,400
TOTAL DIRECT CAPITAL			1,072	356			1,428
COLLECTIBLE	(0)	(0)	(0)	(0)	(0)	(0)	(0)
NET CAPITAL			1,072	356			1,428
FTE			0.2	0.1			0.3

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

In certain situations due to the pipe condition, location or environment it may be more economical to replace a pipeline with new pipe operating at lower stress which would not require baseline assessment or repeated re-assessment. This is often the case with short pipe segments and cross over piping. In those situations a pipeline may be replaced in lieu of retrofitting for internal inspection, if the construction can be implemented within the DOT mandated assessment schedule. Alternatively for some longer pipelines pressure reducing facilities (regulation station) may be installed to operate the pipeline at lower pressure and stress levels in lieu of repeated inspection per PSIA 2002.

Project Description

Replace 8,818 feet of 12" pipeline SL38-202 in Norris Rd, Oildale, California

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply line 38-202 Replacement of 8,818 feet of 12" Pipe in Lieu of ILI	00276.15
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2011

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following types of projects:

1. Small replacement job consisting of less than 200 feet of new pipe.
2. Medium replacement job consisting of 200 to 1,500 feet of new pipe.
3. Medium-Large replacement jobs consisting of 1,500 feet to 15,000 feet of new pipe.
4. Large replacement job consisting of greater than 15,000 feet of new pipe.
5. Installation of pressure reduction/control facilities to reduce pressure and operating stress

Often the work to complete replacement of a pipeline, in order to comply with PSIA 2002, spans more than one year. Based on experience with previous pipeline replacements, project expenditures are forecast over a two year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Small replacement job	75%	25%		100%
Medium replacement job	75%	25%		100%
Medium/Large replacement job	75%	25%		100%
Large replacement job	75%	25%		100%
Pressure Reduction facility	75%	25%		100%

Replacement Cost Forecast Component:

This activity is forecast using the scheduled number of pipelines identified for replacement and applying one of three cost factors depending on the size of the replacement job. The cost factors were arrived at using historic replacement cost data from 2006 through 2009. This is the period since the PSIA was passed where an increase in the level of this activity has occurred.

The cost factor is calculated based on actual Distribution pipeline replacement costs found both in BC 267 and 276 for jobs completed from 2006 thru 2009. A single cost per construction job was calculated for small projects consisting of replacement of less than 200 foot of pipe. A replacement cost per foot factor was calculated for medium to large jobs based on the total length of pipe installed. An additional mobilization/demobilization cost factor was used for each HCA segment equivalent in cost to a small job. The replacement cost per foot factor was multiplied by the project specific HCA miles to be replaced and the mob/demob cost factor was multiplied by the project specific HCA segments and added together to determine the replacement forecasts for the medium and large replacement projects.

Small Job: Less than 200ft

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply line 38-202 Replacement of 8,818 feet of 12" Pipe in Lieu of ILI	00276.15
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2011

Total Cost per replacement project:	$56,500	Per job
Labor (13%)	$6,500	Per job
Non-Labor (87%)	$50,000	Per job

Medium –Medium/Large: 200ft-15,000ft

Labor (2%)	2 % of Total	Per job
Non-Labor (200-1500)	$350	Per foot
Non-Labor (1500-15000)	$140	Per foot

Large Job: 15,000ft to 30,000ft

Labor (2%)	2% of total	Per job
Non-Labor (98%)	$55	Per foot

*Overall an additional $50,000 for each covered segment

Small Replacement Project

A single total project cost was used to forecast small replacement projects that involved replacement of less than 200 foot of pipe. This estimate was based on an average cost for similar sized jobs completed in Distribution BC 276 and BC 267 over the past three years from 2006 thru 2009. A cost of $56,500 total per project regardless of length (less than 200foot) was used to forecast planned replacement jobs.

A distribution of $6,500 Company labor and $50,000 non-labor costs was applied for small replacement projects.

Medium to Medium/Large Replacement Projects

A cost per foot factor for medium to medium/large sized replacement projects of greater than 200 foot and less than 15,000 foot was determined using data from previous replacement projects completed in BC 276 and BC 267 from 2006 thru 2009.
For medium replacement projects consisting of from 200 feet to 1,500 feet of HCA , a factor of $350 per foot of pipe was applied to the total HCA length to forecast replacement costs. For projects consisting of from 1,500 feet to 15,000 feet of HCA footage, a factor of $140 per foot of HCA was used to forecast replacement costs.
A distribution of 2% of the total cost was allocated to Company labor and the remainder of cost applied to non-labor costs on all forecast for medium to medium/large sized replacement projects.

Large Replacement Projects

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Supply line 38-202 Replacement of 8,818 feet of 12" Pipe in Lieu of ILI	00276.15
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2011

A cost per foot factor for large sized replacement projects was determined using data from previous replacement projects ranging from 15,000 feet to 30,000 feet in length, completed in BC 276 and BC 267 from 2006 thru 2009.
For large replacement projects consisting of greater than 15,000 feet of HCA, a factor of $55 per foot of pipe was applied to the total HCA length to forecast replacement costs
A distribution of 2% of the total costs was allocated to Company labor and the remainder of cost applied to non-labor costs on all forecast for large sized replacement projects.

Pressure Reduction install Regulation Station Project:

To forecast costs related to installation of new pressure regulation stations in order to reduce pipeline pressure and operating stress two fixed cost per job were used based on historic costs to install this type of facility. For A small or Distribution regulation station a cost of $150,000 was used. For special or large Transmission Pressure Limiting station a cost of $300,000 was used.

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 01/31/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for replacement. A detailed study of the pipeline components is created. A plan is developed to remove/replace all identified sections of the pipeline. Permits are acquired, Materials are ordered and the job is awarded for construction to a contractor. Construction is started and completed depending on size and duration of job.

Year 2: When construction spans more than one year the remaining work is completed and pipeline is placed in service.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Capital Improvement / Externally Driven Casing Removals & Tethered Inspections - Blanket	00276.16
WITNESS Ray Stanford	IN SERVICE DATE Blanket

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			129	527	899		1555
DIRECT NONLABOR			1,627	5,256	8,487		15,370
TOTAL DIRECT CAPITAL			1,756	5,783	9,386		16,925
COLLECTIBLE			0	0	0		0
NET CAPITAL			1,756	5,783	9,386		16,925
FTE			1.4	5.7	9.8		16.9

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

Remove approximately thirty-two (32) casings from carrier pipe in order to facilitate the direct examination of the carrier to comply with the baseline assessment and future re-assessment requirements of the Federal Pipeline Safety Improvement Act of 2002.

Conduct tethered In-Line MFL inspections of approximately ninety (90) locations to comply with the baseline assessment and future re-assessment requirements of the Federal Pipeline Safety Improvement Act of 2002

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate

At these one hundred twenty-two (122) locations, one or more cased pipelines could not be inspected using the typical assessment method (External Corrosion Direct Assessment) because the casing(s) rendered the section of pipeline inaccessible. ECDA is categorically ineffective on pipelines that are shielded and can not be physically accessed to perform direct assessment validations. In 32 cases, it has been determined that the casing(s) is/are superfluous because the original conditions that required a cased crossing are no longer present. Therefore, the casing will be excavated and removed to allow direct examination of the carrier pipe to comply with the DOT assessment mandate for baseline

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Capital Improvement / Externally Driven Casing Removals & Tethered Inspections - Blanket	00276.16
WITNESS Ray Stanford	**IN SERVICE DATE** Blanket

assessment and future re-assessment efforts. In 90 cases, it has been determined that one or more casings can be inspected utilizing a tethered in-line MFL inspection tool to comply with the DOT assessment mandate for baseline assessment and future re-assessment efforts.

Forecast Methodology

The majority of the costs to remove a casing or to conduct a tethered inspection are contract labor and equipment charges with very little material required to complete the work. Our estimating methodology is based on historic contractor labor and equipment costs which is distilled down to a cost per day for the anticipated contract resources needed to accomplish the scope of work. In both cases the scope will require a contract crew size of 7 to 8 employees, a backhoe, welder, dump truck, crew truck and various other equipment such as traffic signage, shoring, sand blaster, coating application equipment and so on. A typical daily cost for these resources comes to about $7,700 per day, including all overheads and support costs for the primary contractor. A one time unit cost of between $6,677 and $10,000 is added to cover other contract support services like coating abatement and traffic control, etc.

The estimated duration required to fully complete a casing removal will vary with each site and the length of the casing but should be approximately 15 days. Tethered inspections will also vary. Some will be 25 days or more and will carry the extra cost of the inspection tool vender of $75,000 per casing.

Schedule

The work documented in this work paper will be conducted throughout the time frame of this proceeding. Costs will be recorded annually from 2010 through 12/31/2012.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Replace Line Segments with Manufacturing Defect in Lieu of ILI	00276.17
WITNESS	**IN SERVICE DATE**
Ray Stanford	12/31/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR					553		553
DIRECT NONLABOR					5,950		5,950
TOTAL DIRECT CAPITAL					6,503		6,503
COLLECTIBLE	(0)	(0)	(0)	(0)	(0)	(0)	(0)
NET CAPITAL					6,503		6,503
FTE					6.0		6.0

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

Industry has recognized that low frequency electro-resistance welded (ERW) pipe, which was employed prior to 1970, may affect the integrity of a pipeline due to the quality of the weld seam along the pipe joint.

The presence of this type of seam alone does not present a threat, but in combination with certain operating conditions, the seam threat may become active.

To address this possible threat, the Utilities have identified a group of pipelines that may have been manufactured using this technique and have operating conditions that warrant an assessment using inline liquid medium crack detection tools as part of its normal assessment.

Where it is impractical to use these tools due to single feed situations, or where there are small segments requiring a manufacturing assessment, it may be more economical to replace the segment in lieu of assessment.

In these situations a pipeline may be replaced if it can be completed within the DOT mandated assessment schedule.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Replace Line Segments with Manufacturing Defect in Lieu of ILI	00276.17
WITNESS	**IN SERVICE DATE**
Ray Stanford	12/31/2012

Project Description

Listed below are the pipelines segments identified as having a manufacturing threat that would require replacement.

Pipeline	Segment Length (miles)
30-18	.03
32-60	.04
36-1007	.02
36-37	.17
37-07	.01
37-18	.02
37-18K	.99
41-05	.18
49-16	.09
35-20	6.95
35-20A	.01
36-9-06	.04
36-9-06-A	.02
41-6000-2	.01
41-6501	.02
45-163	.07
Total	8.67

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The replacement length was determined based upon the lineal length of high consequence Transmission pipe that has been identified with an active manufacturing threat but are being planned for replacement in lieu of assessment.

Due to this great variability, a unitized average cost per small replacement projects, a methodology was developed to forecast the expected cost of this work.

Replacement Segment (mile) x Replace Cost Factor = Forecasted Expense

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Replacements / Externally Driven Replace Line Segments with Manufacturing Defect in Lieu of ILI	00276.17
WITNESS	**IN SERVICE DATE**
Ray Stanford	12/31/2012

The replacement factor of $750,000 per mile was based on similar pipeline projects.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects in BC 312 is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

Actual costs for 2009 have also been provided above. Project costs for years 2010 and beyond are forecasted based on the remaining work to be performed. These projections are project specific and have been developed after all needed retrofit was identified and a plan developed, to mitigate all known impediments to traversing an internal inspection device through the pipeline.

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 12/31/2012.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection or replacement.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Capital Improvement / Externally Driven Line SL36-9-09N PI Casing Tether ILI	00276.58
WITNESS Ray Stanford	**IN SERVICE DATE** 05/31/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR					78		78
DIRECT NONLABOR					711		711
TOTAL DIRECT CAPITAL					789		789
COLLECTIBLE					0		0
NET CAPITAL					789		789
FTE					0.8		0.8

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

Conduct tethered In-Line MFL inspection on approximately 970-feet of cased pipeline on Supply Line SL36-9-09N to comply with the baseline assessment and future re-assessment requirements of the Federal Pipeline Safety Improvement Act of 2002. Five separate cased crossings located in Santa Barbara County will be inspected during this effort.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate

These segments of cased pipeline could not be inspected using the appropriate assessment method (External Corrosion Direct Assessment) because the casing rendered the section of pipeline inaccessible. ECDA is categorically ineffective on pipelines that are shielded and can not be physically accessed to perform direct assessment validations. In this case, it has been determined that these casings can be inspected utilizing a tethered in-line MFL inspection tool to comply with the DOT assessment mandate for baseline assessment and future re-assessment efforts.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Capital Improvement / Externally Driven Line SL36-9-09N PI Casing Tether ILI	00276.58
WITNESS	**IN SERVICE DATE**
Ray Stanford	05/31/2012

Forecast Methodology

The majority of the costs to perform a tethered ILI inspection are contract labor and equipment charges with little material required to complete the work. Our estimating methodology is based on historic contractor labor and equipment costs which is distilled down to a cost per day for the anticipated contract resources needed to accomplish the scope of work. This scope will require a contract crew size of 7 to 8 employees, a backhoe, welder, dump truck, crew truck and various other equipment such as traffic signage, shoring, sand blaster, coating application equipment and so on to complete the excavation, fabrication and support the ILI vender. A typical daily cost for these resources comes to about $7,700 per day, including all overheads and support costs for the primary contractor. The ILI vender (Baker Hughes) has provided an all inclusive quote of $75,000 for each casing, to provide and operate the tethered in-line inspection tool. A one time unit cost of $12,000 is added to cover other contract support services like coating abatement and traffic control, etc.

The estimated duration required to fully complete this scope of work is approximately 42 days (42.07202 X $7,700=$323,955 + 5 X $75,000= $375,000 + $12,000= $710,955 Total Non-Labor).

The labor component for this type of work is estimated at about 9% of the non-labor (.092896 X $710,955= $66,045 X 1.1807 V&S Factor= $77,979) and consists of the resources required to research records, planning and design, obtain permits and clearances, manage and coordinate the construction and assessment activities and project documentation and close out functions. An average salary for the classifications needed to carry out these activities is calculated at $82,500. The Company resources required to complete this effort is calculated at .95 of an FTE (Full Time Employee).

Schedule

The capital improvement portion and baseline assessment activities for this project, referred to as the in-service date for this project is: 05/31/2012.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published new rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. Due to limitation of the assessment method selected (in this case ECDA),this segment of cased pipeline is considered a stranded segment where it was left un-assessed at the conclusion of the baseline assessment efforts for the larger segments of Supply Line SL36-9-09N requiring assessment under the rule. These stranded or un-assessed segments are evaluated, an appropriate assessment method determined and then are scheduled for a timeframe commensurate with the risk ranking as well as operational and logistical constraints to be completed in compliance with PSIA 2002.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Capital Improvement / Externally Driven Line SL36-37 PI Casing Tether ILI	00276.60
WITNESS Ray Stanford	**IN SERVICE DATE** 09/30/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				109			109
DIRECT NONLABOR				995			995
TOTAL DIRECT CAPITAL				1,105			1,105
COLLECTIBLE				0			0
NET CAPITAL				1.105			1.105
FTE				1.2			1.2

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

Conduct tethered In-Line MFL inspection on approximately 2,650-feet of cased pipeline on Supply Line SL36-37 to comply with the baseline assessment and future re-assessment requirements of the Federal Pipeline Safety Improvement Act of 2002. Seven cased crossings located in Ventura County will be inspected during this effort.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate

These segments of cased pipeline could not be inspected using the appropriate assessment method (External Corrosion Direct Assessment) because the casing rendered the section of pipeline inaccessible. ECDA is categorically ineffective on pipelines that are shielded and can not be physically accessed to perform direct assessment validations. In this case, it has been determined that these casings can be inspected utilizing a tethered in-line MFL inspection tool to comply with the DOT assessment mandate for baseline assessment and future re-assessment efforts.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Capital Improvement / Externally Driven Line SL36-37 PI Casing Tether ILI	00276.60
WITNESS	**IN SERVICE DATE**
Ray Stanford	09/30/2011

Forecast Methodology

The majority of the costs to perform a tethered ILI inspection are contract labor and equipment charges with little material required to complete the work. Our estimating methodology is based on historic contractor labor and equipment costs which is distilled down to a cost per day for the anticipated contract resources needed to accomplish the scope of work. This scope will require a contract crew size of 7 to 8 employees, a backhoe, welder, dump truck, crew truck and various other equipment such as traffic signage, shoring, sand blaster, coating application equipment and so on to complete the excavation, fabrication and support the ILI vender. A typical daily cost for these resources comes to about $7,700 per day, including all overheads and support costs for the primary contractor. The ILI vender (Baker Hughes) has provided an all inclusive quote of $75,000 for each casing, to provide and operate the tethered in-line inspection tool. A one time unit cost of $16,000 is added to cover other contract support services like coating abatement and traffic control, etc.

The estimated duration required to fully complete this scope of work is approximately 59 days (58.90083 X $7,700=$453,536 + 7 X $75,000 = $525,000 + $16,000= $994,536 Total Non-Labor).

The labor component for this type of work is estimated at about 9% of the non-labor (.092896 X $994,586 = $92,393 X 1.1807 V&S Factor= $109,088) and consists of the resources required to research records, planning and design, obtain permits and clearances, manage and coordinate the construction and assessment activities and project documentation and close out functions. An average salary for the classifications needed to carry out these activities is calculated at $82,500. The Company resources required to complete this effort is calculated at 1.3 of an FTE (Full Time Employee).

Schedule

The capital improvement portion and baseline assessment activities for this project, referred to as the in-service date for this project is: 09/30/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation’s (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published new rule requiring an “integrity management” program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. Due to limitation of the assessment method selected (in this case ECDA),this segment of cased pipeline is considered a stranded segment where it was left un-assessed at the conclusion of the baseline assessment efforts for the larger segments of Supply Line SL36-37 requiring assessment under the rule. These stranded or un-assessed segments are evaluated, an appropriate assessment method determined and then are scheduled for a timeframe commensurate with the risk ranking as well as operational and logistical constraints to be completed in compliance with PSIA 2002.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Capital Improvement / Externally Driven Line SL41-05 PI Casing Tether ILI	00276.71
WITNESS Ray Stanford	**IN SERVICE DATE** 09/30/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR					125		125
DIRECT NONLABOR					1,138		1,138
TOTAL DIRECT CAPITAL					1,262		1,262
COLLECTIBLE					0		0
NET CAPITAL					1,262		1,262
FTE					1.4		1.4

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

Conduct tethered In-Line MFL inspection on approximately 770-feet of cased pipeline on Supply Line SL41-05 to comply with the baseline assessment and future re-assessment requirements of the Federal Pipeline Safety Improvement Act of 2002. Eight separate cased crossings located in San Bernardino County will be inspected during this effort.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate

These segments of cased pipeline could not be inspected using the appropriate assessment method (External Corrosion Direct Assessment) because the casing rendered the section of pipeline inaccessible. ECDA is categorically ineffective on pipelines that are shielded and can not be physically accessed to perform direct assessment validations. In this case, it has been determined that these casings can be inspected utilizing a tethered in-line MFL inspection tool to comply with the DOT assessment mandate for baseline assessment and future re-assessment efforts.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Distribution Pipeline Capital Improvement / Externally Driven Line SL41-05 PI Casing Tether ILI	00276.71
WITNESS	**IN SERVICE DATE**
Ray Stanford	09/30/2012

Forecast Methodology

The majority of the costs to perform a tethered ILI inspection are contract labor and equipment charges with little material required to complete the work. Our estimating methodology is based on historic contractor labor and equipment costs which is distilled down to a cost per day for the anticipated contract resources needed to accomplish the scope of work. This scope will require a contract crew size of 7 to 8 employees, a backhoe, welder, dump truck, crew truck and various other equipment such as traffic signage, shoring, sand blaster, coating application equipment and so on to complete the excavation, fabrication and support the ILI vender. A typical daily cost for these resources comes to about $7,700 per day, including all overheads and support costs for the primary contractor. The ILI vender (Baker Hughes) has provided an all inclusive quote of $75,000 for each casing, to provide and operate the tethered in-line inspection tool. A one time unit cost of $20,000 is added to cover other contract support services like coating abatement and traffic control, etc.

The estimated duration required to fully complete this scope of work is approximately 67 days (67.2114 X $7,700=$517,528 + 8 X $75,000= $600,000 + $20,000= $1,137,528 Total Non-Labor).

The labor component for this type of work is estimated at about 9% of the non-labor (.092896 X $1,137,528= $105,672 X 1.1807 V&S Factor= $124,767) and consists of the resources required to research records, planning and design, obtain permits and clearances, manage and coordinate the construction and assessment activities and project documentation and close out functions. An average salary for the classifications needed to carry out these activities is calculated at $82,500. The Company resources required to complete this effort is calculated at 1.51 of an FTE (Full Time Employee).

Schedule

The capital improvement portion and baseline assessment activities for this project, referred to as the in-service date for this project is: 09/30/2012.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published new rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. Due to limitation of the assessment method selected (in this case ECDA),this segment of cased pipeline is considered a stranded segment where it was left un-assessed at the conclusion of the baseline assessment efforts for the larger segments of Supply Line SL41-05 requiring assessment under the rule. These stranded or un-assessed segments are evaluated, an appropriate assessment method determined and then are scheduled for a timeframe commensurate with the risk ranking as well as operational and logistical constraints to be completed in compliance with PSIA 2002.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Distribution Integrity Management Program (DIMP)	00277.00
WITNESS	**IN SERVICE DATE**
Ray Stanford	Blanket

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				427	907		1,334
DIRECT NONLABOR				13,834	29,317		43,151
TOTAL DIRECT CAPITAL				14,262	30,224		44,486
COLLECTIBLE				0			0
NET CAPITAL				14,262	30,224		44,486
FTE				4.6	9.7		14.3

Business Purpose

On December 4, 2009 the Department of Transportation Pipeline Hazardous Materials and Safety Administration (DOT - PHMSA) published the *Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines; Final Rule*; *49 CFR Part 192 Subpart P*. Under this rule operators of gas distribution systems are required to develop a written integrity management plan that contains procedures for developing and implementing 6 major elements; consisting of (1) System Knowledge, (2) Identify threats, (3) Evaluate and rank risk, (4) Identify and implement measures to address risk, (5) Measure performance, monitor results, and evaluate effectiveness, and (6) Periodic evaluation and improvement. This spending represents pipeline replacement work that is incremental to routine replacement work, and completed to comply with these new DIMP regulatory requirements, as well as achieve Pipeline Integrity risk mitigation goals and objectives.

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.

Physical Description

The program titled **D**istribution **R**isk **E**valuation **A**nd **M**onitoring **S**ystem (**DREAMS**) has been developed to provide the data necessary to address these 6 elements for mains and services within the SoCalGas distribution system, resulting in Main and Service pipe segments in need of replacement to manage the risk of hazardous leaks. that was originally installed using unprotected steel pipe and polyethylene pipe. We refer to “Unprotected Steel” and “PE” pipe made from early generation resins known to have an increased susceptibilty to slow crack growth as non state-of-the-art materials. In addition, this program is applicable to all other PE segments that may leak due to material or installation threats. These two materials make up 73.4% of the SoCalGas buried gas distribution infrastructure mileage.*

*Based on 2009 figures reported to DOT and using the average service length to derive total mileage for services

The scope of the **DREAMS** applications and processes are as follows:

- Holistic, company-wide, standardized approach to segmenting Distribution main piping based on original installation work order, pipe material, and pipe size.
- Dynamic risk ranking algorithms based on known segment information, reported pipe condition, segment-specific leakage history, and known operating conditons. Risk ranking will update as pipe age, condition, and leakage history changes.
- Applicable only to non state-of-the-art mains and services. Non state-of-the-art pipe is defined as:

PROJECT TITLE Distribution Integrity Management Program (DIMP)	BUDGET NO. 00277.00
WITNESS Ray Stanford	IN SERVICE DATE Blanket

- Unprotected Steel (meaning not under cathodic protection)
- PE pipe installed prior to 1985
- Any other PE pipe with a leak history of integrity-relevant leaks

- Associated and complimentary mapping process for identification and tracking of defined Distribution main segments.
- Data scrubbing process used for identifying and clearing conflicting records and data, as well as adding missing, critical data from paper records when needed.
- Data enhancement process usign aerial mapping products for capturing population density, proximity to main, and surface information.
- Associated business processes for managing replacement project planning, generating business reports and metrics.

This spending also includes spending required to mitigate the threat of vehicular damage on facilities located within a 50 ft radius from any corner of a street or highway intersection, or other intersecting transportation pathways intended for routine vehicular traffic. The identified facilities were then reviewed and evaluated for potential risk associated with vehicular impacts causing escaping gas.

Project Justification

So Cal Gas has a long history of continuously improving system integrity management processes in an effort to maintain the safety of the distribution system. Historically the company has managed various system integrity programs and developed risk management models taylored to the needs of the organization based on the system knowledge and operating experience of the day. This work is another step in our efforts to further refine and enhance the way we manage system integrity, and the risks associated with potential leak migration from the buried Distribution piping system.

With unprotected steel and polyethylene materials making up 73.4% of the system mileage for So Cal Gas, a comprehensive and holistic model was desired to ensure consistency of evaluation and relative comparison of operating risks system wide. Continuously improving our integrity managemement tools provide the means to meet new regulatory requirements while taking advantage of GIS technology advancements planned within the organization.

Unprotected Steel System Background

Prior work on the steel system looked at the metallurgy of the various vintages of materials used within the system, along with the various coatings used over the years. This work established a lack of well defined correlations to material families due to the many and varied variables acting upon the system that result in the development of leaks. It also reinforced the practice of focussing on areas where leaks tend to cluster. Economic models were use in the past based on repair vs replacement costs using general corrosion-rate prediction models. However, this approach lacked consideration of specific pipeline condition information and standardization of the overall approach to segmentation of the system. Recent data analysis has established baseline average system performance by decade of Distribution Main inventory providing a performance basis by which individual segments can be measured. This information along with leakage history and reported pipe condition is utilized to identified high-risk segments.

Polyethylene System Background

With over four decades of service from the early polyethylene installations performance data has demonstrated that early polyethylene materials are subject to slow crack growth and require system integrity management to manage leakage risk associated with potential leak migration. PHMSA Advisories ADB-99-01 and ADB-07-01 also reinforce the need for system monitoring of this type.

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WITNESS Ray Stanford	IN SERVICE DATE Blanket

Additional company research has determined that while overall the systems are performing well, the combination of various factors can result in leaks. This research has also demonstrated that the actual in-service age of these plastic systems is not the primary consideration in determining which segments are most likely to leak, similar to it's steel counterpart. Many variables acting upon the distribution system; from variations in the base plastic resin; to design and manufacturing factors; to installation variables; to operating conditions; combine in varying degrees to effect the overall performance of each individual segment within the system. Recent data analysis has established baseline average system performance based on time periods related to significant changes in materials performance, providing a performance basis by which individual segments can be measured. This information along with leakage history and reported pipe condition is utilized to identified high-risk segments. It has also allowed for normalization of risk factors to the performance of the unprotected steel pipe inventory.

Overall System Integrity Management

As system data and knowledge of materials increases from continued research, new insights emerge. Currently there is no cost effective way of determining the many contributing factors impacting the integrity of Distribution systems without first experiencing a leak history or in some cases exposing the pipe. For this reason, recent work has focussed on further analysis of leak history data and data trends. Changing and evolving business systems and operating environments also impact legacy data availability and consistency, presenting a need for data scrubbing and enhancement. These objectives have been achieved through the **DREAMS** business process, culminating in an inventory of Main segments and connected Services that require replacement as part of a cost-effective Pipeline Integrity and risk management strategy.

Vehicular damage has also been identified as a DIMP threat. Work has been conducted to identify facilities located within a 50 ft radius from any corner of a street or highway intersection, or other intersecting transportation pathways intended for routine vehicular traffic. These facilities have been. The identified facilities have been reviewed and evaluated for potential risk associated with vehicular impacts causing severe or incapacitating injury to the vehicle occupant(s) and/or escaping gas, and risk ranked high, medium, or low based operating experience.

Forecast Methodology

Currently the **DREAMS** database has been populated with approximately 12% (2,062 miles) of the estimated 17,193 miles of non-state-of-the-art (NSOTA) main segments in the So Cal Gas Distribution system. When the mains are replaced the services connected to these mains will also be replaced, effectively increasing the total miles of non-state-of-the-art materials removed from the system. Of this inventory that has been assessed through the new DREAMS analysis process, 339 miles of Main have been identified as “high-risk” and qualify for replacement. From this fixed data we project the total inventory of “high-risk” main to be on the order of 1,185 miles (or 6.9% of the total inventory of NSOTA Main). In addition, it is estimated that 25.4 miles of Main will be added to the “high-risk” category annually due to new leakage and continued deterioration of the system over time.

At $119/ Ln ft of Main, the 13.08MM requested for 2011 allows for replacement of approximately 21 miles of qualifying main plus the associated service lines, and the 28.47MM requested for 2012 and subsequent years allows for replacement of approximately 45.3 miles of qualifying main plus the associated service lines.

For the vehicular damage threat the mitigation will be forcast based on the risk ranking of the facilites based on the schedule summarized below.

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Distribution Integrity Management Program (DIMP)	00277.00
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Schedule

Current routine replacement of main will account for approximately 44 miles of Distribution Main replaced annually. With this level of activity it would take over 7 years to replace the current inventory of main already identified for replacement, and 60 years to replace the estimated current total inventory.
As a prudent operator seeking to align with the objectives of the new DIMP regulations, an incremental increase in spend will accelerate this to a more reasonable 20 year program. At this increased rate of replacement the 1,185 mile inventory of “high-risk” Mains and Services, along with the additional miles estimated that will be added to the program annually, will be worked down to a maintenance level (where replacement rate equals rate of deterioration) after approximately 20 years.

For mitigation of the high-risk vehicular damage threat, $590k is required in 2011, broken down as $510k for 340 small meter sets at approximately $1.5k each, and $80k to mitigate 8 above-ground regulator stations at approximately $10k each; $870k will be required in years 2012 through 2015 broken down as $750k for 500 small meter sets at approximately $1.5k each and $120k to mitigate 12 above-ground regulator stations at approximately $10k each.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission – Pipelines - New Additions - Blanket	0311-00
WITNESS	**IN SERVICE DATE**
Ray Stanford	Blanket

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			$10	$0	$178		$188
DIRECT NONLABOR			$205	$0	$5,750		$5,955
TOTAL DIRECT CAPITAL			$215	$0	$5,928		$6,143
COLLECTIBLE			$0		$5,928		$5,928
NET CAPITAL			$215		$0		$215
FTE			0.1	0	1.9		2.0

Business Purpose
This Budget Code includes 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. Includes costs planned in Budget Categories 301, 311, and 321 for "blanket" smaller projects not qualifying for an individual work paper. 2009 recorded costs shown above are for both blanket and specific projects performed in these budget codes.

Physical Description
New pipeline projects include planning, design, permitting, material acquisition, construction, commissioning and impact mitigation for new pipelines and associated valves, fittings, pressure regulating stations and service lines. Projects can range in size and magnitude from a few feet to many miles of large diameter pipeline through urban, suburban, rural or remote terrain within So Cal Gas' service territory.

Individual projects vary from less than $10,000 to as high as multiple hundreds of thousands of dollars

Project Justification
New pipelines are extended to customers in accordance with tariff rules approved by the CPUC. Costs shown on this work paper are based on the average of the most recent five years' recorded expenditures not including collected amounts applied to direct costs. And, as mentioned above in "Business Purpose" this work paper's forecasted years are less any known large project expected to have net recorded costs in excess of 1 million loaded dollars. Those large projects, are shown on separate work papers.

Forecast Methodology
Forecast is shown for 2010 and 2012 only for the following reasons. 2010's amount is for a single smaller project not qualifying for a separate work paper and is thus worked under the "blanket" provision. All other costs for 2010 are based on the 2010 budget and are for several large projects shown on separate work papers. The forecast for 2011 is based on known, specific, projects which are all shown on other work papers. The forecast for 2012 is based on 5 years of recorded history of actual construction in the Budget Categories represented on this work paper.

Schedule
This is a blanket budget.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Anaheim Peaker and MSA Project	00311.01
WITNESS	**IN SERVICE DATE**
Ray Stanford	08/31/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR	10	19	104				133
DIRECT NONLABOR	8	39	2,309				2,356
TOTAL DIRECT CAPITAL	17	58	2,413				2,488
COLLECTIBLE	(17)	(58)	(2,413)				(2,488)
NET CAPITAL	0	0	0				0
FTE	0.1	0.2	1.1	0	0	0	1.4

Business Purpose
This project is required to provide a natural gas pipeline and MSA for the proposed 190 MW Anaheim Peaker electric generating station that will be constructed in Anaheim California.

Physical Description
The project consists of fabricating and installing approximately 3,300-feet of 12-inch nominal diameter pipeline and a complete large GEMS Meter Set Assembly (MSA). The pipeline will be connected to existing 30-inch diameter Pipeline 4000.

Project Justification
This project will initially be 100 percent collectible although the customer may be eligible for refunds depending on recorded gas consumption.

Forecast Methodology
Estimated cost was determined based on the cost to fabricate, install and commission a similarly sized Large GEMS MSA. The estimated cost to install required pipeline, valves and associated appurtenances was based on an analysis of the tasks, material costs provided by suppliers and actual costs for similar work.

Schedule
Engineering and design was started in the 2nd quarter 2009 for the MSA. The project is currently scheduled for completion in the 3rd quarter 2010.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
City of Palmdale UEG Plant	00311-02
WITNESS	**IN SERVICE DATE**
Ray Stanford	06/30/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			59	118	236	0	413
DIRECT NONLABOR			150	10,690	7,510	0	18,350
TOTAL DIRECT CAPITAL			209	10,808	7,746	0	18,763
COLLECTIBLE			0	0	0		0
NET CAPITAL			209	10,808	7,746	0	18,763
FTE			0.6	1.3	2.5	0	4.4

Business Purpose
The City of Palmdale is proposing the installation of a 500 MW electrical generating plant in the City of Palmdale. The project is in the permitting stage through the CEC. The proposed power plant will require gas supply and measurement to fuel the plants generators. The gas facilities serving the new facility will be funded by SCG and placed into rate base.

Physical Description
Design, procure material, construct, test, and start up approximately 7 miles of new 20-inch steel pipeline, Meter Set Assembly and Large GEMS equipment to supply natural gas to new plant. New supply will be connected to existing Line 235 and Line 335 in the Palmdale area near Ave. S and 10th street.

Project Justification
Required to serve new load under CPUC-approved tariffs and customer application.

Forecast Methodology
Forecasted cost estimate developed using historic costs for construction related items and recent price quotes for materials and equipment. Construction costs based upon recent similar pipeline construction costs of similar size pipe installation. MSA and large GEMS equipment estimated using recent quotes and historic actual costs based upon similar completed projects.

Schedule
The customer is currently seeking permit approval through the CEC. The customer has predicted a 1st quarter 2012 first fire date for the plant. Design work is anticipated to begin fourth quarter 2010, material procurement, final design and permitting projected to be completed third quarter 2011 and construction forecasted to begin fourth quarter 2011 and be completed end of 2nd quarter 2012.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
SOCAL EDISON MANDALAY PEAKER UEG PLANT	00311-03
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR	32	17	48	6	0	0	103
DIRECT NONLABOR	331	25	1,450	74	0	0	1,880
TOTAL DIRECT CAPITAL	363	42	1,498	80	0	0	1,983
COLLECTIBLE	(363)	(42)	(1,498)	0	0	0	(1,983)
NET CAPITAL	0	0	0	0	0	0	0
FTE	0.3	0.2	0.5	0.1	0	0	1.1

Business Purpose

This project was requested by the customer, Southern California Edison (SCE), to design, procure and construct a 6” diameter transmission pipeline to supply a 50 MW peaker plant located at the Mandalay power plant in Oxnard. The project costs include the installation of approximately 1,800 feet of 6” diameter line and a meter set assembly unit.

Physical Description

This project consists of design, procure and construct a 1,800 feet of 6” diameter pipeline to supply a 50 MW peaker plant for SCE in the city of Oxnard.

Project Justification

This project is requested by the customer and is expected to be collectible.

Forecast Methodology

SCE contracted with SoCalGas to design, procure and construct 6” and/or 8” line to supply 5 peaker plants. The estimated cost for Mandalay was based on similar project scope from previous peaker projects that SCG had completed.

Schedule

The Mandalay project is currently on hold due to on-going legal issues between SCE and the City of Oxnard but could be complete by as early as February, 2011.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Hydrogen Energy 400 MW Plant	00311-04
WITNESS	**IN SERVICE DATE**
Ray Stanford	09/30/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR	0	0	25	59	118	354	556
DIRECT NONLABOR	0	0	40	250	5,500	8,000	13,790
TOTAL DIRECT CAPITAL	0	0	65	309	5,618	8,354	14,346
COLLECTIBLE			(65)	(309)	(5,618)	(8,354)	(14,346)
NET CAPITAL			0	0	0	0	0
FTE	0	0	0.3	0.6	1.3	3.8	6.0

Business Purpose

Hydrogen Energy is proposing to construct a 400 MW UEG plant near Line 225 in the Coles Levee area near the intersection of Hwy. 119 and Hwy 43. The Plant's primary fuel will be gasified coal and coke. Natural gas will serve as startup and standby fuel, making this project 100% collectible from the customer.

Physical Description

Design, procure material, construct, test and start up approximately 5 miles of new 20-inch pipeline, MSA and GEMS equipment. Project is located in the Bakersfield area north of Hwy. 119 and near Hwy. 43. New supply is proposed to connect to existing Line 225.

Project Justification

Required to serve new load under CPUC-approved tariffs and customer application. Project is 100% collectible from customer.

Forecast Methodology

Forecasted cost estimate developed using historic costs for construction related items and recent price quotes for materials and equipment. Construction costs based upon recent similar pipeline construction costs of similar size pipe installation. MSA and large GEMS equipment estimated using recent quotes and historic actual costs based upon similar completed projects. Customer is starting with a CWA for route study in 2010 to support permitting the project through the CEC.

Schedule

The customer is currently seeking permit approval through the CEC. The customer has predicted a 1st quarter 2015 first fire date for the plant. Route study tentatively scheduled for 2010, design work is anticipated to begin 2011, and estimating material procurement in 2012. Final design and permitting projected to be completed in 2013 and construction forecasted to be completed in 2014. Update form customer is that they are analyzing options for the pipeline routing and environmental issues due to the sensitive Coles Levee area and plan on plant operation in 2015.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
North / South Interconnect - Line 6916	00311-05
WITNESS	**IN SERVICE DATE**
Ray Stanford	09/30/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR	33	399	409	0	0	0	841
DIRECT NONLABOR	85	5,233	4,710	0	0	0	10,028
TOTAL DIRECT CAPITAL	118	5,632	5,119	0	0	0	10,869
COLLECTIBLE	0	0	0	0	0	0	0
NET CAPITAL	118	5,632	5,119	0	0	0	10,869
FTE	0.4	4.3	4.4	0	0	0	9.1

Business Purpose
This project will provide SoCalGas with a systems operating tool for moving up to 80 MMcfd of gas from the northern to the southern system and reduce or eliminate the need to cause additional volumes to be delivered to Blythe during low flow periods.

Physical Description
Repair/recondition and covert to natural gas service approximately 73 miles of the former Questar Southern Trails 16” pipeline between Cabazon and Essex. Construct approximately 1.5 miles of new 16” pipe to connect the existing 16” line into SoCalGas’s Line 3000 near Essex. Construct approximately 1,100 feet of new 16” pipe to connect the existing 16” line into SoCalGas’s Lines 2000, 2001 and 5000 near Cabazon.

Project Justification
SoCalGas’s Energy Markets & Capacity Products department has determined that the ability to transfer 80 MMcfd of gas from SoCalGas’s northern to southern transmission system would provide about $3.3 million per year in benefits in the form of lower Blythe minimum flow supply costs.

Forecast Methodology
The estimating methodology used is a combination of actual costs to-date, balance of bids received for construction work and historic costs used for estimating any unknown costs.

Schedule
The work on the southern segment (approximately 10 miles) of the project is scheduled to be in-service by May 1, 2010. We are still awaiting the Notice to Proceed (NTP) from the BLM for the work on the northern segment (approximately 65 miles) of the project. It is anticipated that the NTP will be received in time to have the entire project operational by Sept. 30, 2010.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Pipeline Integrity Retrofits of Transmission Pipelines - Blanket	00312.00
WITNESS	**IN SERVICE DATE**
Raymond Stanford	Blanket

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			146	303	295		744
DIRECT NONLABOR			1,373	2,796	2,752		6,921
TOTAL DIRECT CAPITAL			1,520	3,099	3,047		7,666
COLLECTIBLE	-	-	-	-	-	-	0
NET CAPITAL			1,520	3,099	3,047		7,666
FTE	.0	.0	1.6	3.3	3.2	.0	8.1

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

This work paper provides for pipeline integrity-related work at 24 sites. Nine sites will involve pipeline retrofits to accommodate “smart pigging”; four sites will involve removal of casings to accommodate carrier pipe inspections; and at eleven sites we will have to employ a tethered inspection tool to go inside existing casings for inspection of the carrier.

Project Description

At nine locations, the pipeline will be altered to accommodate an internal electronic device that traverses the pipeline internally to collect information that is used to assess condition. Many pipelines were not designed to accommodate these inspection tools, and therefore a retrofit is performed where conditions make this work practical. A typical retrofit may include the installation of 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 if needed, repairs.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Pipeline Integrity Retrofits of Transmission Pipelines - Blanket	00312.00
WITNESS	**IN SERVICE DATE**
Raymond Stanford	Blanket

At four locations, casings will be removed to allow access to pipelines for direct inspection where the existing casing is no longer required. This will comply not only with the original baseline assessment but also future re-assessment requirements of the Federal Pipeline Safety Improvement Act of 2002.

At nineteen locations we will conduct tethered In-Line MFL inspections to comply with the baseline assessment and future re-assessment requirements of the Federal Pipeline Safety Improvement Act of 2002

Project Justification

Labor costs are net after application of benefits gained from the OpEx project applicable to Gas Engineering and as stated in the prepared testimony of Richard D. Phillips. The benefits are due to efficiencies gained in asset management and are: for 2010, $34k; for 2011, $47k; and for 2012, $69k.

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using a “retrofit of the pipeline and capital replacement” component, and an “installation of launcher and receiver facilities” component.

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity and experience therewith.

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

For casing removals and tethered inspections, the majority of the costs are contract labor and equipment charges with very little material required to complete the work. Our estimating methodology is based on historic contractor labor and equipment costs which is distilled down to a cost per day for the anticipated contract resources needed to accomplish the scope of work. In both cases the scope will require a contract crew size of 7 to 8 employees, a backhoe, welder, dump truck, crew truck and various other

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
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WITNESS	**IN SERVICE DATE**
Raymond Stanford	Blanket

equipment such as traffic signage, shoring, sand blaster, coating application equipment and so on. A typical daily cost for these resources comes to about $7,700 per day, including all overheads and support costs for the primary contractor. A one time unit cost of between $6,677 and $10,000 is added to cover other contract support services like coating abatement and traffic control, etc.
The estimated duration required to fully complete a casing removal will vary with each site and the length of the casing but should be approximately 15 days. Tethered inspections will also vary. Some will be 25 days or more and will carry the extra cost of the inspection tool vender of $75,000 per casing.

Schedule

The work documented in this work paper will be conducted throughout the time frame of this proceeding. Costs will be recorded annually from 2010 through 12/31/2012.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 156 PI Retrofit	00312.01
WITNESS	**IN SERVICE DATE**
Raymond Stanford	03/31/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			1	68			69
DIRECT NONLABOR			13	618			631
TOTAL DIRECT CAPITAL			14	686			700
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL			14	686			700
FTE	.0	.0	.0	0.7	.0	.0	0.8

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 156. 0

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 156 PI Retrofit	00312.01
WITNESS	IN SERVICE DATE
Raymond Stanford	03/31/2011

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:

1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with

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Gas Transmission Pipeline Replacement/ Externally Driven Line 156 PI Retrofit	00312.01
WITNESS Raymond Stanford	IN SERVICE DATE 03/31/2011

the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the “fixed” component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The “variable” component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

Excavation Component:

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WITNESS	**IN SERVICE DATE**
Raymond Stanford	03/31/2011

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

Based upon the methodology described above, the projected costs for this project by component are:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	7.19	65.53	72.72
Cost of launch/receiver	62.08	565.96	628.03
Capital Sum	**69.26**	**631.49**	**700.75**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 03/31/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an “integrity management” program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the internal inspection device traversing internally through the pipeline. This work is commonly referred to as “retrofitting” the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

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Gas Transmission Pipeline Replacement/ Externally Driven Line 156 PI Retrofit	00312.01
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Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 8107 PI Retrofit	00312.02
WITNESS Raymond Stanford	IN SERVICE DATE 12/31/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			2	70			72
DIRECT NONLABOR			19	642			661
TOTAL DIRECT CAPITAL			21	712			733
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL			21	712			733
FTE	.0	.0	.0	.8	.0	.0	.8

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 8107. Retrofit and complete ILI assessment and repairs of Line 8107. This pipeline is 10” in diameter, 0.85 miles long, has 0.29 miles of HCA and runs

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 8107 PI Retrofit	00312.02
WITNESS	**IN SERVICE DATE**
Raymond Stanford	12/31/2010

from Line 8106 in New Cuyama to Line 8108, valve box number 56, on the east side of Perkins Rd.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:
1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline

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assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

<u>Retrofit and Replacement Component:</u>

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

<u>Launcher – Receiver Component:</u>

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

<u>In-line Inspection Component:</u>

The forecast for the “fixed” component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The “variable” component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

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<u>Excavation Component:</u>

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

<u>Distribution of Labor /Non Labor:</u>

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

Based upon the methodology described above, the projected costs for this project by component are:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	10.42	95.02	105.45
Cost of launch/receiver	62.08	565.96	628.03
Capital Sum	**72.50**	**660.98**	**733.48**

<u>Schedule</u>

The completed capital portion of the project, referred to as in-service date for this project is: 12/31/2010.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the internal inspection device traversing internally through the pipeline. This work is commonly referred to as "retrofitting" the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

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Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

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PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 3002 PI Retrofit	00312.03
WITNESS	**IN SERVICE DATE**
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PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			75				75
DIRECT NONLABOR	9		682				691
TOTAL DIRECT CAPITAL	9		757				766
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL	9		757				766
FTE	.0	.0	.8	.0	.0	.0	.8

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 3002. Retrofit and complete ILI assessment and repairs of Line 3002. This pipeline is 20” in diameter, 0.38 miles long, has 0.38 miles of HCA and runs

PROJECT TITLE Gas Transmission Pipeline Replacement/ Externally Driven Line 3002 PI Retrofit	BUDGET NO. 00312.03
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from Line 3000 at Glenoaks Blvd and Estelle Ave (ID 900-T) in Glendale to Line 765 at Fairmont Ave east of San

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:
1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection

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of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the “fixed” component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The “variable” component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

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Gas Transmission Pipeline Replacement/ Externally Driven Line 3002 PI Retrofit	00312.03
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Excavation Component:

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

In some cases, planning work has commenced upon a particular project and site specific cost estimate has been established for the completion of work. For these projects, the cost forecast is based upon the Work Order Authorization for the project, with an added vacation and sick factor added to labor based upon the year work was incurred or is projected to occur. The projected costs were grouped into categories of work as noted in the table below:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	12.54	134.96	147.50
Cost of launch/receiver	52.58	565.96	618.53
Capital Sum	**65.11**	**700.92**	**766.03**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 05/31/2010.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the

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internal inspection device traversing internally through the pipeline. This work is commonly referred to as “retrofitting” the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 5026 PI Retrofit	00312.04
WITNESS	**IN SERVICE DATE**
Raymond Stanford	04/30/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			4	77			80
DIRECT NONLABOR			33	700			733
TOTAL DIRECT CAPITAL			37	776			813
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL			37	776			813
FTE	.0	.0	.0	.8	.0	.0	.9

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 5026. 0

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PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 5026 PI Retrofit	00312.04
WITNESS	**IN SERVICE DATE**
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Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:

1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with

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the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the “fixed” component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The “variable” component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

Excavation Component:

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WITNESS	**IN SERVICE DATE**
Raymond Stanford	04/30/2011

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

Based upon the methodology described above, the projected costs for this project by component are:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	18.33	167.11	185.44
Cost of launch/receiver	62.08	565.96	628.03
Capital Sum	**80.40**	**733.07**	**813.47**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 04/30/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the internal inspection device traversing internally through the pipeline. This work is commonly referred to as "retrofitting" the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

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Gas Transmission Pipeline Replacement/ Externally Driven Line 5026 PI Retrofit	00312.04
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Raymond Stanford	04/30/2011

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 8106 PI Retrofit	00312.05
WITNESS Raymond Stanford	**IN SERVICE DATE** 04/30/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR	8	4	4	78			94
DIRECT NONLABOR	24	114	37	715			890
TOTAL DIRECT CAPITAL	32	118	41	794			985
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL	32	118	41	794			985
FTE	.1	.0	.0	.9	.0	.0	1.

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 8106. Retrofit and complete ILI assessment and repairs of Line 8106. This pipeline is 8” in diameter, 0.56 miles long, has 0.56 miles of HCA and runs from

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 8106 PI Retrofit	00312.05
WITNESS	**IN SERVICE DATE**
Raymond Stanford	04/30/2011

Line 8107 in New Cuyama to Line 8105, valve number 8106-24.79-0, at Leutholtz Pumping Station.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:
1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline

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Gas Transmission Pipeline Replacement/ Externally Driven Line 8106 PI Retrofit	00312.05
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assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

<u>Retrofit and Replacement Component:</u>

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

<u>Launcher – Receiver Component:</u>

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

<u>In-line Inspection Component:</u>

The forecast for the "fixed" component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The "variable" component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

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Gas Transmission Pipeline Replacement/ Externally Driven Line 8106 PI Retrofit	00312.05
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Excavation Component:

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

In some cases, planning work has commenced upon a particular project and site specific cost estimate has been established for the completion of work. For these projects, the cost forecast is based upon the Work Order Authorization for the project, with an added vacation and sick factor added to labor based upon the year work was incurred or is projected to occur. The projected costs were grouped into categories of work as noted in the table below:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	31.14	335.25	366.40
Cost of launch/receiver	52.58	565.96	618.53
Capital Sum	**83.72**	**901.21**	**984.93**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 04/30/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 8106 PI Retrofit	00312.05
WITNESS	**IN SERVICE DATE**
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internal inspection device traversing internally through the pipeline. This work is commonly referred to as “retrofitting” the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 235 PI Retrofit	00312.06
WITNESS	**IN SERVICE DATE**
Raymond Stanford	04/30/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				4	80		84
DIRECT NONLABOR				41	728		769
TOTAL DIRECT CAPITAL				45	808		853
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL				45	808	808	853
FTE	.0	.0	.0	.0	.9	.0	.9

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 235. 0

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 235 PI Retrofit	00312.06
WITNESS	**IN SERVICE DATE**
Raymond Stanford	04/30/2012

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:

1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with

PROJECT TITLE Gas Transmission Pipeline Replacement/ Externally Driven Line 235 PI Retrofit	BUDGET NO. 00312.06
WITNESS Raymond Stanford	IN SERVICE DATE 04/30/2012

the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

<u>Retrofit and Replacement Component:</u>

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

<u>Launcher – Receiver Component:</u>

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

<u>In-line Inspection Component:</u>

The forecast for the "fixed" component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The "variable" component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

<u>Excavation Component:</u>

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 235 PI Retrofit	00312.06
WITNESS	IN SERVICE DATE
Raymond Stanford	04/30/2012

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

Based upon the methodology described above, the projected costs for this project by component are:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	22.28	203.15	225.43
Cost of launch/receiver	62.08	565.96	628.03
Capital Sum	**84.36**	**769.11**	**853.47**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 04/30/2012.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the internal inspection device traversing internally through the pipeline. This work is commonly referred to as "retrofitting" the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 235 PI Retrofit	00312.06
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Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 85 North PI Retrofit	00312.07
WITNESS Raymond Stanford	**IN SERVICE DATE** 04/30/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			7	91			98
DIRECT NONLABOR			66	831			897
TOTAL DIRECT CAPITAL			73	922			995
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL			73	922			995
FTE	.0	.0	.1	1.	.0	.0	1.1

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 85 North. 0

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 85 North PI Retrofit	00312.07
WITNESS	**IN SERVICE DATE**
Raymond Stanford	04/30/2011

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:
1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with

PROJECT TITLE Gas Transmission Pipeline Replacement/ Externally Driven Line 85 North PI Retrofit	BUDGET NO. 00312.07
WITNESS Raymond Stanford	IN SERVICE DATE 04/30/2011

the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the “fixed” component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The “variable” component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

Excavation Component:

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 85 North PI Retrofit	00312.07
WITNESS	**IN SERVICE DATE**
Raymond Stanford	04/30/2011

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

<u>Distribution of Labor /Non Labor:</u>

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

Based upon the methodology described above, the projected costs for this project by component are:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	36.30	330.94	367.24
Cost of launch/receiver	62.08	565.96	628.03
Capital Sum	**98.37**	**896.90**	**995.27**

<u>Schedule</u>

The completed capital portion of the project, referred to as in-service date for this project is: 04/30/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the internal inspection device traversing internally through the pipeline. This work is commonly referred to as "retrofitting" the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 85 North PI Retrofit	00312.07
WITNESS	**IN SERVICE DATE**
Raymond Stanford	04/30/2011

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 1185 PI Retrofit	00312.08
WITNESS Raymond Stanford	IN SERVICE DATE 08/31/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			110				110
DIRECT NONLABOR			1,005				1,005
TOTAL DIRECT CAPITAL			1,115				1,115
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL			1,115				1,115
FTE	.0	.0	1.1	.0	.0	.0	1.1

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 1185. 0

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 1185 PI Retrofit	00312.08
WITNESS	IN SERVICE DATE
Raymond Stanford	08/31/2010

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:

1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with

PROJECT TITLE Gas Transmission Pipeline Replacement/ Externally Driven Line 1185 PI Retrofit	BUDGET NO. 00312.08
WITNESS Raymond Stanford	IN SERVICE DATE 08/31/2010

the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the "fixed" component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The "variable" component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

Excavation Component:

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 1185 PI Retrofit	00312.08
WITNESS	**IN SERVICE DATE**
Raymond Stanford	08/31/2010

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

Based upon the methodology described above, the projected costs for this project by component are:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	48.16	439.07	487
Cost of launch/receiver	62.08	565.96	628
Capital Sum	**110.23**	**1,005.03**	**1,115**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 08/31/2010.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the internal inspection device traversing internally through the pipeline. This work is commonly referred to as "retrofitting" the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 1185 PI Retrofit	00312.08
WITNESS	**IN SERVICE DATE**
Raymond Stanford	08/31/2010

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 6905 PI Retrofit	00312.09
WITNESS	**IN SERVICE DATE**
Raymond Stanford	09/30/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			110				110
DIRECT NONLABOR			1,001				1,001
TOTAL DIRECT CAPITAL			1,111				1,111
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL			1,111				1,111
FTE	.0	.0	1.2	.0	.0	.0	1.2

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 6905. 0

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 6905 PI Retrofit	00312.09
WITNESS	**IN SERVICE DATE**
Raymond Stanford	09/30/2010

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:

1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with

PROJECT TITLE Gas Transmission Pipeline Replacement/ Externally Driven Line 6905 PI Retrofit	BUDGET NO. 00312.09
WITNESS Raymond Stanford	IN SERVICE DATE 09/30/2010

the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the “fixed” component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The “variable” component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

Excavation Component:

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 6905 PI Retrofit	00312.09
WITNESS	**IN SERVICE DATE**
Raymond Stanford	09/30/2010

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

Based upon the methodology described above, the projected costs for this project by component are:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	47.73	435.14	482
Cost of launch/receiver	62.08	565.96	628
Capital Sum	**109.80**	**1,001.10**	**1,111**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 09/30/2010.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the internal inspection device traversing internally through the pipeline. This work is commonly referred to as "retrofitting" the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 6905 PI Retrofit	00312.09
WITNESS	**IN SERVICE DATE**
Raymond Stanford	09/30/2010

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 235E – Pipeline Integrity	00312.10
WITNESS	**IN SERVICE DATE**
Raymond Stanford	04/30/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR		432		4	142		578
DIRECT NONLABOR		4,248		41	1,294		5,583
TOTAL DIRECT CAPITAL		4,680		45	1,436		6,161
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL		4,680		45	1,436	1,436	6,161
FTE	.0	4.7	.0	.0	1.5	.0	6.3

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 235E. This pipeline is 34” in diameter, 115.15 miles long, has 0.62 miles of HCA and runs from valve number 235-0.00-0 approximately 0.5 miles

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 235E – Pipeline Integrity	00312.10
WITNESS Raymond Stanford	IN SERVICE DATE 04/30/2012

northeast of North Needles Compressor Station to Line 3000 at Newberry Compressor Station (ID 998-T).

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:

1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline

PROJECT TITLE Gas Transmission Pipeline Replacement/ Externally Driven Line 235E – Pipeline Integrity	BUDGET NO. 00312.10
WITNESS Raymond Stanford	IN SERVICE DATE 04/30/2012

assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the “fixed” component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The “variable” component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 235E – Pipeline Integrity	00312.10
WITNESS	**IN SERVICE DATE**
Raymond Stanford	04/30/2012

Excavation Component:

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

In some cases, planning work has commenced upon a particular project and site specific cost estimate has been established for the completion of work. For these projects, the cost forecast is based upon the Work Order Authorization for the project, with an added vacation and sick factor added to labor based upon the year work was incurred or is projected to occur. The projected costs were grouped into categories of work as noted in the table below:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	418.54	4,505.51	4,924
Cost of launch/receiver	105.15	1,131.92	1,237
Capital Sum	**523.69**	**5,637.42**	**6,161**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 04/30/2012.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 235E – Pipeline Integrity	00312.10
WITNESS	**IN SERVICE DATE**
Raymond Stanford	04/30/2012

internal inspection device traversing internally through the pipeline. This work is commonly referred to as "retrofitting" the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 2051 PI Retrofit	00312.11
WITNESS	**IN SERVICE DATE**
Raymond Stanford	10/31/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR		130	147				277
DIRECT NONLABOR		1,024	1,343				2,367
TOTAL DIRECT CAPITAL		1,154	1,490				2,644
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL		1,154	1,490				2,644
FTE	.0	1.4	1.6	.0	.0	.0	3.

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 2051. Retrofit and complete ILI assessment and repairs of Line 2051. This pipeline is 36” in diameter, 44.98 miles long, has 1.98 miles of HCA and runs

PROJECT TITLE Gas Transmission Pipeline Replacement/ Externally Driven Line 2051 PI Retrofit	BUDGET NO. 00312.11
WITNESS Raymond Stanford	IN SERVICE DATE 10/31/2010

from Cactus City Compressor Station (Strip Map 25-39, Strip Map 25-39A) to Whitewater Station (Strip Map 25-2

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:

1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 2051 PI Retrofit	00312.11
WITNESS	**IN SERVICE DATE**
Raymond Stanford	10/31/2010

of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the “fixed” component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The “variable” component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 2051 PI Retrofit	00312.11
WITNESS	IN SERVICE DATE
Raymond Stanford	10/31/2010

Excavation Component:

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

In some cases, planning work has commenced upon a particular project and site specific cost estimate has been established for the completion of work. For these projects, the cost forecast is based upon the Work Order Authorization for the project, with an added vacation and sick factor added to labor based upon the year work was incurred or is projected to occur. The projected costs were grouped into categories of work as noted in the table below:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	172.14	1,852.99	2,025.12
Cost of launch/receiver	52.58	565.96	618.53
Capital Sum	**224.71**	**2,418.94**	**2,643.65**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 10/31/2010.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 2051 PI Retrofit	00312.11
WITNESS	**IN SERVICE DATE**
Raymond Stanford	10/31/2010

internal inspection device traversing internally through the pipeline. This work is commonly referred to as “retrofitting” the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 325 PI Retrofit	00312.12
WITNESS	**IN SERVICE DATE**
Raymond Stanford	06/30/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR		32	154				187
DIRECT NONLABOR		571	1,408				1,979
TOTAL DIRECT CAPITAL		603	1,562				2,165
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL		603	1,562				2,165
FTE	.0	.4	1.7	.0	.0	.0	2.

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 325. Retrofit and complete ILI assessment and repairs of Line 325. This pipeline is 16" & 20” in diameter, 2.15 miles long, has 1.96 miles of HCA and

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 325 PI Retrofit	00312.12
WITNESS	**IN SERVICE DATE**
Raymond Stanford	06/30/2010

runs from Line 765 at Willow Meter Station (ID 562-T) north of Willow St to Line 1176 at Wilmington Ave and Se

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:

1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 325 PI Retrofit	00312.12
WITNESS Raymond Stanford	IN SERVICE DATE 06/30/2010

of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the “fixed” component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The “variable” component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 325 PI Retrofit	00312.12
WITNESS Raymond Stanford	IN SERVICE DATE 06/30/2010

Excavation Component:

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

In some cases, planning work has commenced upon a particular project and site specific cost estimate has been established for the completion of work. For these projects, the cost forecast is based upon the Work Order Authorization for the project, with an added vacation and sick factor added to labor based upon the year work was incurred or is projected to occur. The projected costs were grouped into categories of work as noted in the table below:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	131.49	1,415.41	1,546.90
Cost of launch/receiver	52.58	565.96	618.53
Capital Sum	**184.06**	**1,981.37**	**2,165.43**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is:06/30/2010.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 325 PI Retrofit	00312.12
WITNESS	IN SERVICE DATE
Raymond Stanford	06/30/2010

internal inspection device traversing internally through the pipeline. This work is commonly referred to as "retrofitting" the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 119 North PI Retrofit	00312.13
WITNESS Raymond Stanford	**IN SERVICE DATE** 04/30/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			6	149			155
DIRECT NONLABOR			56	1,355			1,410
TOTAL DIRECT CAPITAL			62	1,503			1,565
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL			62	1,503			1,565
FTE	.0	.0	.1	1.6	.0	.0	1.7

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 119 North. Retrofit and complete ILI assessment and repairs of Line 119 North. This pipeline is 22” in diameter, 16.32 miles long, has 1.10

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 119 North PI Retrofit	00312.13
WITNESS	**IN SERVICE DATE**
Raymond Stanford	04/30/2011

miles of HCA and runs from Line 85 east of Falcon Way and west of Peace Valley Rd to Summit Reservoir.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:

1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection

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PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 119 North PI Retrofit	00312.13
WITNESS	**IN SERVICE DATE**
Raymond Stanford	04/30/2011

of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the "fixed" component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The "variable" component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

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Gas Transmission Pipeline Replacement/ Externally Driven Line 119 North PI Retrofit	00312.13
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Excavation Component:

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

Based upon the methodology described above, the projected costs for this project by component are:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	30.55	278.51	309.06
Cost of launch/receiver	124.15	1,131.92	1,256.07
Capital Sum	**154.70**	**1,410.43**	**1,565.13**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 04/30/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the internal inspection device traversing internally through the pipeline. This work is commonly referred to as "retrofitting" the pipeline.

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PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 119 North PI Retrofit	00312.13
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Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 119 South PI Retrofit	00312.15
WITNESS	**IN SERVICE DATE**
Raymond Stanford	05/31/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			32	189			221
DIRECT NONLABOR			290	1,725			2,014
TOTAL DIRECT CAPITAL			322	1,914			2,236
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL			322	1,914			2,236
FTE	.0	.0	.3	2.0	.0	.0	2.3

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 119 South. 0

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PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 119 South PI Retrofit	00312.15
WITNESS	**IN SERVICE DATE**
Raymond Stanford	05/31/2011

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:

1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with

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Gas Transmission Pipeline Replacement/ Externally Driven Line 119 South PI Retrofit	00312.15
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the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the “fixed” component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The “variable” component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

Excavation Component:

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Gas Transmission Pipeline Replacement/ Externally Driven Line 119 South PI Retrofit	00312.15
WITNESS	**IN SERVICE DATE**
Raymond Stanford	05/31/2011

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

Based upon the methodology described above, the projected costs for this project by component are:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	158.85	1,448.28	1,607.13
Cost of launch/receiver	62.08	565.96	628.03
Capital Sum	**220.93**	**2,014.23**	**2,235.16**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 05/31/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the internal inspection device traversing internally through the pipeline. This work is commonly referred to as "retrofitting" the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

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Gas Transmission Pipeline Replacement/ Externally Driven Line 119 South PI Retrofit	00312.15
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Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 1017 PI Retrofit	00312.16
WITNESS	IN SERVICE DATE
Raymond Stanford	06/30/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR	38	201	324				563
DIRECT NONLABOR	158	2,867	2,952				5,977
TOTAL DIRECT CAPITAL	196	3,069	3,276				6,540
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL	196	3,069	3,276				6,540
FTE	.4	2.2	3.5	.0	.0	.0	6.1

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 1017. Retrofit and complete ILI assessment and repairs of Line 1017. This pipeline is 30” in diameter, 13.97 miles long, has 13.67 miles of HCA and runs

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 1017 PI Retrofit	00312.16
WITNESS	**IN SERVICE DATE**
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from Grand Ave and Chestnut Ave in Santa Ana to AES Huntington Beach Power Plant at Newland and Hamilton.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:

1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 1017 PI Retrofit	00312.16
WITNESS	IN SERVICE DATE
Raymond Stanford	06/30/2010

of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the “fixed” component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The “variable” component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 1017 PI Retrofit	00312.16
WITNESS	IN SERVICE DATE
Raymond Stanford	06/30/2010

Excavation Component:

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

In some cases, planning work has commenced upon a particular project and site specific cost estimate has been established for the completion of work. For these projects, the cost forecast is based upon the Work Order Authorization for the project, with an added vacation and sick factor added to labor based upon the year work was incurred or is projected to occur. The projected costs were grouped into categories of work as noted in the table below:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	503.36	5,418.53	5,921.89
Cost of launch/receiver	52.58	565.96	618.53
Capital Sum	**555.94**	**5,984.48**	**6,540.42**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 06/30/2010.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 1017 PI Retrofit	00312.16
WITNESS	**IN SERVICE DATE**
Raymond Stanford	06/30/2010

internal inspection device traversing internally through the pipeline. This work is commonly referred to as “retrofitting” the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 5000 PI Retrofit	00312.17
WITNESS Raymond Stanford	**IN SERVICE DATE** 11/30/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR		249	458				707
DIRECT NONLABOR		3,382	4,178				7,560
TOTAL DIRECT CAPITAL		3,631	4,636				8,267
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL		3,631	4,636				8,267
FTE	.0	2.7	4.9	.0	.0	.0	7.6

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 5000. Retrofit and complete ILI assessment and repairs of Line 5000. This pipeline is 30" and 36" in diameter, 116.52 miles long, has 15.60 miles of HCA

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 5000 PI Retrofit	00312.17
WITNESS	**IN SERVICE DATE**
Raymond Stanford	11/30/2010

and runs from the center line of the Colorado River span to vale number 20B at Grove Ave and Remington Ave i

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:

1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection

PROJECT TITLE Gas Transmission Pipeline Replacement/ Externally Driven Line 5000 PI Retrofit	BUDGET NO. 00312.17
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of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the "fixed" component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The "variable" component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

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Gas Transmission Pipeline Replacement/ Externally Driven Line 5000 PI Retrofit	00312.17
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Excavation Component:

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

In some cases, planning work has commenced upon a particular project and site specific cost estimate has been established for the completion of work. For these projects, the cost forecast is based upon the Work Order Authorization for the project, with an added vacation and sick factor added to labor based upon the year work was incurred or is projected to occur. The projected costs were grouped into categories of work as noted in the table below:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	650.14	6,998.51	7,648.65
Cost of launch/receiver	52.58	565.96	618.53
Capital Sum	**702.71**	**7,564.47**	**8,267.18**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is:11/30/2010.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 5000 PI Retrofit	00312.17
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internal inspection device traversing internally through the pipeline. This work is commonly referred to as “retrofitting” the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 2001 West PI Retrofit	00312.18
WITNESS	**IN SERVICE DATE**
Raymond Stanford	06/30/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			129	580			709
DIRECT NONLABOR			1,180	5,287			6,467
TOTAL DIRECT CAPITAL			1,310	5,867			7,176
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL			1,310	5,867			7,176
FTE	.0	.0	1.4	6.2	.0	.0	7.6

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 2001 West. 0

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 2001 West PI Retrofit	00312.18
WITNESS	**IN SERVICE DATE**
Raymond Stanford	06/30/2011

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:

1. Retrofit of the pipeline and capital replacement
2. Installation of launcher and receiver facilities
3. In-line inspection
4. Excavations & repairs

Typically the work to complete retrofit, in-line inspection and repair of a pipeline, in order to comply with PSIA 2002, spans more than one year. These projects can be very complicated and must be completed in sequence. Based on experience from projects completed from 2002 -2009, retrofit work needs to start well in advance of the ILI inspection and repair work can continue for multiple years beyond the inspection. As a result all project expenditures are forecast over a three year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Retrofit costs	20%	80%		100%
Cost of launcher/receiver		100%		100%
ILI Fixed		100%		100%
ILI Variable		100%		100%
Validation Digs/Small Repairs		25%	75%	100%

In June of 2005 the Federal Energy Regulatory Commission (FERC) issued an order on accounting for pipeline assessment costs to comply with PSIA 2002 which applied to all FERC jurisdictional operators. The capitalization policy was modified effective January 1, 2008 to reflect the FERC order. The primary impact of the change in capitalization policy is the shifting of in-line inspection and excavations and minor repairs (components 3 & 4 above) from capital to expense. The forecast for these components is shown above as mains maintenance in the O&M workpapers and testimony.

To forecast the cost of this assessment project, the methodology used segregates the costs to complete assessment into a fixed component per planned in-line pipeline(s) and a variable component which is dependent upon the number of miles to be assessed during the run. The fixed component includes the installation of launch receive facilities, the mobilization and demobilization of in-line inspection vendors, and four (4) verification excavations per in-line inspection run. The variable component includes the costs to retrofit the pipeline (i.e. replace main line valves, install barred tees, and complete capital replacement to address pipeline not fit for service) and an incremental cost to in-line inspection vendors for inspection of a great number of miles of pipeline. To develop the cost to apply to the forecast activity in the baseline assessment plan, the adjusted recorded costs for this activity and the number of in-line inspection pipelines and the miles of high consequence area (HCA) pipeline assessed were used in conjunction with

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WITNESS Raymond Stanford	IN SERVICE DATE 06/30/2011

the costs to perform in-line inspection and perform excavations as follows (recorded data is from BC 312 which captures this activity).

Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the “fixed” component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The “variable” component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

Excavation Component:

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Gas Transmission Pipeline Replacement/ Externally Driven Line 2001 West PI Retrofit	00312.18
WITNESS	**IN SERVICE DATE**
Raymond Stanford	06/30/2011

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

Based upon the methodology described above, the projected costs for this project by component are:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	647.26	5,901.24	6,548.50
Cost of launch/receiver	62.08	565.96	628.03
Capital Sum	**709.34**	**6,467.19**	**7,176.53**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 06/30/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the internal inspection device traversing internally through the pipeline. This work is commonly referred to as "retrofitting" the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

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Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 3000 PI Retrofit	00312.19
WITNESS Raymond Stanford	IN SERVICE DATE 01/31/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR	66	5	1,186	89			1,345
DIRECT NONLABOR	599		10,810	814			12,222
TOTAL DIRECT CAPITAL	664	5	11,996	903			13,568
COLLECTIBLE	-	-	-	-	-	-	-
NET CAPITAL	664	5	11,996	903			13,568
FTE	.7	.1	12.7	1.0	.0	.0	14.5

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

An inspection of the pipeline will be performed using an internal electronic device that will traverse internally along the route of the pipeline to collect information that will be used to assess the pipeline. The pipeline was not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow for sufficient clearance for the tool during inspection. A typical retrofit may include the installation of 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 will be run, followed by excavations to validate the inspection findings and if needed, repairs. Should it be more economical, a pipeline may be replaced or altered in lieu of retrofitting for internal inspection, 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.

Project Description

Retrofit and complete ILI assessment and repairs of Line 3000. Retrofit and complete ILI assessment and repairs of Line 3000. This pipeline is 30” and 34" in diameter, 169.02 miles long, has 40.85 miles of HCA

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 3000 PI Retrofit	00312.19
WITNESS	**IN SERVICE DATE**
Raymond Stanford	01/31/2011

and runs from the center line of the Colorado River span to the Alhambra Station at Mission Rd and Marengo A

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The Capital forecast to retrofit and assess a pipeline is forecast using the following four components:

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4. Excavations & repairs

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Retrofit and Replacement Component:

The retrofit component is pipeline specific and varies greatly dependent upon the unique features of the pipeline. A pipeline may have been constructed with many or very few fittings that need to be replaced, and can not be readily applied pipeline to pipeline in the same manner that launcher and receiver facilities are. In addition, the assessment results may indicate the pipeline is fit for service, or may indicate that miles of pipeline need to be replaced. Finally, in lieu of retrofitting a pipeline, due to factors associated with the construction methods and materials of the pipeline and other properties it may be more practical and cost effective to replace a pipeline rather than assess the line. Although great variation of exists, this activity is forecast using the scheduled number of pipeline runs and is applied to the normalized cost per pipeline run for the recorded costs 2003 through 2009. This is the period since the PSIA was passed resulting in a dramatic increase in the level of activity.

Costs for retrofit and replacement forecasts are calculated using the cost per HCA mile based component factor.

The cost per HCA mile factor is calculated based on actual ILI projects completed from 2003 thru 2009. Using total capital costs reduced by a launcher and receiver component, a unitized average cost of $358,103 per HCA mile was calculated. This figure multiplied by the project specific HCA miles was used to determine retrofit and replacement forecasts for the project.

Launcher – Receiver Component:

The launcher and receiver component of retrofit work is specific to pipeline inspection runs, not the number of miles of pipeline. The number of inspection runs, and the cost to complete this component is based upon the lowest awarded bid for installation and launch/receiver materials of a typical project plus a factor for site specific expenses, radiography and equipment expenses. With the Company labor allocation, the launcher/receiver forecast is $309,267 ($282,979/0.915) per site. Assuming a launcher and a receiver is required, a total expense of $618,533 per run and the launcher-receiver component was calculated as the number of runs x $618,533.

In-line Inspection Component:

The forecast for the “fixed” component is forecast based upon the lowest bid from a Request For Proposal (RFP) in 2010. To set the fixed component of the ILI inspection, the 8.5% average labor component was applied to the lowest bid ($54,497) resulting in a fixed ILI component of $59,129 per ILI project. The “variable” component is calculated by totaling the cost of the 6 awarded bids ($688,029) subtracting the fixed component without company labor (6 X $54,497 = $326,982) for a total variable cost of $361,047 including an 8.5% company labor component. The variable component was normalized by the total HCA miles (179) for a variable cost per HCA mile of $2,203. The ILI cost component was calculated as (number Miles HCA) x $2,203 (or the normalized HCA miles from 2010 bids) plus the ILI fixed component $59,129 per project from 2010 RFP.

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PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 3000 PI Retrofit	00312.19
WITNESS	**IN SERVICE DATE**
Raymond Stanford	01/31/2011

Excavation Component:

To forecast the excavation component of the assessments, it is assumed that there will be 4 excavations per ILI run. The cost per excavation is forecast to be $50,000 and is based upon a typical excavation completed in 2009. The result is a cost of $200,000 per run. The excavation component was therefore calculated as number of runs x $200,000.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

In some cases, planning work has commenced upon a particular project and site specific cost estimate has been established for the completion of work. For these projects, the cost forecast is based upon the Work Order Authorization for the project, with an added vacation and sick factor added to labor based upon the year work was incurred or is projected to occur. The projected costs were grouped into categories of work as noted in the table below:

Component ($000 in 2009$)	**Labor**	**Non-Labor**	**Projected Cost**
Retrofit costs	1,048.11	11,282.55	12,330.66
Cost of launch/receiver	105.15	1,131.92	1,237.07
Capital Sum	**1,153.26**	**12,414.47**	**13,567.72**

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 01/31/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for retrofitting the pipeline is initiated. A detailed study of the pipeline components is created. A plan is developed to remove all identified impediments to the

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacement/ Externally Driven Line 3000 PI Retrofit	00312.19
WITNESS	**IN SERVICE DATE**
Raymond Stanford	01/31/2011

internal inspection device traversing internally through the pipeline. This work is commonly referred to as “retrofitting” the pipeline.

Year 2: The majority of retrofit work is implemented, launcher and receivers are installed and the pipeline is assessed. The vendor data is received and analyzed and any DOT mandated repairs are made.

Year 3: A series of validation excavations are performed to verify the accuracy of the data. Final follow-up of the validation process along with any remedial measures is completed.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven Replace Line Segments Containing Wrinkle Bends	00312.21
WITNESS	IN SERVICE DATE
Ray Stanford	12/31/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				673	1,347		2,020
DIRECT NONLABOR				7,420	14,503		21,743
TOTAL DIRECT CAPITAL				7,913	15,850		23,763
COLLECTIBLE	(0)	(0)	(0)	(0)	(0)	(0)	(0)
NET CAPITAL				7,913	15,850		23,763
FTE				7.3	14.6		21.9

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

Prior to the early 1970s, there was an accepted industry practice to make permanent field bends in pipelines during construction to make small adjustments to accommodate various terrain and changes in the right of way. This process when employed, would create one or more wrinkles on the inside radius of a field bend.

Industry research has found that these bends are typically not a threat to the integrity of a pipeline under stable loading conditions. However, Industry and the Regulatory entities have recognized that these types of bends can be subject to failure due to changes in loading stresses caused by excavation or by external forces placed upon the wrinkle bend. These forces are typically caused by changes to the ground constraint surrounding the wrinkle bend.

As such, the Utility has established a program to identify field bends that are located in a high consequence area that potentially are subject to a known outside force hazard.

These hazards include, but are not limited to, bends located near a seismic fault crossing per the California Geological Survey (CGS) under the Alquist-Priolo Act and bends located in an identified landslide zone and on sloped terrain within identified liquefaction areas per the Seismic Hazard Mapping Act which was established in 1990.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven Replace Line Segments Containing Wrinkle Bends	00312.21
WITNESS	**IN SERVICE DATE**
Ray Stanford	12/31/2012

The decision to remove or reinforce the field constructed bends with a full encirclement canopy was based upon the lack of tools and assessment techniques available to assess this type of pipeline threat.

Project Description

The following pipelines listed in the table below have been identified as having field bends suspected of having one or more wrinkles based upon inline inspection data and historical record searches.

The project will indentify all field bends located in the length of pipeline located in proximity to a known hazard. Field bends that are determined to have one or more wrinkles will be repaired or removed to address potential failures caused by ground movement.

Pipeline	Pipeline Length to be Mitigated in Proximity to an Outside Force Hazard (miles)	Projected Cost to Mitigate ($000)
1028	1.3	479
1180	1.8	632
2000	.4	137
2000 W	3.1	1,104
2002	2.4	861
2003	27	9,667
4000	10.2	3,653
4002	7.6	2,729
404	5.4	1,945
406	1.5	544
5000(3)*	(.6)*	(207)*
7039	1.2	431
8109	5.0	1,788
Total	**66.4**	**23,763***
Correct Total	**67.5**	**24,176**

Note: Line 5000(3) was inadvertently submitted with a negative stationing value which created a credit of $207K. In actuality, the projected cost for 5000(3) should be $207K, which creates a positive shift in the total cost of the project by $413K.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The mitigation length was determined based upon the lineal length of high consequence Transmission pipe located within a hazard zone and are suspected as having one or more bends that may contain a

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven Replace Line Segments Containing Wrinkle Bends	00312.21
WITNESS	**IN SERVICE DATE**
Ray Stanford	12/31/2012

wrinkle per historical records searches and inner diameter geometry data obtained from prior inline assessment.

The number of field bends located within hazard zone varies greatly and is dependent upon the unique features of the right of way of the pipeline. Furthermore, a pipeline may have been constructed with a combination of field bends that may or may not contain an inner bend surface that has been strained sufficiently to cause a wrinkle.

Due to this great variability, a unitized average cost per mitigation length methodology was developed to forecast the expected cost of this work.

Mitigation Length (mile) x Mitigation Factor = Forecasted Expense

The mitigation factor was based on actual capital costs incurred between 2003- 2009 to retrofit pipelines for inline inspection. Using the total capital costs reduced by a launcher and receiver component for a completed ILI project, a unitized average cost of $358,103 per mile was calculated for retrofitting a length of pipe.

This retrofit average cost is based upon the removal or repair of pipe appurtenances that impede the progress of an inspection tool along a unitized length of pipe. This factor is similar in nature to the removal or reinforcement of indentified field bends upon a unitized mitigation length being employed for this project.

Distribution of Labor /Non Labor:

The majority of work required to accomplish this project is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future projects scheduled in 2010-2012.

Schedule

This individual pipeline mitigation projects are expected to begin in 2011 and are scheduled to be completed by: 12/31/2012.

The initial assessment or mitigation of all non-assessment type threats for all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a required component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven Multiple Small Replacement Projects in Lieu of ILI	00312.22
WITNESS	**IN SERVICE DATE**
Ray Stanford	03/31/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			14	8	5		27
DIRECT NONLABOR			584	1,166	527		2,277
TOTAL DIRECT CAPITAL			598	1,174	532		2,304
COLLECTIBLE	(0)	(0)	(0)	(0)	(0)	(0)	(0)
NET CAPITAL			598	1,174	532		2,304
FTE			0.2	0.1	0.1		0.4

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

In certain situations due to the pipe condition, location or environment it may be more economical to replace a pipeline with new pipe operating at lower stress which would not require baseline assessment or repeated re-assessment. This is often the case with short pipe segments and cross over piping. In those situations a pipeline may be replaced in lieu of retrofitting for internal inspection, if the construction can be implemented within the DOT mandated assessment schedule. Alternatively for some longer pipelines pressure reducing facilities (regulation station) may be installed to operate the pipeline at lower pressure and stress levels in lieu of repeated inspection per PSIA 2002.

Project Description

Type	Line Number	Year
Replacement	1234	2010
Regulator Station	1129	2011
Replacement	1221	2012
Replacement	2007	2012
Replacement	5041	2010
Replacement	1031	2010
Replacement	1003	2011

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven Multiple Small Replacement Projects in Lieu of ILI	00312.22
WITNESS	**IN SERVICE DATE**
Ray Stanford	03/31/2012

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

Cost forecasts are based on completed work from similar projects involving similar pipeline replacement and facility installation.

Often the work to complete replacement of a pipeline, in order to comply with PSIA 2002, spans more than one year. Based on experience with previous pipeline replacements, project expenditures are forecast over a two year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Pipeline section replacement	75%	25%		100%

Schedule
The completed capital portion of the project, referred to as in-service date for this project is: 03/31/2012.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for replacement. A detailed study of the pipeline components is created. A plan is developed to remove/replace all identified sections of the pipeline. Permits are acquired, Materials are ordered and the job is awarded for construction to a contractor. Construction is started and completed depending on size and duration of job.

Year 2: When construction spans more than one year the remaining work is completed and pipeline is placed in service.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven L103 Pipeline Replacement in Lieu of ILI	00312.23
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			21	6			27
DIRECT NONLABOR			882	294			1,176
TOTAL DIRECT CAPITAL			903	300			1,203
COLLECTIBLE	(0)	(0)	(0)	(0)		(0)	(0)
NET CAPITAL			903	300			1,203
FTE			0.2	0.1			0.3

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

In certain situations due to the pipe condition, location or environment it may be more economical to replace a pipeline with new pipe operating at lower stress which would not require baseline assessment or repeated re-assessment. This is often the case with short pipe segments and cross over piping. In those situations a pipeline may be replaced in lieu of retrofitting for internal inspection, if the construction can be implemented within the DOT mandated assessment schedule. Alternatively for some longer pipelines pressure reducing facilities (regulation station) may be installed to operate the pipeline at lower pressure and stress levels in lieu of repeated inspection per PSIA 2002.

Project Description

Replace 2,100 feet of 10” pipe on Transmission L103, east of Tupman rd., near Tupman, California Tupman.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven L103 Pipeline Replacement in Lieu of ILI	00312.23
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2011

Forecast Methodology

Cost forecasts are based on completed work from similar projects involving similar pipeline replacement and facility installation.

Often the work to complete replacement of a pipeline, in order to comply with PSIA 2002, spans more than one year. Based on experience with previous pipeline replacements, project expenditures are forecast over a two year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Pipeline section replacement	75%	25%		100%

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 01/31/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for replacement. A detailed study of the pipeline components is created. A plan is developed to remove/replace all identified sections of the pipeline. Permits are acquired, Materials are ordered and the job is awarded for construction to a contractor. Construction is started and completed depending on size and duration of job.

Year 2: When construction spans more than one year the remaining work is completed and pipeline is placed in service.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven L 307 Alteration and Pressure Reduction in Lieu of ILI	00312.24
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				11	4		15
DIRECT NONLABOR				515	172		687
TOTAL DIRECT CAPITAL				526	176		702
COLLECTIBLE	(0)	(0)	(0)	(0)	(0)	(0)	(0)
NET CAPITAL				526	176		702
FTE				0.1	0.1		0.2

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

In certain situations due to the pipe condition, location or environment it may be more economical to replace a pipeline with new pipe operating at lower stress which would not require baseline assessment or repeated re-assessment. This is often the case with short pipe segments and cross over piping. In those situations a pipeline may be replaced in lieu of retrofitting for internal inspection, if the construction can be implemented within the DOT mandated assessment schedule. Alternatively for some longer pipelines pressure reducing facilities (regulation station) may be installed to operate the pipeline at lower pressure and stress levels in lieu of repeated inspection per PSIA 2002.

Project Description

Install Transmission pressure reduction station, remove 24" MLV and replace 500 feet of 24" pipe on Transmission Line 307, at Junction L30" 2002, Montebello, California.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven L 307 Alteration and Pressure Reduction in Lieu of ILI	00312.24
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2012

Forecast Methodology

Cost forecasts are based on completed work from similar projects involving similar pipeline replacement and facility installation.

Often the work to complete replacement of a pipeline, in order to comply with PSIA 2002, spans more than one year. Based on experience with previous pipeline replacements, project expenditures are forecast over a two year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Install Pressure reduction facilities with short pipe section replacement	75%	25%		100%

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 01/31/2012.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for replacement. A detailed study of the pipeline components is created. A plan is developed to remove/replace all identified sections of the pipeline. Permits are acquired, Materials are ordered and the job is awarded for construction to a contractor. Construction is started and completed depending on size and duration of job.

Year 2: When construction spans more than one year the remaining work is completed and pipeline is placed in service.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven L8109 Pressure Reduction in Lieu of ILI	00312.26
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			21	6			27
DIRECT NONLABOR			882	294			1,176
TOTAL DIRECT CAPITAL			903	300			1,203
COLLECTIBLE	(0)	(0)	(0)	(0)		(0)	(0)
NET CAPITAL			903	300			1,203
FTE			0.2	0.1			0.3

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

In certain situations due to the pipe condition, location or environment it may be more economical to replace a pipeline with new pipe operating at lower stress which would not require baseline assessment or repeated re-assessment. This is often the case with short pipe segments and cross over piping. In those situations a pipeline may be replaced in lieu of retrofitting for internal inspection, if the construction can be implemented within the DOT mandated assessment schedule. Alternatively for some longer pipelines pressure reducing facilities (regulation station) may be installed to operate the pipeline at lower pressure and stress levels in lieu of repeated inspection per PSIA 2002.

Project Description

Install Transmission pressure reduction station and replace 1000 feet of 20" pipe, at Live Oak MLV site, north of Lake Casitas, California.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven L8109 Pressure Reduction in Lieu of ILI	00312.26
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2011

Forecast Methodology

Cost forecasts are based on completed work from similar projects involving similar pipeline replacement and facility installation.

Often the work to complete replacement of a pipeline, in order to comply with PSIA 2002, spans more than one year. Based on experience with previous pipeline replacements, project expenditures are forecast over a two year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Install Pressure reduction facilities with short pipe section replacement	75%	25%		100%

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 01/31/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for replacement. A detailed study of the pipeline components is created. A plan is developed to remove/replace all identified sections of the pipeline. Permits are acquired, Materials are ordered and the job is awarded for construction to a contractor. Construction is started and completed depending on size and duration of job.

Year 2: When construction spans more than one year the remaining work is completed and pipeline is placed in service.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven L1171 Pressure Reduction in Lieu of ILI	00312.27
WITNESS Ray Stanford	**IN SERVICE DATE** 02/28/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			57	16			73
DIRECT NONLABOR			2,352	784			3,136
TOTAL DIRECT CAPITAL			2,409	800			3,209
COLLECTIBLE	(0)	(0)	(0)	(0)		(0)	(0)
NET CAPITAL			2,409	800			3,209
FTE			0.6	0.2			0.8

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

In certain situations due to the pipe condition, location or environment it may be more economical to replace a pipeline with new pipe operating at lower stress which would not require baseline assessment or repeated re-assessment. This is often the case with short pipe segments and cross over piping. In those situations a pipeline may be replaced in lieu of retrofitting for internal inspection, if the construction can be implemented within the DOT mandated assessment schedule. Alternatively for some longer pipelines pressure reducing facilities (regulation station) may be installed to operate the pipeline at lower pressure and stress levels in lieu of repeated inspection per PSIA 2002.

Project Description

Abandon existing MLV station, Install new Transmission pressure reduction station, and replace 1,500 feet of 30" pipe on L1171 at 190th & Green Ln, El Segundo, California.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven L1171 Pressure Reduction in Lieu of ILI	00312.27
WITNESS	**IN SERVICE DATE**
Ray Stanford	02/28/2011

Forecast Methodology

Cost forecasts are based on completed work from similar projects involving similar pipeline replacement and facility installation.

Often the work to complete replacement of a pipeline, in order to comply with PSIA 2002, spans more than one year. Based on experience with previous pipeline replacements, project expenditures are forecast over a two year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Install Pressure reduction facilities with short pipe section replacement	75%	25%		100%

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 02/28/2011. The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for replacement. A detailed study of the pipeline components is created. A plan is developed to remove/replace all identified sections of the pipeline. Permits are acquired, Materials are ordered and the job is awarded for construction to a contractor. Construction is started and completed depending on size and duration of job.

Year 2: When construction spans more than one year the remaining work is completed and pipeline is placed in service.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven Line 317 Replacement 2.17 Miles of 12" Pipe in Lieu of ILI	00312.28
WITNESS Ray Stanford	**IN SERVICE DATE** 01/31/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			16	4			20
DIRECT NONLABOR			742	247			989
TOTAL DIRECT CAPITAL			758	251			1,009
COLLECTIBLE	(0)	(0)	(0)	(0)		(0)	(0)
NET CAPITAL			758	251			1,009
FTE			0.2	0.1			0.3

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

In certain situations due to the pipe condition, location or environment it may be more economical to replace a pipeline with new pipe operating at lower stress which would not require baseline assessment or repeated re-assessment. This is often the case with short pipe segments and cross over piping. In those situations a pipeline may be replaced in lieu of retrofitting for internal inspection, if the construction can be implemented within the DOT mandated assessment schedule. Alternatively for some longer pipelines pressure reducing facilities (regulation station) may be installed to operate the pipeline at lower pressure and stress levels in lieu of repeated inspection per PSIA 2002.

Project Description

Replace 2.17 miles of 12" pipe on Transmission L317, from Producer Plains Exploration in Los Angeles, to Line 1242 at Playa St and Hannum Ave in Culver City.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven Line 317 Replacement 2.17 Miles of 12" Pipe in Lieu of ILI	00312.28
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2011

Forecast Methodology

Cost forecasts are based on completed work from similar projects involving similar pipeline replacement and facility installation.

Often the work to complete replacement of a pipeline, in order to comply with PSIA 2002, spans more than one year. Based on experience with previous pipeline replacements, project expenditures are forecast over a two year period.

Typical Schedule	Year 1 % Work	Year 2 % Work	Year 3 % Work	Sum
Pipeline section replacement	75%	25%		100%

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 01/31/2011.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for replacement. A detailed study of the pipeline components is created. A plan is developed to remove/replace all identified sections of the pipeline. Permits are acquired, Materials are ordered and the job is awarded for construction to a contractor. Construction is started and completed depending on size and duration of job.

Year 2: When construction spans more than one year the remaining work is completed and pipeline is placed in service.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE Gas Transmission Pipeline Replacements / Externally Driven Replace Line Segments with Manufacturing Defect in Lieu of ILI	BUDGET NO. 00312.30
WITNESS Ray Stanford	IN SERVICE DATE 12/31/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR					95		95
DIRECT NONLABOR					1,023		1,023
TOTAL DIRECT CAPITAL					1,118		1,118
COLLECTIBLE	(0)	(0)	(0)	(0)	(0)	(0)	(0)
NET CAPITAL					1,118		1,118
FTE					1.0		1.0

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

Industry has recognized that low frequency electro-resistance welded (ERW) pipe, which was employed prior to 1970, may affect the integrity of a pipeline due to the quality of the weld seam along the pipe joint.

The presence of this type of seam alone does not present a threat, but in combination with certain operating conditions, the seam threat may become active.

To address this possible threat, the Utilities have identified a group of pipelines that may have been manufactured using this technique and have operating conditions that warrant an assessment using inline liquid medium crack detection tools as part of its normal assessment.

Where it is impractical to use these tools due to single feed situations, or where there are small segments requiring a manufacturing assessment, it may be more economical to replace the segment in lieu of assessment.

In these situations a pipeline may be replaced if it can be completed within the DOT mandated assessment schedule.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven Replace Line Segments with Manufacturing Defect in Lieu of ILI	00312.30
WITNESS	**IN SERVICE DATE**
Ray Stanford	12/31/2012

Project Description

Listed below are the pipelines segments identified as having a manufacturing threat that would require replacement.

Pipeline	Segment Length (miles)
1027	.01
1600	.42
1601	.12
1604	.11
2000	.30
1011	.01
1171	.04
1172	.25
1173	.01
1202	.02
2006	.10
2007	.02
293	.01
7000	.01
765	.05
8045	.01
Total	1.49

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate.

Forecast Methodology

The replacement length was determined based upon the lineal length of high consequence Transmission pipe that has been identified with an active manufacturing threat but are being planned for replacement in lieu of assessment.

Due to this great variability, a unitized average cost per small replacement projects, a methodology was developed to forecast the expected cost of this work.

Replacement Segment (mile) x Replace Cost Factor = Forecasted Expense

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven Replace Line Segments with Manufacturing Defect in Lieu of ILI	00312.30
WITNESS	**IN SERVICE DATE**
Ray Stanford	12/31/2012

The replacement factor of $750,000 per mile was based similar pipeline projects.

Distribution of Labor /Non Labor:

The majority of work required to accomplish in projects in BC 312 is contractor work and materials which is pooled into the non-labor category. Based upon projects completed from 2003-2009, the labor/non-labor split is 8.5% and 91.5%, respectively. This split was used to forecast future in 2010-2012.

Actual costs for 2009 have also been provided above. Project costs for years 2010 and beyond are forecasted based on the remaining work to be performed. These projections are project specific and have been developed after all needed retrofit was identified and a plan developed, to mitigate all known impediments to traversing an internal inspection device through the pipeline.

Schedule

The completed capital portion of the project, referred to as in-service date for this project is: 12/31/2012.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection or replacement.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Line 6000 Alamo River HDD Relocation Project	00312.31
WITNESS	**IN SERVICE DATE**
Ray Stanford	07/31/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR	0	21	63	0	0	0	84
DIRECT NONLABOR	0	102	307	0	0	0	409
TOTAL DIRECT CAPITAL	0	123	370	0	0	0	493
COLLECTIBLE	0	0	0	0	0	0	0
NET CAPITAL	0	123	370	0	0	0	493
FTE	0	0.2	0.7	0	0	0	0.9

Business Purpose
This project relocates a portion of an existing gas transmission pipeline (Line 6000), which spans over the Alamo River at Kershaw Road near Calipatria in Imperial Valley, California. The pipeline runs parallel to Kershaw Road up to the river's bank; where it coverts to two (2) spans that form an arch above the Alamo River. The spans have wrinkle bends and are required to be replaced in order to comply with established state and federal pipeline safety codes and regulations.

Physical Description
The spans will be replaced by approximately 690 linear feet of new 10-inch diameter high pressure pipeline. The new pipe will be installed underneath the Alamo River through Horizontal Directional Drilling (HDD) construction methodology. When installation is completed, the new pipe will be connected to existing pipeline and the spans will be cut and removed. Approximately 500 linear feet of existing pipe between the tie-in points will be abandoned in place.

Project Justification
The existing pipeline spans are in conflict with current state and federal safety codes and regulations. The new pipe that will replace the spans is designed to provide added safety with increased wall thickness and higher grade quality. Design parameters used to determine the specifications are based on engineering methodology for installation of pipelines by horizontal directional drilling. The project is expected to increase the safety and reliability of the existing system while contributing to savings by reducing the operation and maintenance costs.

Forecast Methodology
Project cost estimate was prepared with information provided by a pipeline contractor for budgetary purpose. Other direct costs are based on a recently completed project with similar scope of work at the same location.

Schedule
Construction work is expected to begin in May 2010 and conclude by July 31, 2010.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements Sullivan Canyon Pipeline Exposure repair Lines 407 & 3003	00312.32
WITNESS Ray Stanford	IN SERVICE DATE 02/28/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			590	885	89		1,564
DIRECT NONLABOR			2,500	1,250	425		4,175
TOTAL DIRECT CAPITAL			3,090	2,136	514		5,740
COLLECTIBLE			0	0	0	0	0
NET CAPITAL			3,090	2,136	514		5,740
FTE			6.3	9.5	1.0		16.8

Business Purpose

Pipelines 407 and 3003 run through the Sullivan canyon and are 30-inch and 34-inch high pressure natural gas transmission pipelines respectively. SoCalGas proposes to reestablish the access road and repair 22 existing pipeline exposures that are mostly a result from flood flows from large storm events and repair future pipeline exposures that result from flood flows from storm events.

Physical Description

The Sullivan Canyon project area includes the approximately 4.5 mile reach from San Vicente Mountain to the Los Angeles County debris basin near Queensferry Road in the Brentwood area of the City of Los Angeles. The approximately 1,523 acre (2.38 square miles) watershed runs from a 1,960-foot elevation to a 570-foot elevation at the debris basin. This project consists of reestablishing that access road and repairing 22 existing pipeline exposures and future pipeline exposures. Work activity to repair exposed pipelines involves excavating a section of exposed pipeline to inspect for damage, repairing the pipe wrap, and installing pipeline protection structures including articulated concrete mats and ungrouted riprap bank protection that will provide for the protection of exposed pipelines in water ways while maintaining creek flows and facilitating the establishment of native riparian vegetation. Implementation of a habitat restoration program is a permitting requirement due to project activities.

Project Justification

This project facilitates compliance with the existing Department of Transportation (DOT) and California Public Utilities Commission (CPUC) requirements for safely operating and maintaining the natural gas pipelines within Sullivan Canyon.

Forecast Methodology

Cost forecasts are based on completed work from similar projects and estimated future pipeline exposure damage. Expected completion is Feb, 2012.

Schedule

Each year’s project activities will consist of engineering and design, materials procurement, permitting requirements, and construction.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements – Non-PIP Blanket	00312.33
WITNESS	**IN SERVICE DATE**
Ray Stanford	**Blanket**

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			333	299	122		754
DIRECT NONLABOR			3,208	3,444	1,396		8,048
TOTAL DIRECT CAPITAL			3,541	3,743	1,518		8,802
COLLECTIBLE			0	0	0	0	0
			3,541	3,743	1,518		8,802
FTE			3.6	3.2	1.3		8.1

Business Purpose
This Budget Code includes costs associated with the design and installation of transmission pipelines replacements. Typically, transmission pipelines are replaced due to either condition of existing pipeline or hazardous condition affecting the existing pipeline location. Pipelines with a history of significant leakage, poor coating, or that are difficult to cathodically protect are routinely evaluated for possible replacement. Not included on this work paper is the cost impact of new D.O.T. pipeline integrity requirements found in CFR 49, Part 192, Subpart 0.

This work paper includes recorded and estimated costs in Budget Codes 312, 322, and 332

Physical Description
Projects in this Budget Code include the cost to plan, design, permit, acquire materials, construct, commission, and mitigate impacts for the replacement of pipeline, fittings, valves, and associated pressure regulating stations and service lines. Multiple projects are completed each year ranging in size and magnitude from a few feet to several miles of replacement. Projects can involve difficult and hazardous access with many logistical challenges caused by weather or physical terrain.

Individual projects will vary from less than $10,000 to as high as multiple hundreds of thousands of dollars.

Project Justification
Estimate is based on an average of the most recent 3 years of recorded costs and on experience and judgment of local pipeline people with knowledge of trends in construction costs and materials performance.

Forecast Methodology
Cost forecasts were based on completed projects of similar scope.

Schedule
This is a blanket budget.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Storage Pipeline Capital Improvement / Externally Driven PDR Excess Compressor Piping Capital Abandonment	00312.95
WITNESS	**IN SERVICE DATE**
Ray Stanford	08/31/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			72				72
DIRECT NONLABOR			781				781
TOTAL DIRECT CAPITAL			853				853
COLLECTIBLE			0				0
NET CAPITAL			853				853
FTE			1.0				1.0

Business Purpose
On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description
Retire and remove all pressurized injection and withdraw piping associated with 6 natural gas compressor units that have been taken out of service at the Playa Del Rey Storage Field. This piping is currently within an HCA and, if not removed, would require baseline and future re-assessments under the Federal Pipeline Safety Improvement Act of 2002.

Project Justification
All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate

The piping associated with the out of service compressors serves no current or future purpose and the economic decision was made to retire and remove this piping systems rather than to leave it pressurized and perform the required routine maintain and PI assessments.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Storage Pipeline Capital Improvement / Externally Driven PDR Excess Compressor Piping Capital Abandonment	00312.95
WITNESS	**IN SERVICE DATE**
Ray Stanford	08/31/2010

Forecast Methodology

The majority of the costs to perform capital abandonment work are contract labor and equipment charges with little material required to complete the work. Our estimating methodology is based on historic contractor labor and equipment costs which is distilled down to a cost per day for the anticipated contract resources needed to accomplish the scope of work. This scope will require a contract crew size of 6 to 7 employees, a backhoe, welder, dump truck, crew truck, cranes and various other types of construction equipment. A typical daily cost for these resources comes to about $6,200 per day, including all overheads and support costs for the primary contractor. A one time unit cost of $205,000 is added to cover other contract support services like coating abatement, other hazardous material abatement and handling, etc. Material cost to complete this work is estimated at $80,000 and consists of misc. weld and mechanical fittings needed to separate the abandoned pipe from the remaining system that will stay in service.

The estimated duration required to fully complete this scope of work is approximately 80 days (80 X $6,200=$496,000 + $205,000 + $80,000= $781,000 Total Non-Labor).

The labor component for this type of work is estimated at about 8% of the non-labor (.078002 X $781,000 = $60,920 X 1.1807 V&S Factor= $71,928) and consists of the resources required to research records, planning and design, obtain permits and clearances, manage and coordinate the construction and assessment activities and project documentation and close out functions. An average salary for the classifications needed to carry out these activities is calculated at $82,500. The Company resources required to complete this effort is calculated at .87 of an FTE (Full Time Employee).

Schedule

The capital abandonment completion date, referred to as the in-service date for this project is: 08/31/2010.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation’s (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published new rule requiring an “integrity management” program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. This capital abandonment work has been scheduled for a time period that is commensurate with the risk ranking as well as operational and logistical constraints and will be completed in compliance with PSIA 2002.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Storage Pipeline Capital Improvement / Externally Driven Goleta Excess Storage Piping Capital Abandonment	00312.96
WITNESS Ray Stanford	**IN SERVICE DATE** 07/31/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR					16		16
DIRECT NONLABOR					84		84
TOTAL DIRECT CAPITAL					100		100
COLLECTIBLE					0		0
NET CAPITAL					100		100
FTE					.2		.2

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

Retire and remove pressurized well injection, withdraw, and support piping that have been identified as unnecessary for future operation at the Goleta Storage Field. This piping is currently within an HCA and, if not removed, would require baseline and future re-assessments under the Federal Pipeline Safety Improvement Act of 2002.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes and standards as appropriate

This misc. storage piping serves no current or future purpose and the economic decision was made to retire and remove this piping systems rather than to leave it pressurized and perform the required routine maintain and PI assessments.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Storage Pipeline Capital Improvement / Externally Driven Goleta Excess Storage Piping Capital Abandonment	00312.96
WITNESS	**IN SERVICE DATE**
Ray Stanford	07/31/2012

Forecast Methodology

The majority of the costs to perform capital abandonment work are contract labor and equipment charges with little material required to complete the work. Our estimating methodology is based on historic contractor labor and equipment costs which is distilled down to a cost per day for the anticipated contract resources needed to accomplish the scope of work. This scope will require a contract crew size of 6 to 7 employees, a backhoe, welder, dump truck, crew truck, cranes and various other types of construction equipment. A typical daily cost for these resources comes to about $6,200 per day, including all overheads and support costs for the primary contractor. A one time unit cost of $43,000 is added to cover other contract support services like coating abatement, other hazardous material abatement and handling, etc. Material cost to complete this work is estimated at $10,000 and consists of misc. weld and mechanical fittings needed to separate the abandoned pipe from the remaining system that will stay in service.

The estimated duration required to fully complete this scope of work is approximately 5 days (5 X $6,200=$31,000 + $43,000 + $10,000= $84,000 Total Non-Labor).

The labor component for this type of work is estimated at about 17% of the non-labor (.16619 X $84,000 = $13,960 X 1.1807 V&S Factor= $16,483) and consists of the resources required to research records, planning and design, obtain permits and clearances, manage and coordinate the construction and assessment activities and project documentation and close out functions. An average salary for the classifications needed to carry out these activities is calculated at $82,500. The Company resources required to complete this effort is calculated at .20 of an FTE (Full Time Employee).

Schedule

The capital abandonment completion date, referred to as the in-service date for this project is: 07/31/2012.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published new rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. This capital abandonment work has been scheduled for a time period that is commensurate with the risk ranking as well as operational and logistical constraints and will be completed in compliance with PSIA 2002.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission – Pipelines – Replacement Stormwater General Permit requirements	00312.97
WITNESS Ray Stanford	IN SERVICE DATE Blanket

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				0	0		0
DIRECT NONLABOR				69	69		138
TOTAL DIRECT CAPITAL				69	69		138
COLLECTIBLE				0	0		0
NET CAPITAL				69	69		138
FTE				0	0		0

Business Purpose

The State Water Resources Control Board's permit (the "Construction Stormwater General Permit" or "CGP") that regulates stormwater discharges from construction activities with one or more acres of soil disturbance was reissued on 9/2/09. This permit includes significant new risk-based requirements for construction projects, including but not limited to: inspections, sampling, effluent limits, reporting, specific minimum construction Best Management Practices (BMPs), post-construction BMPs, bioassessments and personnel certifications.

Physical Description

Permits to construct pipelines in Sediment-Sensitive Watersheds (SSWS) that will disturb 5 or more acres, including staging/storage areas, prescribe a process for permit issuance consisting of: Annual Fees, permit application prepared by a person holding "Qualified Prevention Plan Developer/Practitioner" qualification, Sampling/Bioassessment by a person similarly qualified, and runoff treatment as necessary, also by qualified individuals. Requirements differ as to whether a project will be in a medium-risk "Type 2" area or high-risk "Type 3" area.

Project Justification

This permit becomes effective 7/1/10. Projects that are started prior to 7/1/10, but will not be completed prior to that date, will have to reapply for coverage under the new permit prior to 7/1/10. Development of internal implementation programs has been initiated and will continue during the first half of 2010.

Forecast Methodology

To determine future exposure to the new rules, SCG studied five years of construction project records for the period 2005-2009 to determine how many of these projects took place in what is now Sediment Sensitive Watershed defined areas. For Transmission, the projects thus identified established an annual expectation of 0.347 projects starting per year in Type 2 areas and 0.053 projects starting per year in Type 3 areas. Applying these percentages to the activities described in "Physical Description" above, plus the percentages and costs for ongoing projects, yields the annual average expectation shown in this work paper. It should be noted that this submission asks only for an annual average amount. When an

PROJECT TITLE	BUDGET NO.
Gas Transmission – Pipelines – Replacement Stormwater General Permit requirements	00312.97
WITNESS	**IN SERVICE DATE**
Ray Stanford	Blanket

actual project starts in any given year, the costs for that particular year which are attributable to the new rules will be much higher than the average shown here.

Schedule
This is a blanket submission.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission – Pipelines – Replacements Pipe removals during replacement projects	00312.98
WITNESS	**IN SERVICE DATE**
Ray Stanford	**Blanket**

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				60	60		120
DIRECT NONLABOR				690	690		1,380
TOTAL DIRECT CAPITAL				750	750		1,500
COLLECTIBLE				0	0		0
NET CAPITAL				750	750		1,500
FTE				0.6	0.6		1.2

Business Purpose

Provides incremental capital funding for instances where a land owner or municipality will require removal of a pipeline being replaced in lieu of abandoning the old pipeline in place. The company has recently experienced an increase in requests for removal of pipelines that are being replaced in private lands and city streets which seem to be sourced in concerns that the abandoned line will conflict with future work or simply contribute to underground congestion and associated lack of available locations for future substructrures.

Physical Description

Instead of abandoning pipelines in place, which usually consists of plugging the open ends and sometimes filling the line with mud, the construction crew would physically remove the original pipeline from the street or right-of-way through extra paving cutting and excavation and by cutting it into sections and hauling it off to a disposal or recycling site.

Project Justification

As stated in the prepared testimony of witness John L. Dagg, in addition to reasons related to physical interference, a second reason for a removal request is that of landowners desiring to perfect legal title to their land. When SoCalGas holds an easement for a line that has been abandoned, the company is obligated to quit-claim the easement back to the landowner upon their request. In such cases, the landowner typically demands removal of the abandoned line in association with the quit claim.

In 2009, SoCalGas experienced eight intent-of-quit-claim notifications. Final resolution for each of these locations is presently unresolved. Such removals of pipelines in years subsequent to their abandonment is expensed. But if a removal at the time of their replacement or abandonment is required and/or prudent, the costs would be capitalized as part of the overall project scope. This submission provides for some of that capital increment.

Forecast Methodology

Since there is little, if any, history of pipe removals diring replacement project, as yet, we rely on the judgement of pipeline construction experts to estimate the increment that might be experienced. Since a

PROJECT TITLE	BUDGET NO.
Gas Transmission – Pipelines – Replacements Pipe removals during replacement projects	00312.98
WITNESS	**IN SERVICE DATE**
Ray Stanford	**Blanket**

large part of a pipeline project's costs, approximately a third, are for paving removal, restoration and excavation, and because pipeline removal could nearly double that portion of the costs, we estimate the increment at between 30% and 36%. When this increment is applied to the dimensions of a single existing removal project, 7,500 ft. of 26 inch pipe in the City of Burbank, and we apply 36% to a direct replacement cost estimate of $2,081.3k, we arrive at the $750k per year estimate presented in this work paper. We consider this to be a conservative and reasonable place holder for costs that could be far higher in future years and especially as franchise renewalls come due and include tighter requirements for removal.

Schedule

This is a blanket project.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Relocations - Freeway	00313.00
WITNESS	**IN SERVICE DATE**
Ray Stanford	Blanket

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR		133	41	80	80		334
DIRECT NONLABOR		1,004	978	1,930	1,930		5,842
TOTAL DIRECT CAPITAL		1,137	1,019	2,010	2,010		6,176
COLLECTIBLE		(568)	(1,019)	(1,005)	(1,005)		(3,597)
NET CAPITAL		569	0	1,005	1,005		2,579
FTE		1.1	0.4	0.9	0.9		3.3

Business Purpose
This Budget Code includes costs associated with pipeline and associated facility relocations necessitated by Cal Trans construction projects. Included here are historic and forecast costs in Budget Codes 303, 313, 323, and 333.

Physical Description
Relocate and replace pipelines and related facilities found to be in conflict with Cal Trans construction projects. Individual projects will vary from less than $10,000 to as high as multiple hundreds of thousands of dollars.

Project Justification
To meet operating, right of way, and franchise agreement requirements. Ongoing projects with Cal Trans are not always known during the annual budgeting process. Throughout the year, SoCalGas is required to relocate pipelines during the same year they are being submitted to SoCalGas. Costs are driven by safety and regulatory compliance as well as contractual requirements.

The forecast for 2010 is based on the 2010 budget for this Budget Category. 2011 and 2012 are based on the most recent five-year average of recorded costs, less collections, and trends within Cal Trans which indicate these projects will continue during the forecast period and as represented by recent history.

Forecast Methodology
Average of five recorded years expenditures, 2005-2009.

Schedule
This is a blanket budget.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Relocations – Franchise & Private & Right of Way - Blanket	00314.00
WITNESS	**IN SERVICE DATE**
Ray Stanford	Blanket

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR		524	120	47	0		691
DIRECT NONLABOR		5,043	1,020	280	0		6,343
TOTAL DIRECT CAPITAL		5,567	1,140	504	0		7,211
COLLECTIBLE		Unk	(491)	(216)	0		(708)
NET CAPITAL		5,567	649	287	0		6,503
FTE		5.5	1.3	0.5	0		7.3

Business Purpose

This Budget Code includes costs associated with the modification and relocation of transmission pipelines to accommodate planned private property development, municipal public works and street improvement projects, and other work required due to right-of-way agreements, contract and franchise requirements.

Included in this submission are recorded and estimated costs in Budget Codes 304, and 314, less specific jobs known to be upcoming.

Physical Description

This Budget Code contains forecasts for a number of pipeline relocation projects required to meet the regulatory requirements or contract clauses of operating, right of way, franchise, and 3rd party developer agreements. Specific projects with cities and developers are not always clear during the annual budgeting process. These projects can range in magnitude from less than one hundred feet of pipe to accommodate a storm drain or sewer installation to several miles of relocated pipe, fittings, valves and appurtenances needed to accommodate residential development over large tracts of previously undeveloped land throughout our service territory. Throughout the year, SoCalGas can be required to relocate pipelines during the same year the request is received by SoCalGas due to the immediate needs of third party developers or municipal agencies.

Individual projects in this budget code can vary in cost from less than $10,000 to as high as several hundreds of thousands of dollars.

Project Justification

Pipelines are relocated according to the requirements of municipal franchises and property developers. Some are collectible and others are not, usually depending on rights of way language. Estimated years are an average of the most recent three recorded rears less specific projects known to be upcoming.

Forecast Methodology

Forecast for 2010 is based on the 2010 Budget for this Budget Category. 2011 and 2012 are based on a five-year average of costs in this Budget Category, 2005-2009. The amounts shown here are the differences between amounts for known projects and the aforementioned five-year averages.

Schedule

This is a blanket budget.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Line 7039 - Westside Parkway - at Renfro Road	0314.01
WITNESS	**IN SERVICE DATE**
Ray Stanford	09/30/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			280	0	0	0	280
DIRECT NONLABOR			2,010	0	0	0	2,010
TOTAL DIRECT CAPITAL			2,290	0	0	0	2,290
COLLECTIBLE			0	0	0	0	0
NET CAPITAL			2,290	0	0	0	2,290
FTE			3.0	0	0	0	3.0

Business Purpose
Relocate Line 7039 in the City of Bakersfield Westside Parkway and Renfro Road due to roadway reconstruction.

Physical Description
24" Line 7039 is now located within Renfro Road. The City of Bakersfield plans to develop Westside Parkway which crosses Renfro Road. The Renfro Road crossing will be an Overcrossing. The pipeline will require relocation into a cell within the newly constructed bridge crossing Renfro Road. The pipeline relocation will consist of 30" casing pipe and 24" carrier pipe.

Project Justification
The existing 24” pipeline must be relocated by SoCalGas because it is in direct conflict with roadway construction and is installed under terms of our franchise with the City of Bakersfield.

Forecast Methodology
The estimated cost is based on discussions with a reputable Contractor, materials cost inquires, and on similar scope jobs in similar locations.

Schedule
The City of Bakersfield projects completion of the bridge and cell during 2nd quarter 2010, ready for our installation 3rd quarter 2010.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Line 2002 PXP Montebello Relocation Project	0314.02
WITNESS	**IN SERVICE DATE**
Ray Stanford	05/31/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			33	100	0	0	133
DIRECT NONLABOR			982	2,900	0	0	3,882
TOTAL DIRECT CAPITAL			1,015	3,000	0	0	4,015
COLLECTIBLE			0	0	0	0	0
NET CAPITAL			1,015	3,000	0	0	4,015
FTE			0.4	1.1	0	0	1.5

Business Purpose

This project relocates a portion of an existing 30-inch diameter gas transmission pipeline (Line 2002), located on Plains Exploration and Production (PXP) Company Montebello Oil Field. The pipeline and associated infrastructure are in conflicts with PXP's well development plans and have to be relocated pursuant to the provisions of the Right of Way (ROW) and easement agreement between PXP and Southern California Gas (SCG) Company. Project is located on PXP Montebello Oil Field property in Los Angeles County, California.

Physical Description

PXP has identified the portion of the pipeline requiring relocation in order to accommodate the proposed well development. Based on the development plans submitted to SCG, PXP has presented the option of relocating approximately 5,000 linear feet of existing pipe onto the oil field maintenance road. However, SCG may be required to relocation the entire pipeline on PXP property, approximately 7,500 linear feet, to accommodate PXP's current and future development plans. The latter option would result in relocating the pipeline onto city streets around the PXP property.

Project Justification

SCG is required to relocate approximately 3, 400 linear feet of the existing pipeline located on PXP property due to contractual obligation. However, relocating a portion of the pipeline does not eliminate the need to relocate the entire pipeline in the near future. Based on recent development plans provided by PXP; SCG believes it is prudent to relocate at the present time a portion of the pipeline to accommodate well development with a caveat of potential future relocation for the rest of the pipeline. Furthermore, Line 2002 is a critical system for supply into the Los Angeles basin.

Forecast Methodology

Project cost estimate was prepared with information provided by a pipeline contractor for budgetary purpose. Other direct costs are based on a recently completed project with similar scope of work in the region.

Schedule

Construction work is expected to begin in August 2010 and conclude by May 31, 2011.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Orange County Gateway Grade Separation Projects, Line 1016 & Line 4000	00314.03
WITNESS	**IN SERVICE DATE**
Ray Stanford	06/30/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				156	312	0	468
DIRECT NONLABOR				4,370	8,740	0	13,110
TOTAL DIRECT CAPITAL				4,526	9,052	0	13,578
COLLECTIBLE				(1,358)	(2,716)	0	(4,074)
NET CAPITAL				3,168	6,336	0	9,504
FTE	0	0	0	1.7	3.4	0	5.1

Business Purpose
To alleviate congestion in the Cities of Placentia, Fullerton and Anaheim, OCTA is planning a series of grade separations along railroad crossings throughout those cities. The plan involves undercrossings/overcrossings at up-to 12 intersections. Currently, six (6) grade separations are in the planning phase. These are:

1) Kraemer Blvd (undercrossing)
2) Lakeview Avenue (overcrossing)
3) Raymond Avenue (undercrossing)
4) State College Blvd (undercrossing)
5) Orangethorpe Avenue (overcrossing)
6) Tustin Avenue / Rose Drive (overcrossing)

In order for the OCTA to qualify for federal $ (along w/ OC Measure M $), their projects must be in construction prior to the end of the 2013 calendar year. SCG must be relocated prior to OCTA construction

Physical Description
These grade separations will involve the relocation of 36-inch Line 1016, 36-inch Line 4000 or both. The OCTA has stated most overcrossings may be designed to avoid conflict with SCG pipelines (except Orangethorpe). The three (3) undercrossings will require relocation of our pipeline(s)

Project Justification
Mandatory due to conflict with future roadways. Depending upon location, our pipeline(s) will have prior rights by easement. Other conflicts will be non-collectible due to franchise requirements

Forecast Methodology
Estimates are based on previous costs on similar projects. These are rough estimates due to the early stages of planning on the part of the OCTA at this time.

Schedule

1) Kraemer Blvd (estimated SCG construction first quarter of 2011)
2) Lakeview Avenue (estimated SCG construction third quarter of 2011, if necessary)
3) Raymond Avenue (estimated SCG construction second quarter of 2012)
4) State College Blvd (estimated SCG construction third quarter of 2012)
5) Orangethorpe Avenue (estimated SCG construction fourth quarter 2012)
6) Tustin Avenue / Rose Drive (estimated SCG construction fourth quarter of 2012, if necessary)

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Line 2001 RELOCATION – NOGALES ST.	0314.04
WITNESS	**IN SERVICE DATE**
Ray Stanford	06/30/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR		59	48	0	0	0	107
DIRECT NONLABOR		525	1,522	0	0	0	2,047
TOTAL DIRECT CAPITAL		584	1,570	0	0	0	2,154
COLLECTIBLE		(251)	(675)	0	0	0	(926)
NET CAPITAL		332	895	0	0	0	1,228
FTE		0.6	0.5	0	0	0	1.1

Business Purpose
The City of Industry is planning a grade separation project along Nogales Street, causing the Gas Company to relocate approximately 2000 feet of Line 2001, which is in direct conflict with the retaining wall.

Physical Description
Procure, permit, and install approximately 2000 feet of 30 inch Line 2001 in the City of Industry. Remove 560 feet of existing 30 inch L-2001.

Project Justification
Relocate approximately 2000 feet of 30 inch Line 2001, which is in direct conflict with the City of Industry grade separation project on Nogales St. and Union Pacific railroad. The grade separation retaining wall will be in conflict with Line 2001, causing the Gas Company to relocate around Nogales Street.

Project is 43% collectible; 57% non-collectible.

Forecast Methodology
The estimated cost was derived by using internal cost estimating spreadsheet which contains unit costs for contract labors and materials from previous projects of similar size and scope.

Schedule
The city has requested that the relocation work be completed by the end of June, 2010.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Line 1018 - Sand Canyon Avenue Grade Separation	00314.05
WITNESS	**IN SERVICE DATE**
Ray Stanford	08/31/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			84	0	0	0	84
DIRECT NONLABOR			845	0	0	0	845
TOTAL DIRECT CAPITAL			929	0	0	0	929
COLLECTIBLE			(929)				(929)
NET CAPITAL			0				0
FTE			0.9	0	0	0	0.9

Business Purpose
Relocate Line 1018 in the City of Irvine at Sand Canyon Avenue as required to clear construction of highway/railroad separation at grade.

Physical Description
Relocate approximately 330-feet of 30-inch Line 1018 to avoid conflict with grade separation.

Project Justification
Mandatory due to existing location within railroad grade separation project. Project is collectible from the City of Irvine due to Pipeline easement agreement dating to 1965.

Forecast Methodology
Estimates are based on previous costs associated with similar projects

Schedule
Construction is scheduled to begin June/July, 2010 and should take approximately 2 months to complete

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Relocate Line 2000 for McMaster-Carr – Santa Fe Springs	00314.06
WITNESS	**IN SERVICE DATE**
Ray Stanford	05/31/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				24	71	0	95
DIRECT NONLABOR				75	1,982	0	2,057
TOTAL DIRECT CAPITAL				99	2,053	0	2,152
COLLECTIBLE				(99)	(2,053)	0	(2,152)
NET CAPITAL				0	0	0	0
FTE				0.3	0.8	0	1.1

Business Purpose
Relocate pipeline around new planned development and associated construction zone to eliminate interference with existing pipeline location. McMaster-Carr is planning to expand their warehouse building.

Physical Description
Relocate approximately 2,800 feet of 26" Line 2000 to accommodate the proposed new development (expanded warehouse).

Project Justification
Terms of SoCalGas easement for Line 2000 makes this project 100% collectible from McMaster-Carr.

Forecast Methodology
Project cost estimate is based on previous experience with projects of similar pipe size and scope.

Schedule
Original planned completion date was December 30, 2010. However, McMaster-Carr has postponed project construction.
Project is scheduled to require relocation of SoCalGas pipeline by mid-2012. Planning will take place in 2011.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
LINE 2001- RIVERSIDE AIRPORT RELOCATION	0314.07
WITNESS	**IN SERVICE DATE**
Ray Stanford	10/31/1010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR	37	4	12	0	0	0	53
DIRECT NONLABOR	508	15	388	0	0	0	911
TOTAL DIRECT CAPITAL	545	19	400	0	0	0	964
COLLECTIBLE	(545)	(19)	(400)	0	0	0	(964)
NET CAPITAL	0	0	0	0	0	0	0
FTE	0.4	0	0.1	0	0	0	0.5

Business Purpose

Riverside Municipal Airport has requested the Gas Company to relocate approximately 3,000 feet of 30-inch gas main to make way for extension of the main runway.

Physical Description

This project consists of design, permit and construct approximately 3000 feet of 30 inch gas main. This project also includes the removal of approximately 1,600 and the abandonment of 1,400 feet of existing 30 inch Line 2001.

Project Justification

This relocation is 100% collectible due to the pipeline's prior rights and is required in order to accommodate the Airport's runway extension.

Forecast Methodology

The estimated cost was derived by using internal cost estimating spreadsheet which contains unit costs for contract labors and materials from previous projects of similar size and scope.

Schedule

This project is expected to begin in 3rd Quarter of 2010 pending completion of the Environmental Impact Report by Riverside Airport and should be complete by the end of October, 2010.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Jeffrey Road Grade Separation – Line 1018	0314.08
WITNESS	**IN SERVICE DATE**
Ray Stanford	09/30/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR	46	20	167	0	0	0	233
DIRECT NONLABOR	84	229	840	0	0	0	1153
TOTAL DIRECT CAPITAL	130	249	1,007	0	0	0	1,386
COLLECTIBLE	(130)	(249)	(1,007)	0	0	0	(1,386)
NET CAPITAL	0	0	0	0	0	0	0
FTE	0.5	0.2	1.8	0	0	0	2.5

Business Purpose

This project is a required part of the Jeffrey Road Grade Separation Project located in the City of Irvine California due to our pipeline being in direct conflict.

Physical Description

The project consists of relocating approximately 660 feet of 30-inch nominal diameter Line 1018. Installation will include 3 each casings. Two casings will be located under the Metrolink railroad tracks and one will be installed in a pedestrian bridge that crosses Jeffrey Road.

Project Justification

Project is required to accommodate the city of Irvine's Jeffrey Road Grade Separation. City of Irvine is paying 100% of the cost of this project.

Forecast Methodology

Estimated cost was determined based on identifying individual tasks and the equipment, materials and labor each task would require to complete. The project required two phases.

Schedule

Phase 1 included installing a 160-foot 'pre-lay' section of 30-inch diameter pipeline. Phase 2 includes installation of the casings and remainder of the 30-inch diameter pipeline. The entire pipeline segment will be placed into service by Sept. 30, 2010.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Placentia Avenue Grade Separation Project, Line 1013	0314.09
WITNESS	IN SERVICE DATE
Ray Stanford	10/30/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			78	0	0	0	78
DIRECT NONLABOR			1,676	0	0	0	1,676
TOTAL DIRECT CAPITAL			1,753	0	0	0	1,753
COLLECTIBLE			0	0	0	0	0
NET CAPITAL			1,753	0	0	0	1,753
FTE			0.8	0	0	0	0.8

Business Purpose
Relocate Line 1013 due to Orange County Transportation Authority project to alleviate traffic congestion at BNSF railroad crossing at grade.

Physical Description
approximately 2,100-feet of 24-inch Line 1013 due to conflict with railroad grade separation.

Project Justification
Mandatory to fulfill obligations of franchise agreement with Cities of Placentia and Fullerton. Project is not collectible due to Franchise requirements.

Forecast Methodology
Estimates are based on previous costs associated with similar projects

Schedule
Construction is scheduled to begin July, 2010 and should take approximately 2.5 months to complete.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Compressor Station Additions/Replacements - Blanket	00315.00
WITNESS	**IN SERVICE DATE**
Ray Stanford	Blanket

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR		420	53	199	22		694
DIRECT NONLABOR		2,094	513	1,092	501		4,200
TOTAL DIRECT CAPITAL		2,514	567	1,291	523		4,895
COLLECTIBLE		0	0	0	0	0	0
NET CAPITAL		2,514	567	1,291	523		4,895
FTE		4.4	0.6	1.9	0.2		7.1

Business Purpose

This Budget Code includes costs associated with the installation and replacement of compressor station equipment used in operating the transmission system. The nature of compressor station operation requires consistent maintenance and replacement of key engine components and controls equipment to ensure the reliability and safety of the facility. To keep operating costs down, reliance is made on automating data gathering systems to monitor performance data such as flows, pressures, and temperatures. The upgrade and replacement of controls consisting of out dated technology is critical to ensure the station is operating at its highest efficiency and that proper testing and diagnostics can be executed when the engine units are down. New air quality regulations require emissions monitoring and reporting equipment along with new catalyst and combustion technology to meet lower emission levels.

Costs recorded and estimated in budget categories 305, 315, and 335 are included in this submission.

Physical Description

Individual project scopes can consist of one or a combination of the following installations: replacing the pneumatic and electro-mechanical control systems and related station auxiliary systems, installation of new engine control panels, new station control panel and replacement of sensors, wiring, industrial communications and local controllers. New Programmable Logic Controllers, local control networks, operator interfaces, continuous emissions monitoring (CEMS), pre combustion chambers, and new catalysts.

Project Justification

Compressor engine components have a finite life requiring regular replacement and/or upgrade as recommended by the manufacturer to ensure reliability and transportation ability for the Southern California market. For older stations where existing control and auxiliary equipment technology are outdated, replacements are required to interface with newer data acquisition systems and air quality mandated emission system upgrades.

Forecast Methodology

The 2010 forecast is based on the 2010 budget amount for several small projects not qualifying for their own work paper plus a blanket amount of $101k for small projects that arise during the year. 2011 and 2012 is the sum of several smaller projects that do not qualify for their own work paper. They are entirely specific projects with no amount set aside for small projects arising during the year.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Compressor Station Additions/Replacements - Blanket	00315.00
WITNESS	**IN SERVICE DATE**
Ray Stanford	Blanket

Schedule

This is a blanket project.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Newberry Station Controls Upgrade	00315.01
WITNESS	**IN SERVICE DATE**
Ray Stanford	09/30/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR					214		214
DIRECT NONLABOR					3,169		3,169
TOTAL DIRECT CAPITAL					3,383		3,383
COLLECTIBLE					0	0	0
NET CAPITAL					3,383		3,383
FTE					2.3		2.3

Business Purpose
This Budget Code includes costs associated with compressor stations additions and replacements.

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Physical Description
This project consists of replacing the pneumatic and electro-mechanical control systems on (7) Clark TLA internal-combustion, engine-driven compressor units and related station auxiliary systems at Newberry Springs Compressor Station. Scope of work includes installation of new engine control panels for each unit, new station control panel and replacement of sensors, wiring, industrial communications and local controllers. New Programmable Logic Controllers, local control networks, and operator interfaces will also be installed. This work supports both station reliability and the need to upgrade basic control system infrastructure to leverage the pending installation of air-fuel, ignition and catalyst systems which are planned for in 2012 to support more stringent Environmental Protection Agency regulations governing large internal combustion engine emissions. This companion work is described in the Direct Testimony of Mr. Raymond K. Stanford under the capital work paper entitled “Gas Transmission Compressor Station Additions/Replacements RICE NESHAPS / Rule 1160 Compliance Project.“ The control work is presented separately because it has value above and beyond the emission reduction compliance arena - it can stand alone on reliability and related avoided cost considerations.

Project Justification
Newberry Compressor Station is one of SoCalGas’ most important transmission facilities. This 44 year-old compressor station enables SoCalGas to receive from suppliers and route nearly ½ trillion cubic feet of gas per year to customers, electric generating facilities and/or underground storage fields. The station is located just outside the desert town of Newberry Springs, 100 miles west of the California Border along Interstate 40, at the junction of 2 gas transmission lines (numbers 235 and 3000.) These pipelines receive gas from Transwestern, Questar and El Paso pipeline companies’ inter-connection points located at Needles, Ca. Newberry Station compresses these delivered gas volumes either directly west toward the north LA Basin near Saugus, or southwest toward the inland empire and Orange County for direct service to electric generating plants, SDG&E and mass market customers.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Newberry Station Controls Upgrade	0315-1
WITNESS	**IN SERVICE DATE**
Ray Stanford	12/31/2012

The reliability of this station is of critical import to SoCalGas' mission to serve its customers and avoid interruption of service to electric generating facilities. This mission is accomplished by the reliable operation of seven (7) large internal combustion engine-driven compressor units. Each of these units delivers 2000 horsepower of compression to move gas along in large transmission pipelines. Major ancillary system supporting this compression are gas, jacket water and oil cooling, electric generation, fuel delivery systems, compressor pocket control, odorization facilities and a series of valves, to manage gas flows within the station and to/from external pipelines. The load factor for this partially-manned facility is over 70% and, more importantly, sustained loss of this station for more than 30-days would have a major impact on SoCalGas ability to meet its service obligations and drive gas prices upward by as much as $0.25 per MMbtu for the duration of its non-operation. The cost to customers for such a failure is estimated to be $100,000 per day or $3MM per month.

While SoCalGas has managed to keep the main mechanical components of this station operating reliably for over forty years, there are many smaller components (24-44 years old) which undermine station reliability through failure. These include aging wiring, pneumatic switches, valves and electronic components subject to temperature extremes associated with desert operation. These failures have increased in recent years at Newberry Stations, and have caused engine start/availability issues monthly for the past 3 years. SoCalGas has managed around these failures and related parts availability issues, but believes these failures will accelerate over the next three years and beyond. This progression will result in: an untenable reliability drop, escalating O&M cost to (sequentially and under-duress) replace control system components, higher gas prices and the negative public perception regarding prudent management of the southern California energy infrastructure by all parties.

SoCalGas experienced this negative progression at its North and South Needles compressor stations (prior to their similar upgrades completed over the period 2002-2006) and elects to upgrade one of its most valued assets prior to sustained reliability reduction.

SoCalGas plans to spend $3.383 million in year 2012 to avoid a sustained decline in Newberry Springs Compressor station availability and the consequences thereof. Offsets to the costs are principally avoided: future O&M, fragmented capital replacement cost, and customer impacts. Compliance with expected EPA emission control protocols are also supported by this work.

A summary of the non-compliance offsets/benefits are as follows:

- Gas cost avoidance: Estimated one (1) 30-day station-equivalent shutdown avoided each 3-year period, which affects gas prices by $0.25 per MMbtu (price pressure placed on alternate delivery points.) Newberry incremental capacity (or loss): 400 MMcf/d. Gas costs to customers increases by $100,000 per day = $3MM per incident = $1MM annualized.

- O&M escalation avoidance: SoCalGas fully expects to replace the subject control components over the next 4-10 years, either through a planned and cost-efficient manner or through a replace- at-failure method, which, based on experience, SoCalGas estimates to costs 50% more than planned replacements. The fragmented replacement of failing components is expected to cost $4.7 MM over a 10-year period (average $470,000 per year.) It is more probable that SoCalGas might attempt this patchwork replacement approach for 2-3 years, become over burdened with the aforementioned reliability reduction, inability to achieve emission control objectives with obsolete control technology and related cost and problems, then elect to move-on to full replacement anyway. (The common technology analogy would be sequentially replacing each and every electromechanical component in a 44 year old automobile, upon failure, in an

PROJECT TITLE Newberry Station Controls Upgrade	BUDGET NO. 0315-1
WITNESS Ray Stanford	IN SERVICE DATE 12/31/2012

attempt to keep it as reliable as a new vehicle.) In either case, SoCalGas believes the alternatives to planned replacement are more costly and place added risk to SoCalGas' operational integrity and ability to meet lower engine emission standards.

- Fuel cost savings/avoidance: it is estimated more efficient operation of Newberry Compressor Station can be managed by improved control system performance and monitoring. Estimated benefit: 2% of total fuel used or $50,000 per year.

- O&M reduction over baseline control system work: $25,000 per year. (call-outs, extended diagnostics and repairs.)

- Early detection and trending of potential major mechanical component failures. Avoid one crankshaft, turbo and 3 cylinder replacements each 10=year cycle. Estimated benefit: $50,000 per year.

- Curtailment avoidance: Move station reliability to 98.5% from 97.5%: reduce the risk of curtailment associated with this station by 5/6th (1 event per 16.7 years - based on current reliability- extends to 1 event per 100 years.) Curtailment risk will increase to 1 event per 10 years over next three years under "do-nothing" scenario.

- The cost to customers for having to shut-down the station - due to the inability to effectively meet EPA emission standards- can range upwards of $100,000 per day in incremental gas costs if such shutdown constrains the ability of SoCalGas to move gas from historically price-favorable interconnects.

Simple annualized cost avoidance totals, not assuming emission reduction considerations: $1.545 million. SoCalGas believes the combination of tangible avoided costs and operating risks; and the need to comply with EPA air quality regulations warrant the replacement of Newberry Springs Compressor Station control systems as a capital project over the GRC period 2010-2012.

Forecast Methodology

The cost for this station capital work is based upon preliminary engineering scope-of-work/specifications and a previously-awarded bid for the job, which has been deferred two years. Several pieces of that work scope and estimate have been modified to accommodate EPA emissions work integration in 2012.

Schedule

All engineering, construction work and commissioning is scheduled to take place in 2012, with full implementation expected by Sept. 30 of that year.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Transmission Compressor Stations – Adds & Repl - Ventura Station Controls	00315.02
WITNESS	**IN SERVICE DATE**
Ray Stanford	09/30/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR		59	236	0	0	0	295
DIRECT NONLABOR		0	1,500	0	0	0	1500
TOTAL DIRECT CAPITAL		59	1,736	0	0	0	1,795
COLLECTIBLE		0	0	0	0	0	0
NET CAPITAL		59	1,736	0	0	0	1,795
FTE		0.6	2.5	0	0	0	3.1

Business Purpose

This project sustains and improves the reliability of Ventura Compressor station through the upgrade of antiquated compressor, engine and station auxiliary control systems used to remotely operate the station. This critical station directly supports 8 Bcf of gas injection annually for customers and is used to serve customers north of Ventura on cold winter days and when California producers in the North coast are shut in or reduced in deliveries. It is critical for meeting seasonal storage inventory targets to serve customers and help keep gas costs low for all customers in Southern California.

Physical Description

Replacement of antiquated pneumatic and electro-mechanical control systems used to operate three high-pressure IC-engine-driven gas compressors and related ancillaries. Modernize station operations in advance of major degradation of station reliability. Replace components in three engine/compressor unit panels and upgrade the fuel, ignition, vibration and engine health monitoring of each unit. Replace/upgrade the control systems operating all major ancillary systems including gas, jacket water and oil cooling; and all station valves to support operations. These systems components range in age from 21-84 years old. This station was constructed in 1922, with limited compressor control system upgrades last occurring in 1989.

Project Justification

This project supports transmission system reliability, the reduced risk of customer curtailment, and management of gas cost for customers. Ventura compressor station is principally used to support the injection of gas into Goleta Storage field in summer and to serve the North Costal area of SoCalGas service territory (Ventura to Manta Maria) in winter and when producer gas and Goleta storage field supplies are either unavailable or of limited capacity. This 3300 horsepower compressor station services 22 Bcf of storage and can deliver up to 90 MMcf/d to the North Coastal pipelines. When in compression mode, Ventura provides uninterrupted service to SoCalGas customers north of Ventura. Without the availability of this station, it is estimated approximately 100,000 customers north of Ventura would be curtailed or lose service once per year (at times when high load is coupled with storage limitations and producer shut-ins.) The cost associated with relighting these customers is, at minimum $5 million per incident. Current station availability of approximately 96% means the probability of this type event occurring is once per 25 years. SoCalGas' minimum criterion for any single large compressor facility is one incident per 100 years. It is anticipated station availability will decline to 92% or less if the series of existing controls are not replaced over the next 3-7 years. This decline in performance would drop the

PROJECT TITLE	BUDGET NO.
Transmission Compressor Stations – Adds & Repl - Ventura Station Controls	00315.02
WITNESS	IN SERVICE DATE
Ray Stanford	09/30/2010

curtailment probability to a 1 in 10 year event frequency, or more as customer load growth along the north coast ensues. SoCalGas finds this single facility operational probability unacceptable and will look to mitigate this risk through the upgrade of station controls. Calculated risk avoidance associated with this work is $200,000 per year. (This excludes consideration of any public relations or regulatory costs.)

Ventura station singularly provides 8 Bcf of injection capacity into Goleta storage field. This capacity not only sustains gas service to customers, but also buffers customers from extreme gas costs. The value of this capacity is conservatively estimated at $0.20 per Mcf. Applied to 8 Bcf, the value of Ventura compression is $4 MM annually. A 4% percent reduction in system availability to support such future operations has an equivalent value of $160,000 per year.

Automated controls on station valves also support the movement of Goleta withdrawal and producer gas receipts to customers in Ventura and south thereof. The ability to remotely control these valves has already degraded over past seven years and SoCalGas believes the appropriate routing of 340 MMcf/d of gas withdrawal must be managed with reliable controls and mechanical infrastructure. Replacement of this station sub-system, which provides direct gas service to over 300,000 small customers and several large electrical generation plants in Ventura County is also included in the scope of this project upgrade.

The foregoing risks/benefits aside, without an approved capital project, SoCalGas will replace and repair the system controls at Ventura station over the next 7 years as major and minor components fail and replacement parts are no longer available. It is expected that the cost associated with episodic replacement of control components under duress will costs at least 50% more ($100,000 per year annualized) than the planned and managed upgrade of these components through a comprehensive upgrade. This concept is similar to running a 20-year old car and repairing single components as they fail (after paying for towing, hotels and other related costs), versus the planned upgrade of major sub-systems in one project to make the automobile runs reliably in a single service call. Ventura station is the equivalent of a 20 year-old car (actually 85 years old in some instances) in need of new fuel injection/ ignition, emission systems, wiring, switches, fans and other bolt on components. Unlike an automobile, the operating stakes are much higher and, the base mechanical components, (compressor, engines, cooling apparatus) being properly maintained, still possess much value and future life expectancy after 20 years. Thus, upgrade of $1.75MM in electro-mechanical and digital control systems helps extend the life of $10 million in mechanical infrastructure.

The collective benefits of upgrading the control systems at Ventura station are estimated to be $460,000 per year. A capital cost of $2.0 MM places the simple payback for this project at 4+ years.

Forecast Methodology

A detailed Engineering Scope of Work was produced for this project and cost estimate received from engineering contractors. SoCalGas has performed similar upgrades at four of its other compressor stations over the past 6 years and places great confidence in the forecasted costs based on this experience.

Schedule

This project was scoped and planned in 2009 and is scheduled to be bid, awarded, and completed in Sept. 2010.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Compressor Station Additions/Replacements - Cactus City Compressor Station Controls Upgrade	00315.03
WITNESS	**IN SERVICE DATE**
Ray Stanford	09/30/2013

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				89	89	200	378
DIRECT NONLABOR				455	455	330	1,240
TOTAL DIRECT CAPITAL				544	544	530	1,618
COLLECTIBLE				0	0	0	0
NET CAPITAL				544	544	530	1,618
FTE				1.0	1.0	2.5	4.5

Business Purpose
This Budget Code includes costs associated with the controls upgrade and replacement at the Cactus City Compressor Station. The station is located 20 miles east of Indio along Interstate 10 in Riverside County. The station consists of one 6,200 horsepower General Electric Frame 3 gas turbine engine driving a DeLaval centrifugal compressor. It was placed into service in 1952 to provide additional "take-away" and capacity through Blythe Station and to provide additional downstream (westerly) pressures in Lines 1030/2000, 2001, and 5000. The station is unmanned and is operated by remote control from Blythe Station or Gas Operations. The station has not received any significant controls replacement or upgrades since the early 1980’s and its operation relies on outdated technology which compromises its ability to start and run efficiently.

Physical Description
This project consists of replacing the pneumatic and electro-mechanical control systems on the General Electric Frame 3 turbine engine and related station auxiliary systems at the Cactus City Compressor Station. Scope of work includes installation of a new engine control panel, new station control panel and replacement of sensors, wiring, industrial communications and local controllers. A new Programmable Logic Controllers, local control network, and operator interfaces will also be installed.

Project Justification
The reliability of this station compromises SoCalGas’ ability to efficiently operate critical transmission pipelines during periods when demands on the system are high. Major ancillary systems supporting this compression are the jacket water and oil cooling system, fuel delivery system, air compression system, recuperator and exhaust system, and a series of valves to manage gas flows within the station and to/from external pipelines. While SoCalGas has managed to keep the main mechanical components of this station operating reliably for close to 60 years, there are many smaller components (20-40 years old) which undermine station reliability through failure. These include aging wiring, pneumatic switches, valves and electronic components subject to temperature extremes associated with desert operation. These failures have increased in recent years and have caused consistent engine start/availability issues. SoCalGas has managed around these failures and related parts availability issues, but believes these failures will accelerate over the next three years and beyond.

Forecast Methodology

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Compressor Station Additions/Replacements - Cactus City Compressor Station Controls Upgrade	00315.03
WITNESS	**IN SERVICE DATE**
Ray Stanford	09/30/2013

Cost forecasts were based on completed controls upgrade projects at the following SCG compressor stations: North Needles, South Needles, and Kelso.

Schedule
Years one and two of the project will consist of engineering and design, as well as the procurement of major devices, while year three will include installation and start up.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Compressor Station Additions/Replacements Desert Center Compressor Station Controls Upgrade	00315-04
WITNESS	**IN SERVICE DATE**
Ray Stanford	09/30/2013

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				89	89	236	414
DIRECT NONLABOR				455	455	330	1,240
TOTAL DIRECT CAPITAL				544	544	566	1,654
COLLECTIBLE				0	0	0	0
NET CAPITAL				544	544	566	1,654
FTE				1.0	1.0	2.5	4.5

Business Purpose

This Budget Code includes costs associated with the controls upgrade and replacement at the Desert Center Compressor Station. The station is located one mile east of Desert Center along Interstate 10 in Riverside County. The station consists of one 6,200 horsepower General Electric Frame 3 gas turbine engine driving a DeLaval centrifugal compressor. It was placed into service in 1952 to provide additional "take-away" and capacity through Blythe Station and to provide additional downstream (westerly) pressures in Lines 1030/2000, 2001, and 5000. The station is unmanned and is operated by remote control from Blythe Station or Gas Operations. The station has not received any significant controls replacement or upgrades since the early 1980's and its operation relies on outdated technology which compromises its ability to start and run efficiently.

Physical Description

This project consists of replacing the pneumatic and electro-mechanical control systems on the General Electric Frame 3 turbine engine and related station auxiliary systems at the Desert Center Compressor Station. Scope of work includes installation of a new engine control panel, new station control panel and replacement of sensors, wiring, industrial communications and local controllers. A new Programmable Logic Controllers, local control network, and operator interfaces will also be installed.

Project Justification

The reliability of this station compromises SoCalGas' ability to efficiently operate critical transmission pipelines during periods when demands on the system are high. Major ancillary systems supporting this compression are the jacket water and oil cooling system, fuel delivery system, air compression system, recuperator and exhaust system, and a series of valves, to manage gas flows within the station and to/from external pipelines. While SoCalGas has managed to keep the main mechanical components of this station operating reliably for close to 60 years, there are many smaller components (20-40 years old) which undermine station reliability through failure. These include aging wiring, pneumatic switches, valves and electronic components subject to temperature extremes associated with desert operation. These failures have increased in recent years and have caused consistent engine start/availability issues. SoCalGas has managed around these failures and related parts availability issues, but believes these failures will accelerate over the next three years and beyond.

Forecast Methodology

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Compressor Station Additions/Replacements Desert Center Compressor Station Controls Upgrade	00315-04
WITNESS	**IN SERVICE DATE**
Ray Stanford	09/30/2013

Cost forecasts were based on completed controls upgrade projects at the following SCG compressor stations: North Needles, South Needles and Kelso.

Schedule
Years one and two of the project will consist of engineering and design as well as the procurement of major devices, while year three will include installation and start up.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE Gas Transmission Compressor Station Additions/Replacements Newberry Springs Lined Evaporation Ponds	**BUDGET NO.** 00315.05
WITNESS Ray Stanford	**IN SERVICE DATE** 06/30/2012

PROJECT COST ($000 in 2009$)	**PRIOR YEARS**	2009	2010	2011	2012	**REMAINING YEARS**	TOTAL
DIRECT LABOR				236	531	0	767
DIRECT NONLABOR				300	2,550	0	2,850
TOTAL DIRECT CAPITAL				536	3,081	0	3,617
COLLECTIBLE				0	0	0	0
NET CAPITAL				536	3,081	0	3,617
FTE				2.5	5.7		8.1

Business Purpose
SoCalGas is proposing to improve the surface impoundment for the disposal and evaporation of brine generated by evaporative cooling towers used to cool discharged gas and jacket water from station compressors.

Physical Description
The proposed improvement includes the construction of two new lined evaporation pond cells designed to handle wastewater discharge from the evaporative cooling towers which is currently being discharged to an unlined evaporation pond and designated irrigation area. Primary and secondary HDPE liners will be installed with a geonet material and inspection pipe between the two liners as a method of monitoring the integrity of the primary liner. Monitoring wells will be installed to monitor the integrity of groundwater. Fencing will be installed to protect station security.

Project Justification
Maintain reliability of the Newberry Springs Compressor Station and meet the Lahontan Region Water Quality Control Board Waste Water discharge compliance requirements.

Forecast Methodology
Cost forecasts are based on completed work for construction of new lined evaporation ponds at the Blythe Compressor Station.

Schedule
Year one will consist of engineering / design and permitting. Year two will include material procurement and construction.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Compressor Station Additions/Replacements Newberry Springs – Three Capstone Backup Generators	00315.06
WITNESS Ray Stanford	**IN SERVICE DATE** 04/30/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				89	0	0	89
DIRECT NONLABOR				1,050	0	0	1,050
TOTAL DIRECT CAPITAL				1,139	0	0	1,139
COLLECTIBLE				0	0	0	0
NET CAPITAL				1,139	0	0	1,139
FTE				1.0	0	0	1.0

Business Purpose

Newberry Springs Compressor Station is one of the most utilized stations we have, compressing natural gas nearly all the time. Loss of the Newberry Springs Compressor Station at the wrong time would have an impact to capacity and jeopardize system integrity. With all the flexibility we have given the market, Gas Operations needs this station to be dependable. The operation of Newberry Springs Compressor Station impacts throughput from South Needles and North Needles Compressor Stations. System modeling has shown that South Needles Compressor Station throughput could be reduced by 200-300 MMcfd if Newberry Springs Compressor Station is down. The Transportation Security Administration (TSA) listed Newberry Springs compressor station as a critical facility.

Physical Description

This project consists of replacing one Waukesha 350 kW electric generator with three natural gas powered 200 kW Capstone micro-turbines housed in a sea container, linked together, and synchronized to provide the required power. This includes fuel supply, controls, and connection to existing 460 VAC power systems.

Project Justification

Newberry Station has three Waukesha 350 kW electric generators that were installed in 1967. All three generators are required to operate the station at full capacity and they have been operating 99% of the time since 2003. Reliability of the three generators has diminished considering their age, replacement parts are not available, the continued high usage, and each of the generator engines were overhauled during the past five years. Major overhauls on the generator engines in the future will be impossible due to the unavailability of parts. Newberry Station throughput capacity would be significantly compromised in the event of a catastrophic failure on one of the generators. This would create an unacceptable strain on the gas transmission system during high demand periods.

Forecast Methodology

Cost forecasts are based on equipment costs estimates provided by the manufacturer.

Schedule

Project is scheduled to begin in March, 2011 and be complete in April, 2011.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Compressor Station Additions/Replacements RICE NESHAP - Compliance Project	00315.07
WITNESS	**IN SERVICE DATE**
Ray Stanford	02/27/2013

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				47	416	1,146	1,609
DIRECT NONLABOR				360	3,172	9,360	12,892
TOTAL DIRECT CAPITAL				407	3,588	10,506	14,501
COLLECTIBLE				0	0	0	0
NET CAPITAL				407	3,588	10,506	14,501
FTE				0.5	4.5	12.5	17.5

Business Purpose

The scope of this project consists of modifying the combustion and emission controls on various engines at SoCalGas Compressor stations in order to comply with revised federal air quality standards. SoCalGas is subject to the National Emission Standard for Hazardous Air Pollutants (NESHAPS) EPA regulation Subpart ZZZZ, which regulates hazardous pollutants from Reciprocating Internal Combustion Engines (RICE). SoCalGas compressor stations in the Mojave air district are also subject to Mojave Desert Air Quality Management District (MDAQMD) Rule 1160, which regulates NOx, CO, and VOC emission limits. Rule 1160 compliance costs are presented in a separate work paper.

Subpart ZZZZ is being revised to expand the engines subject to the rule, and also will require additional source testing for some specific engines. The expansion of engine types goes well beyond typical major emission sources, but also includes combustion engines as small as 50 horsepower. The changes to the regulations will require combustion and emission control technology to be installed on the engines and generators.

Physical Description

Multiple layers of emissions control and combustion technology are required to ensure compliance with the revised rulings. The overall strategy for achieving compliance will be combustion modifications to allow leaner operation of the engines. If the revised rules require lower CO and/or VOC limits, then oxidation catalysts will also be required. Both pre-treatment and after-treatment modifications will need to be made depending one the engine type (i.e. 4 stroke rich burn). The following is a breakdown of what modifications are to be made at specific locations: (see next page)

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Compressor Station Additions/Replacements RICE NESHAP - Compliance Project	00315.07
WITNESS	**IN SERVICE DATE**
Ray Stanford	02/27/2013

Station	Modification
Newberry Springs	PCC, ePCC, NSCR, Oxy Cat, Mon
North Needles	PCC, ePCC,NSCR, Oxy Cat, Mon
South Needles	PCC, ePCC, NSCR, Oxy Cat, MPF, Mon
Adelanto	NSCR, Mon
Kelso	NSCR, Mon
Blythe	NSCR, Mon, Oxy Cat

Station	Modification
Playa del Rey	Mon
Goleta	Mon
Cactus City	NSCR, Mon
Ventura	Mon
Rainbow	Mon

Legend:

MPF:	Medium Pressure Fuel Valve	NSCR	3-Way Catalysts
PCC:	Precombustion Chambers	Oxy Cat:	Oxidation Catalyst
ePCC:	Electronic Combustion Chamber	Mon:	Monitoring and reporting system

Project Justification

As previously mentioned, the air quality rules that govern emission standards are being revised at both the federal and local levels. Subpart ZZZZ aims to reduce hazardous pollutants like Formaldehyde, Acrolein, Benzene, Methanol, and Acetaldehyde. While specific technology is required on the various engines throughout the air districts in order to comply with the Federal and local revised rules, the available technology overlaps to achieve compliance with both rules.

Subpart ZZZZ –RICE NESHAPS:

Currently, only 4 stroke rich burn engines over 500 hp are the only engines subject to the rule. Proposed changes expand the engines subject to the rule to 2 stroke lean burn, 4 stroke lean burn, 4 stroke rich burn, and CI (diesel) engines as small as 50 hp. Other revisions include CO and formaldehyde emission limits for rich burn engines, monitoring to ensure compliance, increased recordkeeping and notifications for initial, performance testing, and compliance testing for all engines over 50 hp.

Forecast Methodology

The modification estimates are based on recent projects and vendor quotes for the specific combustion and after treatment technologies. The overall project costs were developed by indicating what technology on specific engine types was required at the various stations. The individual costs were then added per facility and per year depending on when the revised ruling would take effect per the schedule below. Additional costs were included in the estimates to allow for peripheral and auxiliary systems to be upgraded in order to support the emission devices.

Schedule

Modifications and expenditures are planned to be layered in as the rules get finalized in accordance with the following schedule:

- EPA promulgated Subpart ZZZZ amendments February 2010
- Compression ignited engines (diesel) will be subject to the Subpart ZZZZ in February 2013

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Compressor Station Additions/Replacements RICE NESHAP - Compliance Project	00315.07
WITNESS	**IN SERVICE DATE**
Ray Stanford	02/27/2013

- Spark ignited engines will be subject to the Subpart ZZZZ in August 2013
- Next NESHAP revision to address existing lean burn engines at Major sources will occur in approximately 2012

2011	2012		2013
Blythe (monitoring)	Adelanto	Cactus City	Blythe
Newberry (monitoring	Kelso	Ventura	Newberry Springs
North Needles (monitoring)	Blythe (partial)	Goleta	North Needles
South Needles (monitoring)	Newberry Springs (partial)	Playa del Rey	South Needles
	North Needles (parital)		
	South Needles (partial)		

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Compressor Station Additions/Replacements MOJAVE DESERT AQMD - Rule 1160 – Compliance Project	00315.08
WITNESS Ray Stanford	**IN SERVICE DATE** 02/27/2013

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				110	881	0	991
DIRECT NONLABOR				837	6,714	0	7,551
TOTAL DIRECT CAPITAL				947	7,595	0	8,542
COLLECTIBLE				0	0	0	0
NET CAPITAL				947	7,595	0	8,542
FTE				1.2	9.5	0.0	10.7

Business Purpose

The scope of this project consists of modifying the combustion and emission controls on various engines at SoCalGas Compressor stations in order to comply with local air quality standards, in addition to revised federal standards found in the National Emission Standard for Hazardous Air Pollutants (NESHAPS) EPA regulation Subpart ZZZZ, which regulates hazardous pollutants from Reciprocating Internal Combustion Engines (RICE). SoCalGas compressor stations in the Mojave air district are also subject to Mojave Desert Air Quality Management District (MDAQMD) Rule 1160, which regulates NOx, CO, and VOC emission limits. The cost of compliance with Rule 1160 are presented here.

Rule 1160 will be revised to reduce the NOx, CO, and VOC emission limits for 4 stroke rich burn, 2 stroke lean burn, and 4 stroke lean burn engines. The changes to the regulations will require combustion and emission control technology to be installed on the engines and generators. The changes to the regulations will require combustion and emission control technology to be installed on the engines and generators.

Physical Description

Multiple layers of emissions control and combustion technology are required to ensure compliance with the revised rulings. The overall strategy for achieving compliance will be combustion modifications to allow leaner operation of the engines. If the revised rules require lower CO and/or VOC limits, then oxidation catalysts will also be required. Both pre-treatment and after-treatment modifications will need to be made depending one the engine type (i.e. 4 stroke rich burn). The following is a breakdown of what modifications are to be made at specific locations: (see next page)

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Compressor Station Additions/Replacements MOJAVE DESERT AQMD - Rule 1160 – Compliance Project	00315.08
WITNESS	**IN SERVICE DATE**
Ray Stanford	02/27/2013

Station	Modification
Newberry Springs	AFR, CPM, ION
North Needles	AFR, CPM, ION, PCC
South Needles	AFR, CPM, ION, PCC

Station	Modification
North Needles	AFR
South Needles	AFR

Legend:

AFR: Air Fuel Ratio Control
CPM: Continuous Pressure Monitor
ION: Ion Sensing

Project Justification

As previously mentioned, the air quality rules that govern emission standards are being revised at both the federal and local levels in the Mojave Air District jurisdiction. Rule 1160 reduces NOx, CO, and VOC limits. While specific technology is required on the various engines throughout the air district in order to comply with the revised rules, the available technology overlaps to achieve compliance with both rules.

Mojave Air District Rule 1160:

While the revisions to Rule 1160 are not published yet, MDAQMD will look to other air district rules to define Best Available Retrofit Control Technology (BARCT). Although the current limit on NOx is currently 2 g/BHP-hr lower limits are expected, and additional monitoring will be required. The overall strategy for achieving compliance will be combustion modifications to allow leaner operation of the engines. The resulting impacts to the rule revision consist of the following:

- Combustion modifications for all main compressor units at North and South Needles Stations
- Incremental improvements at Newberry Station
- Catalyst install on all uncontrolled generators: Newberry, Adelanto, and Kelso
- Improvements to South Needles generator catalyst systems
- New compliance monitoring systems
- The need for oxidation catalysts dependant on if CO or VOC increases when NOx reduction is achieved

Forecast Methodology

The modification estimates are based on recent projects and vendor quotes for the specific combustion and after treatment technologies. The overall project costs were developed by indicating what technology on specific engine types was required at the various stations. The individual costs were then added per facility and per year depending on when the revised ruling would take effect per the schedule below. Additional costs were included in the estimates to allow for peripheral and auxiliary systems to be upgraded in order to support the emission devices.

Schedule

Modifications and expenditures are planned to be layered in as the rules get finalized in accordance with the following schedule:

- MDAQMD expects to promulgate amendments to Rule 1160 in 2011 for compliance dates in 2013

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Compressor Station Additions/Replacements MOJAVE DESERT AQMD - Rule 1160 – Compliance Project	00315.08
WITNESS	**IN SERVICE DATE**
Ray Stanford	02/27/2013

2011	2012
North Needles (partial)	Newberry Springs
South Needles (partial)	North Needles
	South Needles

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Cathodic Protection - Blanket	00316.00
WITNESS	**IN SERVICE DATE**
Ray Stanford	Blanket

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR		129	143	108	108	0	488
DIRECT NONLABOR		707	2,271	1,685	1,685	0	6,348
TOTAL DIRECT CAPITAL		836	2,414	1,793	1,793	0	6,835
COLLECTIBLE		0	0	0	0	0	0
NET CAPITAL		836	2,414	1,793	1,793	0	6,835
FTE		1.5	1.5	1.2	1.2	0	5.4

Business Purpose
This Budget Code includes costs associated with the installation of cathodic protection equipment used to preserve the integrity of transmission pipelines by protecting them from external corrosion. These projects are mandated by federal and state minimum pipeline safety regulations, and ensure the maintenance of adequate cathodic protection on company facilities.

Costs recorded and estimated in budget categories 306 and 316 are included in this submission.

Physical Description
Typical expenditures include the replacement of surface anode beds, deep well anodes and/or rectifier systems, installation of new cathodic protection stations, and applying cathodic protection to existing steel mains and service lines. Cathodic protection projects may also include the installation of new remote satellite communication technology which allows for more efficient operation and monitoring of the cathodic protection system.

Project Justification
Application of cathodic protection provides greater system protection against corrosion. It allows SoCalGas to meet Federal and State safety compliance requirements, ensuring reliability of transportation into Southern California market.

Forecast Methodology
Estimates in this work paper are the recorded average of completed projects with similar scope completed within the recent years.

Schedule
This is a blanket project.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Meter &Regulator Station Additions/Replacements - Blanket	0318.0000
WITNESS	**IN SERVICE DATE**
Ray Stanford	Blanket

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR		945	710	342	568		2,565
DIRECT NONLABOR		4,664	3,371	1,607	3,003		12,645
TOTAL DIRECT CAPITAL		5,609	4,081	1,949	3,751		15,390
COLLECTIBLE		0	0	0	0	0	0
NET CAPITAL		5,609	4,081	1,949	3,751		15,390
FTE		10.4	7.6	3.7	6.1		27.8

Business Purpose
This Budget Code includes costs of installing and rebuilding large meter set assemblies (MSAs) for transmission-served customers and pressure limiting stations residing on the gas transmission system. These assets require replacement for three principal reasons: aging, change in use patterns and/or population encroachment, and enhancement of the transmission system to contend with gas quality and capacity issues. The capital work ensures reliable operation of critical transmission assets to the extent that they are not compromised by equipment deployed past its useful life. This includes periodic replacement of local field measurement and control equipment directly linking with Gas Operations SCADA system via remote communications.

This work paper presents recorded and estimated costs in budget codes 308, 318, 328 and 338.

Physical Description
Typical expenditures includes the instrumentation necessary for the metering or regulating of natural gas in connection with transmission operations and, in particular, costs associated with additions or replacements of station piping, valves, regulators, control and communications equipment, shelters and enclosures.

Project Justification
Requested funding includes installation of new meter and regulation equipment associated with operation of the transmission pipeline system. It includes gas meters installed to help manage gas flows and quality on the transmission system, and to provide operating information to gas operations control personnel remotely managing the gas delivery system. Also included in this category are regulating stations used to control and limit gas pressure and the flow of gas within the gas transmission system, such as city gate stations. The installation of this equipment is associated with the safe and reliable local operation of SoCalGas pipelines in conformance with DOT and CPUC requirements for the limiting of pipeline and vessel operating pressures. All pipelines must be operated within their maximum allowable operating pressure parameters, and this equipment, whether for newly-installed pipelines or, where replacement is warranted, ensures this compliance and operating integrity.

Forecast Methodology
The forecast for year 2010 shown here is based on the budgeted amount for projects not qualifying for their own work paper. The amounts shown here for years 2011 and 2012 is the difference between the

PROJECT TITLE	BUDGET NO.
Gas Transmission Meter &Regulator Station Additions/Replacements - Blanket	0318.0000
WITNESS	**IN SERVICE DATE**
Ray Stanford	Blanket

amounts for known projects and a five-year average of recorded spend in these Budget Codes in years 2005-2009.

Schedule
This is a blanket project.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Meter &Regulator Station Additions/Replacements Pisgah Meter Station Improvement Project	00318.01
WITNESS Ray Stanford	**IN SERVICE DATE** 06/30/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			168	0	0	0	168
DIRECT NONLABOR			833	0	0	0	833
TOTAL DIRECT CAPITAL			1,001	0	0	0	1,001
COLLECTIBLE			0	0	0	0	0
NET CAPITAL			1,001	0	0	0	1,001
FTE			1.8	0	0	0	1.8

Business Purpose

Southern California Gas Company (SCG) plans to improve the Pisgah Metering Station by installing another meter run within the established existing station limits. The station is located in the Pisgah area of San Bernardino County, approximately 20 miles east of Newberry Springs north of Highway 40. The station is jointly owned between SCG and Pacific Gas and Electric Company (PG&E) as there is an existing metering station between the companies there.

The purpose of the project is to provide PG&E daily balances for the volumes of gas provided to the Southwest Gas Corporation (SWG) by PG&E on SCG's behalf. Normally, the balancing is accomplished by displacement at other interconnections between SCG and PG&E, however because gas scheduling may not always allow for daily deliveries at other existing interconnection locations, another point of delivery is required and Pisgah Station was identified. The project is planned in accordance with a new wholesale transportation agreement between SWG and SCG, and a gas delivery exchange agreement between PG&E and SCG. Both agreements, as well as the required capital improvements to the Pisgah Station have been reviewed and approved by the California Public Utilities Commission (CPUC) under decision 09-10-036 on October 29, 2009.

Physical Description

The work consists of installing a new 4-inch meter run tied into SCG's and PG&E's crossover pipeline within Pisgah Station. Engineering designs are currently being developed, however it's anticipated that the following will be installed:

- One (1) 4" Turbine Meter with a Total Flow computer
- Three (3) -2" control valves with a Becker Digital Natural Gas Positioner (DNGP) System
- Four (4) -4" ball valves (2 tap valves, and 2 valves on the meter run itself)
- Pre-fab fiberglass shed 6' x 6' x 7' w/ explosion proof AC unit. Building will have a concrete slab foundation
- Meter run will also include one (1) 4" dry gas PECO filter upstream of the regulation and meter.
- One (1) filter separator upstream of metering facilities.

Project Justification

SCG reviewed other existing interconnects throughout its service territory, however the Pisgah Station was selected as the preferred alternative because it provided the operational parameters required to effectuate deliveries between the companies. Further, because of the existing station's size, modifications

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Meter &Regulator Station Additions/Replacements Pisgah Meter Station Improvement Project	00318.01
WITNESS	**IN SERVICE DATE**
Ray Stanford	06/30/2010

can be made inside the fenced in area, resulting in far fewer environmental impacts. The disturbance associated with tying the new meter station piping into SCG's and PG&E's pipeline is very minimal, and more importantly, it completely avoids disturbance outside of the fenced area.

Forecast Methodology

Estimates in this work paper are based on projects with similar scope completed within recent years.

Schedule

The regulatory approval of the project requires that the station be in service by November 1, 2010. It is expected to take approximately four to six weeks to complete the activities necessary to construct the new meter station and crews will work 10-hour days, 5 days a week to complete the work. Work will commence by June, pending the receipt of all necessary permits and authorizations.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven L 7038 Install Transmission pressure regulation station	00318.02
WITNESS Ray Stanford	**IN SERVICE DATE** 01/31/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				27	9		36
DIRECT NONLABOR				1,323	441		1,764
TOTAL DIRECT CAPITAL				1,350	450		1,800
COLLECTIBLE	(0)	(0)	(0)	(0)	(0)	(0)	(0)
NET CAPITAL				1,350	450		1,800
FTE				0.3	0.1		0.4

Business Purpose

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 (PSIA 2002) was signed into law, and subsequently 49 C.F.R. Part 192 Subpart O was published. The final rule was effective January 14, 2004. Under this rule, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risk posed by these threats, assess the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline incidents can occur.

This project has been developed to address the regulatory requirements set forth by the implementation of PSIA 2002. All DOT transmission pipeline work generated to address these regulatory requirements will be captured in Budget Category (BC) 312 and (BC) 276 for distribution pipeline related work.

Physical Description

In certain situations due to the pipe condition, location or environment it may be more economical to replace a pipeline with new pipe operating at lower stress which would not require baseline assessment or repeated re-assessment. This is often the case with short pipe segments and cross over piping. In those situations a pipeline may be replaced in lieu of retrofitting for internal inspection, if the construction can be implemented within the DOT mandated assessment schedule. Alternatively for some longer pipelines pressure reducing facilities (regulation station) may be installed to operate the pipeline at lower pressure and stress levels in lieu of repeated inspection per PSIA 2002.

Project Description

Install Transmission pressure reduction station, and replace 1,000 feet of 12" pipe at Glen Oaks blvd and Paxton Ave, and install new Distribution pressure regulation station at Bradley and Paxton Ave in Pacoima, California.

Project Justification

All DOT Transmission Pipeline Integrity baseline assessments are in response to the Federal Pipeline Safety Improvement Act of 2002 and are required to comply with the subsequent rule making. Capital repairs and replacements are constructed in accordance with 49 CFR 192, ASME B31.8, and other codes

PROJECT TITLE	BUDGET NO.
Gas Transmission Pipeline Replacements / Externally Driven L 7038 Install Transmission pressure regulation station	00318.02
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2012

and standards as appropriate.

<u>Forecast Methodology</u>

Cost forecasts are based on completed work from similar projects involving similar pipeline replacement and facility installation.

Often the work to complete replacement of a pipeline, in order to comply with PSIA 2002, spans more than one year. Based on experience with previous pipeline replacements, project expenditures are forecast over a two year period.

Typical Schedule	Year 1	Year 2	Year 3	Sum
	% Work	% Work	% Work	
Install Pressure reduction facilities with short pipe section replacement	75%	25%		100%

<u>Schedule</u>

The completed capital portion of the project, referred to as in-service date for this project is: 01/31/2012.

The initial assessment of all DOT defined transmission pipelines is scheduled in the SoCalGas and SDG&E Baseline Assessment Plan (BAP). The BAP is a requirement component of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published rule requiring an "integrity management" program for natural gas transmission pipelines.

The plan ranks the pipelines according to risks and develops an inspection schedule by year for each of the DOT defined transmission pipelines operated by SCG or SDG&E. Based upon the inspection year and type of assessment, a project will be scheduled for inspection. If the line is to be internally inspected, a four year project plan is developed where:

Year 1: Planning work for replacement. A detailed study of the pipeline components is created. A plan is developed to remove/replace all identified sections of the pipeline. Permits are acquired, Materials are ordered and the job is awarded for construction to a contractor. Construction is started and completed depending on size and duration of job.

Year 2: When construction spans more than one year the remaining work is completed and pipeline is placed in service.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Rebuild Gas Meter and Regulator Station – Alamitos Generating Plant, Long Beach, CA	00318.03
WITNESS	IN SERVICE DATE
Ray Stanford	01/31/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR				177	30	0	207
DIRECT NONLABOR				1,050	475	0	1,525
TOTAL DIRECT CAPITAL				1227	505	0	1,732
COLLECTIBLE				0	0	0	0
NET CAPITAL				1,227	505	0	1,732
FTE				1.9	0.3	0	2.2

Business Purpose

Improve the measurement and gas pressure regulating control system reliability and metering accuracy at one of SCG's largest Electrical Generating customer sites. Current equipment ranges in age from 20-50 years and in some instances has exhibited functional problems and cannot be successfully maintained and operated to current gas industry standards for the metering type employed due to the inaccessibility of buried metering runs. Measurement accuracy improvement under normal operation expected to be 0.6% on average with upgrade. Improve the gas pressure delivery to the customer by upsizing gas regulators to contend with minimum inlet pressures migrating below the facility design conditions which have required emergency changes in gas regulator pressure set-points to sustain plant operation. The current meter set was designed and installed based on stable plant loading profile over 50 years ago - and in an era where design standards, acceptable maintenance practices and the value of gas was much different than today. Changes in plant operation have been dramatic since electric deregulation. The plant cycles more frequently and experiences much wider load variation than the design conditions of 50 years ago. This change has the current equipment operating on the outside original specification. The age of equipment has also become a factor in operational reliability. There are antiquated run switching valves which experience mechanical binding, and equipment for which there are simply no longer replacement parts - creating potential for sustained customer load loss. The addition of a gas filter/separator to improve the quality of measurement and prevent gas regulator/measurement malfunction, and possible customer loss is also part of this upgrade - this site has been experiencing more liquid entrainment in delivered gas due to upstream pipeline integrity pigging activity in recent years. A new filter separator will minimize the future impact of such activity on meter accuracy and customer equipment operation. This work will also serve as pre-emptive removal of apparatus which has experienced some corrosion over a 50 year life and which is trending toward, but not quite at, required removal condition.

Newer ultrasonic meter technology proposed for installation will require less frequent scheduled and unscheduled maintenance and also provides diagnostic alarming and communication to help determine when measurement accuracy has shifted at a customer site. This is a substantial upgrade from the existing mechanical metering system-benefiting the customer with improved meter accuracy.

Physical Description

Design/Install new Meter Set Assembly as follows:

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Rebuild Gas Meter and Regulator Station – Alamitos Generating Plant, Long Beach, CA	00318.03
WITNESS	**IN SERVICE DATE**
Ray Stanford	01/31/2012

- One or two AGA compliant Ultrasonic meters to replace large two orifice meter and problematic turbine meter run switching;
- New gas regulators capable of stable pressure control at reduced inlet pressure and more dynamic plant operation;
- New gas filter and separator to contend with liquids more prevalent on the system area as a result of past and future pigging activities associate with pipeline integrity;
- New configuration to bring meter tubes above ground to support routine cleaning consistent with AGA standards for large metering systems.

Project Justification

Estimated base annual measurement accuracy improvement: 0.6% of all volumes delivered. Reduce measurement uncertainty by 72 MMcf in each calendar year. Equivalent gas costs associated with this improvement at $5 per MMBtu is $360,000 per year under normal operation. Metering at the site to match the type employed at all new SCG and SDGE large electrical generating plants.

SoCalGas believes it prudent to upgrade this important electric generating customer to state of the art and reliable measurement equipment specific to their contemporary load conditions and in consideration of risks associated with customer loss. Risk of unscheduled customer shutdown reduces by reducing liquid slugs and filtering gas prior to regulator station inlet.

Forecast Methodology

Measurement improvement based on SCG and industry testing of large metering as-found in field applications; and in the reduced uncertainty associated with ultrasonic meters over orifice metering operating over a moderate flow range.

Risk of customer shutdown based on prior occurrence of erratic regulator operation and near failure based on low inlet pressures and or liquids. Both of these issues will be addressed with this capital improvement.

Schedule

This work is exceedingly difficult to schedule at this customer site due to their operational profile, contractual obligations, and the stakes associated with extension of any shutdown beyond plan. As of this writing the preliminary engineering redesign of this facility is underway. The physical work is planned to be completed and placed in-service by February of 2012, pending a window for such work being negotiated with the customer.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Rebuild gas Meter and Regulator station – Exxon Mobil Refinery	00318.04
WITNESS	**IN SERVICE DATE**
Ray Stanford	08/31/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			177	0	0	0	177
DIRECT NONLABOR			1,050	0	0	0	1,050
TOTAL DIRECT CAPITAL			1,227	0	0	0	1,227
COLLECTIBLE			0	0	0	0	0
NET CAPITAL			1,227	0	0	0	1,227
FTE			1.9	0	0	0	1.9

Business Purpose

Improve measurement and gas pressure regulating control system reliability, maintenance accessibility, and metering accuracy at one of SCG's largest customer sites. Current equipment ranges in age from 20-30 years and in some instances has exhibited functional problems due to the type of technology employed. This same equipment has caused customer billing adjustment in excess of 3 Bcf at other SCG locations due to intermittent failure. Measurement accuracy improvement under normal operation is expected to be 0.6% on average. Improve gas pressure delivery to the customer by upsizing gas regulators to contend with minimum inlet pressures migrating below the facility design conditions over the past 10 years, creating potential for customer load loss. The addition of a gas filter/separator to improve the quality of measurement and prevent gas regulator malfunction and possible customer loss is also part of this upgrade.

Physical Description

Install new MSA as follows:

- Single Ultrasonic meter to replace large orifice meter and problematic turbine meter run switching;
- New gas regulators capable of stable pressure control at reduced inlet pressure and more dynamic plant operation;
- New gas filter and separator to contend with liquids more prevalent on the system area as a result of past and future pigging activities associate with pipeline integrity;
- Reconfigure plant layout to reduce risk of employee injury through improved ergonomics.

Project Justification

Estimated base annual measurement accuracy improvement: 0.6% of all volumes delivered. Reduce measurement uncertainty by 60 MMcf in each calendar year. Equivalent gas costs associated with this improvement at $5 per MMBtu is $300,000 per year under normal operation.

The type of specific metering at this site is of antiquated design, and similar meters are being removed where practical by SCG after proving to be the root cause for some large billing adjustments and measurement errors due to mechanical binding. SoCalGas believes it prudent to upgrade this important fuel-producing customer to state of the art and reliable measurement equipment specific to their contemporary load conditions and in consideration of risks associated with customer loss. Risk of

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Rebuild gas Meter and Regulator station – Exxon Mobil Refinery	00318.04
WITNESS	**IN SERVICE DATE**
Ray Stanford	08/31/2010

unscheduled customer shutdown reduces by reducing liquid slugs and filtering gas prior to regulator station inlet. Newer technology will require less frequent scheduled and unscheduled maintenance at a site which is difficult to access due to security reasons and cannot easily be shut down for major repairs. Moreover, this upgrade is preferable to escalation of unplanned failures.

Forecast Methodology

Measurement improvement based on SCG and industry testing of large metering as-found in field applications; and in the reduced uncertainty associated with ultrasonic meters over orifice metering operating over a moderate flow range.

Risk of failure for type of meter is based on two SCG meter failures of this type-out of approximately 20 total.

Risk of customer shutdown based on prior occurrence of erratic regulator operation and near failure based on low inlet pressures and or liquids. Both of these issues will be addressed with this capital improvement.

Schedule

This work is exceedingly difficult to schedule at this customer site due to their operational profile and the stakes associated with extension of any shutdown beyond plan. As of this writing the engineering redesign of this facility was complete. The physical work is planned to be complete and placed in-service by August of 2010, pending a window for such work being negotiated with the customer.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Tesoro Refinery New Meter Set Assembly (MSA) Project	00318.05
WITNESS	**IN SERVICE DATE**
Ray Stanford	06/30/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR			242	0	0	0	242
DIRECT NONLABOR			967	0	0	0	967
TOTAL DIRECT CAPITAL			1,209	0	0	0	1,209
COLLECTIBLE			(1,209)	(0)	(0)	(0)	(1,209)
NET CAPITAL			0	0	0	0	0
FTE			2.6	0	0	0	2.6

Business Purpose

This project consists of design and construction of a new Meter Set Assembly (MSA) to deliver up to 35 million cubic feet per day (MMCFD) of natural gas supply to a refinery operated by Tesoro Marketing and Refining Company in Wilmington, California. The new MSA will supply a new co-generating plant proposed to replace the old existing one at the location. It will additionally power two (2) new boilers that will replace the existing ones which are less efficient.

Physical Description

Project work includes design, engineering and installation of MSA, instruments and equipment including, electrical and communication service lines. Approximately 250 linear feet of a 10-inch diameter high pressure service line will be installed from the MSA to connect to existing gas transmission pipeline (Line 325).

Project Justification

Tesoro Marketing and Refining Company are investing more than three hundred million for installing new boilers and constructing a new co-generating plant at the location. The project is 100% collectable.

Forecast Methodology

Estimated cost is based on actual expenditures of the recently completed projects, which were of similar size and scope. Cost estimate also has contingencies for unexpected change with respect to materials and labor indirect costs.

Schedule

Project construction work is expected to begin in the second quarter 2010 and conclude by June 30, 2010.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Blythe Energy MSA Project	00318.06
WITNESS	IN SERVICE DATE
Ray Stanford	11/30/2010

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR	18	182	39	0	0	0	239
DIRECT NONLABOR	0	933	1,220	0	0	0	2,153
TOTAL DIRECT CAPITAL	18	1,115	1,259	0	0	0	2,392
COLLECTIBLE	(18)	(1,115)	(1,259)	0	0	0	(2,392)
NET CAPITAL	0	0	0	0	0	0	0
FTE	0.2	2.0	0.4	0	0	0	2.6

Business Purpose
This project is a required to provide a supply pipeline and MSA for the Blythe Energy 500 MW electric generating station located in Blythe, California. The customer was previously being served by EPNG through a 20-inch diameter pipeline owned by Blythe Energy.

Physical Description
The project consists of fabricating and installing a complete large GEMS Meter Set Assembly (MSA) and installing approximately 2,100 feet of associated pipeline. The MSA is located within SCG's Blythe Compressor Station. The MSA is connected to an existing 20-inch diameter pipeline owned and operated by Blythe Energy.

Project Justification
Blythe Energy has a new 10-year contract to supply electrical power to the Southern California Edison Company. This agreement requires that delivery of natural gas used to generate electricity must be provided by a California based company. This project is 100% collectible from Blythe Energy.

Forecast Methodology
Estimated cost was determined based on the cost to fabricate, install and commission a similarly sized Large GEMS MSA. The estimated cost to install required pipeline, valves and associated appurtenances was based on an analysis of the tasks, material costs provided by suppliers and actual costs for similar work.

Schedule
Engineering and design was started in the 3rd quarter 2008 and the MSA should be complete by Nov, 2010 or earlier.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission Auxiliary Equipment & Infrastructure - Blanket	00319.00
WITNESS	**IN SERVICE DATE**
Ray Stanford	Blanket

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR		221	100	83	83		487
DIRECT NONLABOR		644	782	1,568	1,568		4,562
TOTAL DIRECT CAPITAL		865	882	1,651	1,651		5,049
COLLECTIBLE		0	0	0	0	0	0
NET CAPITAL		865	882	1,651	1,651		5,049
FTE		2.6	1.1	0.9	0.9		5.5

Business Purpose
Requested funding in this category includes new installations or upgrades of aging M&R station and pipeline system control and telemetry systems which link with and provide information to, but are not a direct part of SoCalGas centralized SCADA computer system. Assets which reside on the upstream side of the remote communications network to SoCalGas central SCADA system are defined and requested under plant category 309/319. SoCalGas has over pipeline 200 locations where local controls interface with its operations control center/central SCADA system. SoCalGas installs and/or modifies 10-20 such facilities in a typical year.

This work paper includes recorded and estimated costs in budget codes 309, 319 and 339.

Physical Description
Included are local controls and communication devices such as programmable logic controllers (PLCs), pressure transmitters, UPS systems, temperature probes, gas quality remote sensors, and communication interfaces/technologies. This equipment is used to control the flow of gas in pipelines, valves and regulator stations both locally and through the initiation of remote commands from central SCADA system.

Project Justification
This capital work ensures reliable operation of critical transmission assets to the extent that they are not compromised by equipment deployed past its useful life. These assets require replacement due to aging, change in use patterns, and enhancement of the transmission system to contend with gas quality and capacity issues.

Forecast Methodology
Forecast for 2010 is based on the 2010 budget for these Budget Categories. 2011 and 2012 are five-year averages of recorded costs in the years 2005-2009.

Schedule
This is a blanket project and as such, projects will be worked throughout the indicated years.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Sustainable SoCal Program	00399.00
WITNESS	**IN SERVICE DATE**
Ray Stanford	07/31/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR					422	422	844
DIRECT NONLABOR					10,850	10,850	21,700
TOTAL DIRECT CAPITAL					11,272	11,272	22,544
COLLECTIBLE					0	0	0
NET CAPITAL					11,272	11,272	22,544
FTE					4.8	4.8	9.6

Business Purpose

SoCalGas proposes to install four biogas conditioning units at certain customer sites for the purpose of capturing 'raw biogas' and converting it to pipeline quality biogas (biomethane). SoCalGas will accept the producer’s raw biogas, clean it to pipeline quality and inject it into the natural gas pipeline system.

SCG can leverage its long experience in natural gas processing and deep knowledge of gas processing technology to take on a leadership role to impel the biogas market forward in support of the States objective to significantly reduce greenhouse gasses (GHGs) as directed in AB 32 and S-06-06. The Sustainable SoCal Program makes a step forward in that direction by giving small to medium biogas producers an option other than flaring gas to the atmosphere, while at the same time providing various societal and cost avoidance benefits to SCG ratepayers.

SCG will use this gas for company facilities use and to fuel CNG fleet vehicles. At this production volume, the total gas produced by the four proposed installations will generate enough gas to cover approximately 75% - 80% of company and fleet uses. In addition, this gas volume will result in approximately $130,000 annually in cost avoidance due to GHG credits. This model ensures that the costs and benefits are equally shared by all customer classes.

Physical Description

SoCalGas’ primary role in this project will be to design, install and operate biogas conditioning systems at biogas producer sites having volumes in the range of 200 to 600 scfm. Each biogas conditioning system at a producer site will entail a one time capital investment to cover the costs of both the biogas conditioning systems and interconnection equipment/facilities. SoCalGas will consider a variety of proven biogas conditioning equipment vendors and technologies for the Sustainable SoCal Program. Such technologies may include but not be limited to: Pressure Swing Absorption (PSA), Thermal Swing Absorption (TSA) and Amine Gas Treating. All of the producer biogas will be cleaned to pipeline quality and meet the gas quality specifications as set forth in Rule No. 30, Section I.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE Sustainable SoCal Program	BUDGET NO. 00399.00
WITNESS Ray Stanford	IN SERVICE DATE 07/31/2012

Project Justification

SCG estimates the biogas market potential for waste water treatment facilities in SCG and SDG&E service territories to be approximately 20 million standard cubic feet per day (MMscfd), and the majority of this biogas is currently an untapped source of sustainable energy. Many small to mid size biogas producers find it more economical to flare their biogas into the atmosphere, while emitting many pollutants, particulate matter and toxins into the environment in the process. The successful implementation of this project will allow small to mid size biogas producers to avoid flaring, and allowing Californians to benefit from cleaner air. The project will act as a reference framework and model across the SCG service territory to capture and utilize sources of biogas, and will support several important State goals:

- Meets the objectives of AB 32 by providing California and its ratepayers with significant environmental and economic benefits of GHG emissions reduction
- Meets the objectives of State Executive Order S-06-06, which directs state agencies to promote instate bioenergy production and use. S-06-06 established the instate production goals of a minimum of 20 percent of its consumed biofuels by 2010, 40 percent by 2020, and 75 percent by 2050
- Meets the objectives of the Memorandum of Understanding (dated June 15, 2006) between the State of California and the Kingdom of Sweden where the two governments and their related industries pledged to work together to develop bioenergy, with a particular emphasis on biomethane.

For further details on the policy and justification for this project, please refer to the prepared testimony of witness Gillian A. Wright.

Forecast Methodology

Estimated conditioning cost is based upon information provided by biogas equipment vendors. Also included is the estimated cost of interconnecting to a SoCal Gas natural gas pipeline. For a detailed breakdown of the capital cost per site, please refer to Attachment A of this work paper.

Schedule

The Sustainable SoCal Program plans to install the first two biogas conditioning systems in Q3 of 2012. To meet this timeline, SCG plans to identify and execute contracts with two biogas producers, select the biogas equipment vendors, begin the interconnection process, and complete the required permitting pre-work prior to the end of 2011. One additional installation is planned for year 2013 and another for year 2014.

PROJECT TITLE	BUDGET NO.
Sustainable SoCal Program	00399.00
WITNESS	**IN SERVICE DATE**
Ray Stanford	07/31/2012

ATTACHMENT A – COST BREAKDOWN

Cost Summary

Equipment Installation Costs	Cost
Company Labor	$ -
Non-Labor	$ 3,712,000
Subtotal	$ 3,712,000

Interconnection Costs	
Company Labor	$ 211,000
Non-Labor	$ 1,713,000
Subtotal	$ 1,924,000
Total Direct Cost	$ 5,636,000

Cost Detail

	SCFM	SCFD
RAWGAS FLOW	300	432,000

EQUIPMENT INSTALLATION COSTS

Equipment	Cost
Conditioning Equipment Cost	$ 1,175,000

Intallation Costs	Cost
Guild Equipment Installation	$ 69,000
Civil (site preparation, product gas line)	$ 659,000
Structural (support platforms, stairs)	$ 19,000
Mechanical (piping, misc. equip.)	$ 560,000
Electrical (power, instrumentation)	$ 503,000
Area Lighting	$ 6,000
Spare Parts	$ 12,000
Ambient Air Monitors	$ 62,000
Sound attenuation	$ 79,000
Subtotal	$ 1,969,000

TOTAL INSTALLATION COSTS	$ 3,144,000

OTHER COSTS	Cost
Permits/CM/General	$ 157,000
Engineering	$ 297,000
Insurance	$ 114,000
TOTAL OTHER COSTS	$ 568,000

INTERCONNECTION COSTS

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Sustainable SoCal Program	00399.00
WITNESS	**IN SERVICE DATE**
Ray Stanford	07/31/2012

Point of Receipt	**Cost**	**FTE**
Company Labor	$ 97,000	1.1
Contract Labor	$ 296,000	
Material	$ 419,000	
Miscellaneous	$ 86,000	
Subtotal	$ 898,000	

Pipeline Extension to Utility Pipeline	**Cost**	**FTE**
Company Labor	$ 114,000	1.3
Contract Labor	$ 676,000	
Material	$ 189,000	
Miscellaneous	$ 47,000	
Subtotal	$ 1,026,000	
TOTAL INTERCONNECTION COST	$ 1,924,000	

	Cost
TOTAL DIRECT CAPITAL COST PER SITE	$ 5,636,000

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Buffer Land purchases for Air Quality compliance purposes	00617.01
WITNESS	IN SERVICE DATE
Ray Stanford	12/31/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR		0	0	0	0	0	0
DIRECT NONLABOR		0	0	4,000	2,000		6,000
TOTAL DIRECT CAPITAL		0	0	4,000	2,000		6,000
COLLECTIBLE		0	0	0	0	0	0
NET CAPITAL		0	0	4,000	2,000		6,000
FTE		0	0	0	0	0	0

Business Purpose
Provide the means to buy properties adjacent to remote compressor station sites while prices are reasonable. Eliminates future conflicts with neighbors due to noise, odors, and emissions. In some cases may be an economical alternative to emissions projects and HRA (Health Risk Assessments). Also may provide room for future expansion if necessary..

Physical Description
Multiple-acre purchases of land adjacent to compressor stations at Blythe, Newberry Springs and North Needles.

Project Justification
While land prices are low, this is an opportunity to prevent future conflicts with neighbors due to noise, odors, and emissions. In some cases may be an economical alternative to emissions projects and HRA's. Also may provide room for future expansion if necessary.

Health Risk Assessments (HRAs) are independent of air districts' local attainment status. Facilities are subject to the Clean Air Act if they manufacture, formulate, use, or release a listed substance and either emits 10 tons or more per year of criteria pollutants (total organic gases, particulate matter, nitrogen oxides, or sulfur oxides) or emits less than 10 tons per year of criteria pollutants and are listed by the state as a type of facility subject to emission inventory requirements.

At Ventura SCG was mandated by the Air District to perform a HRA which was very onerous, involved public notifications, and the research and development of special exhaust catalysts. Fortunately we were able to mitigate and not have to re-power or go with electric drivers. At other stations, the results could be different. Air Districts can request HRAs be performed at subject-to-the-Act facilities if they feel political, environmental, or public pressure.

Blythe is subject to the Act. The farmland parcel down wind of Blythe would be a very good strategic purchase.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Buffer Land purchases for Air Quality compliance purposes	00617.01
WITNESS	**IN SERVICE DATE**
Ray Stanford	12/31/2012

Forecast Methodology

Based on estimates of acreage required and expected prices per acre in the 2011-2012 time frame. Prices are expected to approximate an average of $2MM per site.

Schedule

Make two purchases in 2011 and one in 2012. Complete all transactions by the end of 2012.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission – Pipeline Land Rights – Coastal Region Conservation Program – Land purchases for mitigation purposes	00617.02
WITNESS	**IN SERVICE DATE**
Ray Stanford	06/30/2012

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR					0.0		0.0
DIRECT NONLABOR					6,300		6,300
TOTAL DIRECT CAPITAL					6,300		6,300
COLLECTIBLE							
NET CAPITAL					6,300		6,300
FTE					0.0		0.0

Business Purpose

Southern California Gas Company (SoCalGas) is currently developing the Coastal Region Conservation Program (CRCP) that will serve as an incidental take permit application under section 10 of the federal Endangered Species Act and section 2081of the state Fish and Game Code for operation and maintenance activities and limited new construction. SoCalGas will propose a 50-year permit.

Physical Description

The CRCP will prescribe the avoidance, minimization and mitigation measures for approximately 150 special status species with the potential to occur within the CRCP Plan Area ("Covered Species"). The Plan Area will cover approximately 8,656,707 acres across seven counties: Los Angeles, Orange, Riverside, San Bernardino, San Luis Obispo, Santa Barbara, and Ventura.

Project Justification

Based on an analysis of documented activities that took place between 2003 and 2007, SoCalGas has estimated that approximately 150 acres of suitable habitat for one or more of the Covered Species would be impacted every five years, 135 acres of which would be temporarily impacted and 15 acres permanently impacted. These impacts would correspond to five-year "caps," which would never be exceeded for the life of the permit.

SoCalGas anticipates offering the wildlife agencies (i.e., the U.S. Fish and Wildlife Service and the California Department of Fish and Game) the compensatory mitigation up-front, prior to actual impacts, then repeating the cycle every five years for the duration of the permit. Should actual impacts be less than the estimated 150 acres, the remaining mitigation credits would rollover to the next 5-year cycle.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission – Pipeline Land Rights – Coastal Region Conservation Program – Land purchases for mitigation purposes	00617.02
WITNESS	**IN SERVICE DATE**
Ray Stanford	06/30/2012

Forecast Methodology

Based on typical mitigation ratios to offset these impacts and current costs associated with obtaining compensatory mitigation credits (primarily via the purchase of conservation lands), SoCalGas has estimated that the mitigation cost required to offset the first five years of impacts would total approximately $6,300,000 per the following estimate.

Impact Type	5-Year Impacts (acres)	Mitigation Ratio	Mitigation (acres)	Mitigation Cost[1] $56,000/Acre
Permanent	15	3:1	45	2,520,000
Temporary	135	0.5:1	67.5	3,780,000
Total	150	-	112.5	**6,300,000**

Schedule

Purchase 150 acres of eligible mitigation land during the first half of 2012.

[1] Based on averaging the cost-per-acre of the following: (1) Mountains Restoration Trust $125,000/acre for riparian/wetlands credits, Los Angeles County; (2) Ojai Valley Land Conservancy $175,000/acre for riparian restoration/preservation, Los Angeles County; (3) Copper Creek North and South, Los Angeles County $30,000 per acre ($9,000,000 for 300 acres); (4) Rancho Serrano, San Luis Obispo County $5,245/acre ($3,750,000 for 715 acres); (5) 2000 Goodenough Road, Ventura County $12,803/acre ($16,900,000 for 1,320 acres); (6) Santa Maria-Orcutt, Santa Barbara County $2,375/acre ($95,000 for 40 acres); (7) Carpinteria, Santa Barbara County $9,878/acre ($2,925,000 for 296.1 acres); and (8) La Habra Heights, Orange County $88,954/acre ($1,200,000 for 13.49 acres).

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission – EAC – Laboratory Capital Tools - Blanket	00730.00
WITNESS	**IN SERVICE DATE**
Ray Stanford	Blanket

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR		0	0	0	0		0
DIRECT NONLABOR		250	265	935	295		1,745
TOTAL DIRECT CAPITAL		250	265	935	295		1,745
COLLECTIBLE		0	0	0	0		0
NET CAPITAL		250	265	935	295		1,745
FTE		0	0	0	0		0

Business Purpose
Equip the Engineering Analysis Center with modern, state-of-the-art laboratory equipment necessary to maintain the Company's ability to perform necessary analysis and evaluation of materials, emissions and technology.

Physical Description
Regulations are already in process requiring equipment upgrades for both pipeline and engine monitoring. Equipment replacement schedules are developed based on equipment life and past practices thus requiring purchase of new equipment. Laboratory-grade equipment will continue to evolve and become more costly.

Project Justification
Proposed new requirements found in the uncapped sectors of AB 32 and EPA's Subpart W "Mandatory Reporting" require enhanced leak detection and measurement of fugitive methane emissions. EPA's Subpart W specifically will require direct measurement for certain equipment using optical imaging instruments for emissions detection and high-volume samplers for emissions measurement. Proposed as required tools are optical imaging devices that cost approximately $100K each and high-volume samplers that cost approximately $30,000 each. The Engineering Laboratory proposes to purchase four optical imaging devices and nine high-volume samplers in 2011.

Replacing antiquated equipment with equipment upgrades is necessary to maintain production and performance. The EAC annual capital tool account usually covers general laboratory equipment that have a service life of 5 to 7 years. These types of equipment include, but are not limited to, moisture probes/analyzers, chromatographic controllers, combustible gas analyzers, various calibration standards, data acquisition equipment, specialty detectors/valves/regulators and other laboratory grade equipment.

Forecast Methodology
Forecast for 2010 is based on expected purchases in 2010. 2011 is based on a five-year average plus costs for new equipment related to proposed new Greenhouse Gas Emissions rules. 2012 is the five-years average of recorded purchases in years 2005-2009.

Schedule

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission – EAC – Laboratory Capital Tools - Blanket	00730.00
WITNESS	**IN SERVICE DATE**
Ray Stanford	Blanket

This is a Blanket Category

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Gas Transmission & Storage – Capital Tools - Blanket	00736.00
WITNESS	**IN SERVICE DATE**
Ray Stanford	Blanket

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR		0	0	0	0		0
DIRECT NONLABOR		826	307	307	307		1,747
TOTAL DIRECT CAPITAL		826	307	307	307		1,747
COLLECTIBLE		0	0	0	0	0	0
NET CAPITAL		826	307	307	307		1,747
FTE		0	0	0	0		0

Business Purpose
Acquire and replace Captial Tools used on a daily basis by the operating people of Transmission and Storage.

Physical Description
Hand tools, Volt/Amp Meters, GPS receivers, etc.

Project Justification
Purchases are mostly to replace old, worn or damaged tools used in the field.

Forecast Methodology
Entirely based on the five-year average of purchases made during the time period 2005-2009.

Schedule
This is a blanket budget.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Capital Reassignment Pool – Storage – Blanket	001001.00
WITNESS	**IN SERVICE DATE**
Ray Stanford	Blanket

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR		265	240	278	335		1118
DIRECT NONLABOR		0	0	0	0		0
TOTAL DIRECT CAPITAL		265	240	278	335		1118
COLLECTIBLE		0	0	0	0		0
NET CAPITAL		265	240	278	335		1118
FTE		2.2	2.6	3.0	3.6		11.4

Business Purpose
Provide a pool for Supervision & Engineering (S&E) charges that will be reassigned to the various budget categories on a direct basis. Charges reside in this BC temporarily and are reassigned on a monthly basis.

Physical Description
Overhead charges stemming from labor spend on capital projects and reasigned to Capital budget categories specific to the Storage activity.

Project Justification
Continues an established accounting procedure for making charges for certain overheads, on a direct cost basis to Storage's budget categories.

Forecast Methodology
Based on a five-year average of recorded expendatures in years 2005-2009 and adjusted for planed levels of labor charges expected in the remaining budget categories for Transmission and Storage.

Schedule
This is a blanket budget.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Capital Reassignment Pool – S&E - Transmission – Blanket	001002.00
WITNESS	**IN SERVICE DATE**
Ray Stanford	Blanket

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR		871	880	1,019	1,229		3,999
DIRECT NONLABOR		23	23	26	32		104
TOTAL DIRECT CAPITAL		894	903	1,045	1,261		4,103
COLLECTIBLE		0	0	0	0		0
NET CAPITAL		894	903	1,045	1,261		4,103
FTE		9.2	9.5	11.0	13.2		42.9

Business Purpose
Provide a pool for Supervision & Engineering (S&E) charges that will be reassigned to the various budget categories on a direct basis. Charges reside in this Budget Category temporarily and are reassigned on a monthly basis.

Physical Description
Overhead charges stemming from labor spend on capital projects and reasigned to Capital budget categories specific to the Transmission activity.

Project Justification
Continues an established accounting procedure for making charges for certain overheads, on a direct cost basis to Transmission's budget categories.

Forecast Methodology
Based on a five-year average of recorded expendatures in years 2005-2009 and adjusted for planed levels of labor charges expected in the remaining budget categories for Transmission and Storage.

Schedule
This is a blanket budget.

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Coastal Region Conservation Program – SCG allocation	01100.00
WITNESS	**IN SERVICE DATE**
Ray Stanford	09/30/2011

PROJECT COST ($000 in 2009$)	PRIOR YEARS	2009	2010	2011	2012	REMAINING YEARS	TOTAL
DIRECT LABOR	70	24	91	68			253
DIRECT NONLABOR	859	96	703	527			2,185
TOTAL DIRECT CAPITAL	929	120	795	596			2,440
COLLECTIBLE							
NET CAPITAL							
FTE	0.8	0.3	1.0	0.7			2.8

Business Purpose

The purpose of the Coastal Region Conservation Program (CRCP) is to obtain long-term State and Federal authorization under Endangered Species laws for routine SCG operations and maintenance activities in the counties of San Luis Obispo, Santa Barbara, Ventura, Los Angeles, Orange, San Bernardino and Riverside. This Habitat Conservation Program (HCP) or "programmatic" permit will streamline project permitting process similar to agreements in place for California Desert and San Joaquin Valley.

Physical Description

The Coastal Region Conservation Program will be an Endangered Species Act (ESA), Section 10 agreement between Southern California Gas Company, United States Fish & Wildlife Services (USFWS) and California Department of Fish & Game (CDFG) for a proposed life of 50 years.

Project Justification

- The CRCP provides similar HCP programmatic permitting approach utilized in other parts of SCG territory.
- This HCP will provide an efficient process to assess maintenance and operations activities for threatened and endangered species issues. Without this program, SCG's project scheduling and implementation may be adversely impacted and there is a potential for an increase to overall costs because projects would have to be reviewed by the agency on a case-by-case basis.
- The CRCP develops a comprehensive, long-term program to ensure compliance with complex environmental ESA regulations.
- It requires that SCG conducts up-front biological analysis for the program area utilizing comprehensive database that will provide regulatory certainty to ensure SCG activities can be conducted without environmental impacts that could result in costly delays.

Forecast Methodology

The total cost estimate for developing the CRCP is $2,720,000 (Labor $283k & NL $2,437k) in direct dollars (GWO #77604). Non-Labor cost is primarily consultant expenses for development and

CAPITAL PROJECT WORKPAPER

PROJECT TITLE	BUDGET NO.
Coastal Region Conservation Program – SCG allocation	01100.00
WITNESS	**IN SERVICE DATE**
Ray Stanford	09/30/2011

identification of protocols for sensitive habitat and species impacts. These development costs will be capitalized when the program becomes effective, which is estimated to begin in 3rd quarter 2011. The development amount will be amortized over the 50-year period of the program. This work paper covers the SoCalGas allocated portion, 89.7%. A separate work paper covers the SDG&E portion, 10.3%

Schedule

CRCP application has a planned approval/useful date for Q3 2011. Costs have been captured in **GWO 77604** and will be recorded when CRCP agreement is received.