SCGC DATA REQUEST
SCGC-SCG-DR-03
SOCALGAS 2012 GRC – A.10-12-006
SOCALGAS FINAL RESPONSE
DATE RECEIVED: MAY 31, 2011
DATE RESPONDED: JUNE 16, 2011

3.1. Mr. Phillips presents the projected benefits of the OpEx 20/20 program in Tables SCG-RP-06, SCG-RP-07, and SCG-RP-08 in his testimony.

3.1.1. Are the figures presented in these tables incremental for each year or cumulative?
3.1.2. Please provide a disaggregation of each table to show the savings in dollars on a year-by-year, program-by-program basis showing all of the disaggregated capital benefits in a single table for years 2010-2016 and similarly all of the disaggregated O&M benefits in a single table for years 2010-2016.
3.1.3. Please compare the savings described in the response to the previous question to the savings projected in the OpEx 20/20 O&C Benefits Summary table and the OpEx 20/20 Capital Benefits Summary table that are contained with the spreadsheet,"Soft vs Hard Benefits.Dec 09.xls," provided in response to TURN-SCG-06, Q.4b.
3.1.4. Please explain the differences between the capital and the O&M benefits projected by Mr. Phillips for years 2010-2016 and the capital and the O&M benefits projected in spreadsheet,"Soft vs Hard Benefits.Dec 09.xls, for the years 2010-2016.
3.1.5. For each year and each program, please identify the number of FTEs eliminated by each department, that is, Customer Service, Gas Distribution, Gas Transmission, Gas Operations, Gas Engineering, Gas Storage, Gas Procurement, Construction, IT, and any other (define name.) Figures should not be cumulative to other years but may be annualized if positions are eliminated mid-year.

SoCalGas Response:

3.1.1.

Table SCG –RP-06 represents O&M savings for each year relative to 2009, i.e.2011 savings include 2010 savings.
Table SCG – RP -07 represents capital savings for each year relative to 2009.
Table SCG – RD-08 O&M savings for each year relative to 2012 and capital savings for each year relative to 2009.

3.1.2.

Below are labor and nonlabor O&M and capital savings by project and year for 2010-2015. SoCalGas has limited its response to include years 2010-2015 to match the scope of its proposed post test year ratemaking mechanism (2013-2015).

Response to Question 3.1 (Continued)

O&M

	2010	2011	2012
O&M	Labor and Nonlabor *		
GIS	386	76	(410)
Customer Care	(777)	(2,304)	(5,628)
Supervisor Enablement	(437)	(1,134)	(1,567)
M&I	(343)	(2,110)	(3,330)
Construction	-	-	(400)
Total O&M	(1,171)	(5,473)	(11,335)
	* relative to 2009 savings		

	2013	2014	2015
O&M	Labor and Nonlabor *		
GIS	(612)	(949)	(946)
Customer Care	(1,794)	(1,809)	(1,945)
Supervisor Enablement	(5)	(5)	(5)
Construction	(1,506)	(1,506)	(1,506)
Total O&M	(3,917)	(4,268)	(4,402)
	* relative to 2012 savings		

Capital

	2010	2011	2012	2013	2014	2015
Capital	Labor and Nonlabor *					
GIS	(79)	(123)	(370)	(852)	(1,271)	(1,271)
Supervisor Enablement	(558)	(558)	(558)	(558)	(558)	(558)
M&I	(446)	(1,284)	(1,848)	(1,848)	(1,848)	(1,848)
Construction	-	-	(1,670)	(7,347)	(7,347)	(7,347)
Total Capital	(1,083)	(1,965)	(4,446)	(10,605)	(11,024)	(11,023)
	* relative to 2009					

3.1.3.

Tables SCG – RP-06, SCG – RP-07 and SCG – RP-08 reflect SCG hard savings and are in 2009 direct dollars. O&M savings for 2010-2012 are relative to 2009. O&M savings for 2013-2015 are relative to 2012. Capital savings for each year are relative to 2009.
The file provided as part of the data response to TURN-SCG-06, Q.4b is for both SoCalGas and SDGE savings. The savings are fully loaded, escalated, and for both hard and soft savings.

Response to Question 3.1 (Continued)

3.1.4.

Please see response to 3.1.3

3.1.5.

Below are forecasted FTE equivalent of labor savings by department for 2010-2015. Please note that this is not a one-for-one reduction in employees and "FTE savings". Other factors that influence this are: other upward pressures, use of contractors, other contingent labor, overtime assumptions, etc.

	O&M Hard Benefits		
	2010	2011	2012
	FTEs *		
SCG Distribution	8.2	(13.8)	(34.4)
SCG Customer Service	(13.1)	(40.9)	(87.8)
SCG Engineering	(9.4)	(13.2)	(13.2)
Total O&M FTEs	(14.3)	(67.8)	(135.5)
	* relative to 2009		

	O&M Hard Benefits		
	2013	2014	2015
	FTEs *		
SCG Distribution	(17.9)	(17.9)	(17.9)
SCG Customer Service	(22.5)	(22.7)	(24.4)
SCG Engineering	(5.3)	(9.6)	(9.5)
Total O&M FTEs	(45.7)	(50.1)	(51.8)
	* relative to 2012		

	Capital Hard Benefits					
	2010	2011	2012	2013	2014	2015
	FTEs *					
SCG Distribution	(9.5)	(15.3)	(36.2)	(94.1)	(96.3)	(96.3)
SCG Engineering	(0.4)	(0.6)	(0.9)	(4.8)	(7.9)	(7.9)
Total Capital FTE	(10.0)	(15.9)	(37.1)	(98.9)	(104.2)	(104.2)
	* relative to 2009					

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3.2 Mr. Phillips states in his testimony, Ex. SCG-13, at page RP-11: "The estimated capital savings are shown in the following table. These savings are shown here for illustrative purposes only, as these savings are presented in the testimony of the operational witness in which the forecasted savings occur."

3.2.1 Please identify the labor and non-labor O&M savings that Mr. Phillips is referring to in the testimony or workpapers of Mr. Stanford and Ms. Orcozo-Mieja.

3.2.2 Please identify the capital savings that Mr. Phillips is referring to in the testimony or workpapers of Mr. Stanford and Ms. Orcozo-Mieja.

SoCalGas Response:

3.2.1

The labor and non-labor O&M savings are not in Mr. Stanford or Ms. Orozco-Mejia testimonies. These O&M savings are reflected in Mr. Phillips testimony and workpapers. Please refer to SCG – RP-06, SCG –RP-08 and SCG-13-WP page 18.

3.2.2

Due to the minimal capital savings projected for SoCalGas Gas Engineering (i.e. $34,000 in 2010, $47,000 in 2011, and $69,000 in 2012), Mr. Stanford did not specifically identify the savings in his testimony volume.

For SoCalGas Gas Operations, please refer to table SCG-GOM-26 at page GOM-61 of Ms. Orozco-Mejia's testimony (Exhibit SCG-02).

3.3. In SoCalGas' response to TURN-SCG-06, Question 1, SoCalGas provided copies of various documents that had been provided to its Board of Directors regarding the OpEx 20/20 program. According to a Board presentation document, the GIS is "an Enterprise-wide Geographic Information System that will enable compliance with DOT Gas Transmission and Distribution Pipeline Integrity requirements [for] a detailed registry which includes installation information, condition, and maintenance history of our pipelines." GIS SEU Board at 2. The document further projects that the GIS savings are expected to begin in 2012. Id. at 5. A spreadsheet provided in response to Question 4a, "4a Updated Bus Case.xls," confirms the projection of $7.1 million in savings as of 2012 while a spreadsheet provided in response to Q.4b, "Soft vs Hard Benefits.Dec 09.xls," projects $9.7 million in savings for 2012, of which $4.0 million is expected to be "hard" savings or benefits. The data response defines "hard" benefits as "cost savings that will result in reduction in costs when compared to historical spend."

3.3.1. In light of the aforementioned Board documents, please explain why SoCalGas is requesting to add 4 FTEs in 2012 to 2EN000.000 - Gas Engineering for GIS related activities (at SCG-05-WP Stanford.pdf at 22 and SCG-05-WP Stanford.pdf at 24) instead of seeing a net decrease in staffing levels associated with GIS related activities due to previously projected "hard" and "soft" savings.

3.3.2. In light of the aforementioned Board documents, please explain why SoCalGas is requesting to add 4 FTEs in 2012 to 2200-2325.000 - Pipeline Integrity/ Ops Tech Support – Shared, which is a "new cost center created cost center to track expenses incurred by GIS and database type support that have historically been imbedded in other Ops Tech cost centers" (SCG-05-WP Stanford.pdf at 285) instead of seeing a net decrease in staffing levels associated with GIS related activities due to previously projected "hard" and "soft" savings.

3.3.3. In light of the aforementioned Board documents, please explain why SoCalGas is requesting to add over $4 million in "GIS Enhancements" (SCG-05-WP Stanford.pdf at 58-61) instead of seeing a net decrease in O&M costs associated with GIS related activities due to previously projected "hard" and "soft" savings.

SoCalGas Response:

3.3.1 The development and implementation of the new GIS initiatives requires a higher, greater and different level of technical support. In order to meet the new demands of the increasingly complex suite of systems and the increased number of mobile data terminals throughout the region territories, additional resources are required within the General

Response to Question 3.3 (continued)

Engineering work group. These requirements are detailed in Mr. Stanford's testimony and workpapers. While there are new skills required in Gas Engineering as detailed in Mr. Stanford's testimony, the offsetting O&M hard savings are reflected in Mr. Phillips's testimony tables SCG-RP-06 and RP-07, and workpapers in the "SCG O&M Hard Savings" table.

3.3.2 Within the Gas Engineering organization, a significant number of employees from the Operations Technology/GIS groups supported the Pipeline Integrity (PI) organization, essentially full-time. A new cost center was created to allow for a more direct accounting of these support activities and keep them separated from other non-PI work. In addition, PI's GIS database requirements are evolving and expected to increase further as a result of recent requirements from DOT and other agencies as a result of the San Bruno incident. More data is being requested and processed from PI Assessment and Field Operations activities. This increased volume of data requires additional resources to administer quality control review, interaction with the submitting party to ensure complete and correct data, and processing into the GIS. In summary the collective activities for PI GIS helps assure a robust GIS product. The need for these additional FTEs was not identified at the time of the presentation to the Board of Directors but only became evident after experience with the program.

3.3.3 The initial GIS OpEx 20/20 initiatives were initially developed several years ago. The requirements and project scope at that time were based on current achievable goals and technological solutions. Over time, as work commenced and implementation of the initiatives began, it was evident that improved technology would enable additional enhancements to the products that would provide even greater benefits and efficiencies. However, existing contractual agreements and in-process contractor work streams prohibited many of these enhancements from being integrated with the existing program scope. The additional expense request presented by Mr. Stanford is to address these enhancements. This is similar in nature to Microsoft issuing new versions of Excel or Word while they already have an existing version on the market. System enhancements have been identified that will make the current product more useful and beneficial as noted in Mr. Stanford's testimony.

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3.4 In SoCalGas' response to TURN-SCG-06, Question 1, SoCalGas provided copies of, GIS SEU Board.pdf, that was identified in the previous question, projects at page 3 that some 43% of the benefits from the GIS program would flow to SDG&E yet according to Mr. Stanford's workpapers, SDG&E represents less than 15% of the combined transmission and distribution pipelines.

- 3.4.1 Is the difference between the projected benefits and pipeline share associated with the inclusion of SDG&E's electric system in the GIS project?
- 3.4.2 If the answer to the previous question is "yes," please explain how the cost and benefits of the GIS program break down between the SoCalGas system, the SDG&E gas system and the SDG&E electric system.
- 3.4.3 If the answer to the question immediately preceding the previous question is "no," please explain why there is such a large difference between the projected benefits of the project and the share of the pipeline system.

SoCalGas Response:

3.4.1

Yes

3.4.2.

GIS is a shared asset with all Capital costs recorded at SoCalGas. After the asset is placed in service SoCalGas will bill SDG&E for its share of the asset and the depreciation. The shared asset split (63.8% SoCalGas and 36.2% SDGE) was determined by the number of license users by company. Balanced and Non-balanced O&M costs are recorded at the FERC accounts in which the costs are incurred for, i.e. SoCalGas data conversion costs are recorded at SoCalGas and San Diego Electric data conversion costs are recorded at SDG&E.

Benefits were developed for each Company and department, i.e. Electric Transmission, Electric Distribution, SoCalGas Distribution and San Diego Gas Distribution, based on the departments to where the savings are projected to occur.

3.4.3

N/A

3.5 Mr. Stanford estimates $5 million for the purchase of GHG emissions credits for various SoCalGas facilities. SCG-05-WP Stanford.pdf at 23. Mr. Stanford does not separately project the purchase of emissions credits for SDG&E compression facilities.

3.5.1 Are SDG&E's compressors exempt from the requirement to purchase GHG emissions credits?

3.5.2 If the answer to the previous question is "yes," please explain the exact basis for the exemption of these facilities and state whether SDG&E expects the exemption to persist.

3.5.3 If the answer to the question immediately preceding the previous question is "no," are the emissions from these SDG&E facilities included in the emissions for which Mr. Stanford projects purchasing $5 million in credits during 2012?

3.5.4 If the answer to the previous question is "yes," please describe the method by which SoCalGas proposes to allocate the cost of these emissions credits between SoCalGas and SDG&E as well as the ultimate result of such an allocation.

SoCalGas Response:

3.5.1 SDG&E compressor stations did not meet the minimum threshold of 25,000 metric tonnes (MT) of CO2, and therefore were not included in the estimated purchase cost of emission credits.

3.5.2 SDG&E's two compressor stations have each individually not exceeded the 25,000 MT of CO2 emissions since AB32 was finalized. This is not an exemption per se. Rather it is merely the fact the station's emissions are below the threshold to qualify for inclusion. The operational needs of the company determine fuel consumption and therefore emissions. It is possible the station could qualify in the future as operational needs change.

3.5.3 Not applicable.

3.5.4 If the need for allocations should occur SoCalGas and SDG&E would address the need separately based on facility ownership.

3.6 Mr. Stanford estimates $4.5 million for the payment of fees associated with CARB regulatory activities under AB 32 and another $5.0 million for GHG allowances under cap and trade regulations. SCG-05-WP Stanford.pdf at 23.

3.6.1. Dagg proposes an increased level of non-shared O&M expenses for Gas Transmission in Table SCG-JLD-5 of his testimony, which includes amounts of $229,000 and $179,000 for "CARB-AB 32" and "CARB AB-10x", respectively. Please explain the difference between the activities that Mr. Dagg intends to include in Transmission O&M and those AB 32 costs that Mr. Stanford includes in his O&M budget.

3.6.2 Ms. Orozco-Mejia proposes the adoption of a new environmental balancing account that would cover costs associated with compliance with AB 32. Ex SCG-02 at p. 32-33. Please explain the difference between the activities that Ms. Orozco-Mejia intends to include in Distribution O&M and those AB 32 costs that Mr. Stanford includes in his O&M budget.

3.6.3 Mr. Mansdorfer proposes an increased level of storage O&M expenses to cover compliance with AB 32. Ex SCG-04 at p. JDM-14. Please explain the difference between the activities that Mr. Mansdorfer proposes and those AB 32 costs that Mr. Stanford includes in his O&M budget.

SoCalGas Response:

Please refer to the testimony of Ms. Lisa Gomez (SCG-15), pages LPG-7 thru LPG-11, for a detailed description of the various recently adopted and proposed-for-adoption GHG programs that will impact SoCalGas. Two of the more significant fee-based expense programs, CARB/AB32 administration fee ($4.5 million) and GHG cap-and-trade expenses ($5 million) are presented in Mr. Stanford's testimony and workpapers. Specific details for Mr. Stanford's requests are as follows:

<u>$4.5 million forecast</u> – One of the provisions of AB32 enables the California Air Resources Board (CARB) the ability to adopt a schedule of administrative fees to pay for its program (see SCG-15, page LPG-10). The fee for Local Distribution Company (LDC) natural gas throughput has been proposed by CARB at $0.00084/therm. SCG's 2008 throughput from the 2009 Cal Gas Report (minus allowed exclusions) is approximately 5.41 billion therms. (5.41Btherms x $0.00084/therm ≈ $4.5 million)

Response to Question 3.6 (Continued)

<u>$5.0 million forecast</u> – Please refer to Ms. Gomez' testimony, SCG-15, Page LPG-9) This program addresses the open market emission credit offset purchases (Cap-and-Trade) for major emitters (>25,000 MT/yr) within SoCalGas' service territory. The impacted facilities are Aliso Canyon, Honor Rancho, Blythe, South Needles, and Newberry Springs. The estimated cost of emission credits are $20/MT. The combined emissions for the five facilities in 2008 were approximately 250,000 MT. (250,000 MT x $20/MT = $5.0 million)

These two requests differ from the expense requests of Mr. Dagg, Ms. Orozco-Mejia, and Mr. Mansdorfer as they are mandated fees based on historical data for gas system throughput and emissions levels. Mr. Dagg, Ms. Orozco-Mejia, and Mr. Mansdorfer are requesting funding for operational activities, both new and incremental, to meet new regulations imposed by the passage of the various GHG regulation components.

3.6.1 The expense forecast of $229,000 for CARB AB32 as detailed in Mr. Dagg's workpapers (SCG-03-WP, page 51 thru 53) includes the activities that SoCalGas is implementing to meet the new regulations for GHG emission reductions, and mandatory reporting rules as discussed in the testimony of Ms. Lisa Gomez' (SCG-15, page LPG-7 & 8,). These incremental activities include increases in the frequency of packing seal replacement maintenance; leak survey, monitoring and reporting; repair and maintenance of valves, and flanges; air compressor conversion and air system upgrades; and instrument calibration and repairs.

The expense forecast of $179,000 for AB10X are detailed in Mr. Dagg's workpapers, SCG-03-WP, page 56 thru 63. The State of California's Annual Budget Act authorizes the State EPA to annually assess fees to partially fund CARBs Stationary Source Program. The fees are assessed on facilities emitting 250 tons or more 20 per year of nonattainment pollutants or their precursors of volatile organic compounds within the 21 State.

3.6.2 The "new environmental balancing account" is actually proposed in the testimony of Ms. Lisa Gomez, (SCG-15, page LPG-7, lines 25 through 29). Ms. Orozco-Mejia references this proposal in her testimony to provide the reader additional detail in support of her testimony.
Ms. Orozco-Mejia's forecast for compliance to the new and proposed EPA MRR Subpart W regulations cover the activities included testimony of Ms. Lisa Gomez, SCG-15, pages LPG-7 & 8. This includes activities such as annually reporting of fugitive and vented methane emissions from natural gas distributions systems; conducting annual inventory of gas system components; annually survey for leaks; and conducts other new activities. Compliance may require data collection and increased reporting.

Response to Question 3.6 (Continued)

3.6.3 The forecasted O&M increase due to AB32 compliance as detailed in Mr. Mansdorfer's testimony and workpapers are based on GHG regulations that will take effect in 2012 that will require enhanced fugitive leak detection, monitoring, and repair practices as well as additional reporting and record-keeping requirements. These new regulations will require modifications to existing procedures leading to increases in the frequency of leak detection surveys, enhanced monitoring, and leak repair requirements. These procedural enhancements will generate additional work scheduling and tracking requirements, along with an increased volume of data to be collected, analyzed, reported and stored. Additional work force will be hired to manage the new requirements.

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3.7 In response to TURN-SCG-03, Question 2a-2b, SoCalGas states: "SoCalGas has no record of removal expense for the years 2000-2008 due to physical conflict or perfecting of legal title" and "SoCalGas has no record of removal footage due to physical conflict or perfecting of title for the period of 2000-2008."

3.7.1 Does this mean that SoCalGas has never previously been requested to remove footage of an abandoned line?
3.7.2 If the answer to the previous question is "no," please provide the date(s) prior to 2009 at which SoCalGas has removed an abandoned line at the request of the land owner or a municipality.
3.7.3 Please list all of the lines that SoCalGas considers abandoned, whether the lines are considered distribution or transmission or other, and the county that they are located in.

SoCalGas Response:

3.7.1 No, SoCalGas has historically received requests for the identification and possible removal of sub-surface facilities for both active and formerly abandoned pipelines. When these requests are received, field inspections are conducted to verify the presence of such facilities. When identified, the requestor is consulted and a review of their request is begun to determine final resolution.

Depending on the nature of the request and the land rights under which SoCalGas presence is authorized, the facilities in question are subject to one of several possible resolutions:

- Remain in place, no removal/ relocation needed
- Relocated at requestors expense
- Removed at requestors expense
- Relocated at SoCalGas' expense
- Removed at SoCalGas' expense

Resolutions by the first four methods listed do not result in incremental O&M expenses. It is only those instances under which removal at SoCalGas' expense that additional funding is being sought. These such removals are specially driven by the landowner's desire and right of demand, for the removal of formerly abandoned pipelines and mitigation of any associated disposal management expenses they would otherwise incur were they to negotiate with SoCalGas for the formerly abandoned pipeline to remain in-place, and acquire release of SoCalGas' right of presence through the filing of a quit-claim by SoCalGas.

Response to Question 3.7 (Continued)

3.7.2 SoCalGas has no record of removal of formerly abandoned pipelines for the years 2000-2008.

3.7.3 SoCalGas does not have a listing of all formerly abandoned pipelines readily available, and will therefore need to provide it under a supplemental response to this data-request.

3.8 In the Mr. Stanford's testimony at page RKS-76, he states "The biggest is for relocation of Lines 1016 and 4000 due to six railroad grade separation projects in Orange County. This project alone will cost approximately $13.6 million over years 2011 and 2012 and is not collectible." However, in Mr. Stanford's capital workpapers at page RKS-CWP-215 there is a "collectible" amount of $2,716,000 shown for 2012.

3.8.1 Is Mr. Stanford's statement in his testimony correct?
3.8.2 If the answer to the previous question is "yes," what does the $2.7 million collectible shown in his workpapers correspond to?
3.8.3 Please break down the $4.5 million and $9.0 million of construction costs shown for 2011 and 2012, respectively, by each grade separation project listed under the Business Purposes heading.
3.8.4 In previous years, have OCTA's construction projects run consistently with the preliminary schedules that have been provided to SoCalGas or have they been subject to delay?
3.8.5 If the OCTA projects have been subject to delay, how much delay has SoCalGas experienced relative to the estimated timeline in the preliminary estimates?
3.8.6 Is OCTA's ability to proceed with the grade separation projects dependent upon the passage of Measure M?
3.8.7 Has Orange County already passed the Measure M that is referred to in Mr. Stanford's workpaper at page RKS-CWP-215?
3.8.8 If the answer to the previous question is "no," please state when Measure M would be on the ballot.
3.8.9 Is OCTA's ability to proceed with the grade separation projects dependent upon the approval of federal funding?
3.8.10 Has OCTA gotten final approval for its federal funding?
3.8.11 If the answer to the previous question is "no," what is required for OCTA to obtain federal funding and is OCTA assured of that funding if it meets all of the requirements?

SoCalGas Response:

3.8.1 No, the statement in Mr. Stanford's testimony reflects an earlier version of this project. The information in the corresponding capital workpaper is correct and therefore the statement on RKS-76 should read, "This project alone will cost approximately $13.6 million over years 2011 and 2012 and will be approximately 30% collectible."

3.8.2 Not applicable

Response to Question 3.8 (Continued)

3.8.3 Costs for five of the six sites were estimated at approximately $2.0 million each, based on the experience of the project manager with pipeline relocations of similar Line sizes and project scope. Each of these five sites involved a single pipeline. The Orangethorpe Ave. site was estimated at approximately $3.5 million because two pipelines exist at that site. Two relocations would have cost approximately $4.0 million but was discounted $500,000 due to economies of the contractor working on two lines at the same site.

3.8.4 Placentia Avenue was originally planned for construction in 2001. Orangethorpe Avenue was originally planned for construction in 2002 but is expected to be on schedule for 2012. SoCalGas was made aware of the other projects in 2009. At this time, most seem delayed between 6 months to a year from the original projections. OCTA has stated in meetings with involved parties that their principal motivation is to begin construction by close of 2013 to qualify for federal funds.

3.8.5 Please see our response to Question 3.8.4.

3.8.6 SoCalGas' understanding is that partial funding comes from Measure M but we may not have knowledge of the source of governmental project funding. SoCalGas, as a public utility, relocates its pipelines found to be in conflict with federal, state, or local improvement projects in respond to a formal "Notice to Relocate" issued by the governmental franchise grantor.

3.8.7 SoCalGas believes Measure M passed in 2004 or 2005 but please refer to our response to Question 3.8.6 above with respect to our knowledge of the source(s) of improvement funding.

3.8.8 Not applicable. Please see response to Question 3.8.7.

3.8.9 SoCalGas believes that federal funding is contributing to these projects but please refer to our response to question 3.8.6. with respect to our knowledge of the source(s) of public improvement funding.

3.8.10 Please refer to the response to Question 3.8.9.

3.8.11 SoCalGas has been given no reason to doubt that these projects are fully funded but please refer to our response to Question 3.8.6., relative to our franchise requirement to relocate when ordered.

3.9 How does SoCalGas estimate its yearend CAC balances for 2010, 2011, and 2012 relative to its recorded yearend 2009 CAC balance?

3.9.1 Are the monthly and yearend figures for 2009 based on recorded data?

3.9.2 Please explain in detail how any escalation factor(s) have been developed.

3.9.3 Please explain why SoCalGas believes that its factors provide an accurate prediction of future CAC balances.

SoCalGas Response:

As stated in the prepared direct testimony of Garry Yee, Exhibit SCG-26, Page GGY-9:

> "The estimated years 2010 and 2011 and TY2012 balances are forecasted based on a historical five-year trend of CAC balances from 2005 to 2009 for distribution new business and forecasted activity for transmission new business. The use of five years of historical data for distribution is consistent with and in line with currently adopted methodology used by capital and O&M witnesses in their forecasts, as well as with prior SoCalGas rate case proceedings before this Commission. The CAC balances include the receipts of cash advances, which are recorded as increases, and refunds and/or forfeitures of cash advances, which are recorded as decreases. Please see supporting work papers for the detailed computation."

SoCalGas used a 5-year average of the monthly change in distribution CAC balances as a basis to estimate monthly CAC balances from 2010 through 2012. The calculated 5-year average was applied each month to the prior months ending balance to develop the forecast.

For Transmission projects, SoCalGas developed the CAC forecast by analyzing each transmission new business project and using the contract dates as the basis for estimating the timing of activities.

3.9.1 – Yes, the 2009 numbers presented are recorded data.

3.9.2 – Escalation factors were not used in the development of the forecast.

3.9.3 – No escalation factors were used. See above responses.

3.10. In Mr. Stanford's capital workpapers at page RKS-CWP-226, he discusses the proposed $3.3 million overhaul of the Newberry compressor and states that doing so will reduce O&M costs as follows:

- 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.

3.10.1 Did SoCalGas experience an amplified level of maintenance requirements for the Newberry compressor during 2009?

3.10.2 Has SoCalGas reduced its projected transmission O&M expense for 2012 to reflect the expected $50,000 in fuel savings, $25,000 in O&M reduction, and at least a portion of the $50,000 projected savings in major mechanical repairs that are expected to accompany the proposed overhaul of the Newberry compressor?

3.10.3 If the answer to the previous question is "yes," please demonstrate in specific terms to what accounts or budget areas these adjustments were made.

3.10.4 If the answer to the question preceding the previous question is "no," please explain why SoCalGas is not reducing its O&M costs while claiming those benefits will accompany its proposed compressor overhaul project.

SoCalGas Response:

Note: The Capital workpaper referenced in this data request (RKS-CWP-224 thru 226) is for a project to upgrade the control systems at SoCalGas' Newberry Compressor Station and not for a compressor overhaul as mentioned in the question above.

3.10.1 SoCalGas' experience has been that maintenance costs trend upward as control systems become older and less reliable. Data over the last few years at Newberry Station indicate that both labor costs per operating hour and the number of maintenance call-outs per operating hour have trended upward, both indicative of aging equipment and increasing maintenance costs.

3.10.2 The three estimated expense savings referenced in the question above have not been excluded from transmission's O&M based on the following: 1) Fuel costs are excluded from the General Rate Case and addressed in a separate proceeding. 2) As presented in the Project Justification section of the capital workpaper, page RKS-CWP-225, "Offsets to costs are principally avoided: future O&M, fragmented capital replacement cost, and customer impacts." In line with that

Response to Question 3.10 (Continued)

statement, the estimated $50,000 savings in "major mechanical repairs" would be categorized as avoided capital expenditures that would be required if the control upgrades are not completed. Likewise, as the existing controls continue to age, this project will avoid an estimated $25,000 of additional future O&M costs due to increased maintenance, diagnostic, repair, and parts acquisition activities.

3.10.3 Not applicable.

3.10.4 Not applicable. Please see our response to Question 3.10.2.

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3.11 In Mr. Stanford's capital workpapers at page RKS-CWP-234, he discusses the proposed $1.1 million replacement of an electric generator at the Newberry compressor station with three natural gas-fired micro-turbines.

3.11.1 Do the emissions from these micro-turbines contribute to SoCalGas' projected emissions at Newberry that are included in the as part of the justification for SoCalGas' projected $5 million in allowance costs? (See page 23 of Mr. Stanford's workpapers.)

3.11.2 If the answer to the previous question is "yes," did SoCalGas consider replacing the electric generator with a new electric generator?

3.11.12 Why did SoCalGas decide to use micro-turbines?

SoCalGas Response:

3.11.1 The emissions from the proposed micro-turbines are not included in the emissions allowance cost calculations presented on pages RKS 22 and 23. As detailed in Mr. Stanford's testimony beginning on Line 11 of Page RKS-22, the GHG emissions allowance costs are based on 2008 historical emissions values and do not include theoretical emissions for proposed equipment.

3.11.2 N/A

3.11.3 SoCalGas has chosen to replace one of the aging Waukesha 350 kW electric generators at Newberry Springs compressor station with three Capstone micro-turbine generators for a number of reasons. Paramount in the decision was increased reliability, lower installation and operating costs, and lower emissions. These observations are based on equipment specifications as well as SoCalGas' experience with its existing micro-turbine installations.

Additional reasons why the micro-turbine option was selected include: Micro-turbines do not require exhaust after-treatment (catalysts), emission compliance monitoring, catalyst replacement and emission testing, and as such are easier to permit. They produce fewer emissions than traditional engine driven equipment. Their installation would eliminate the need for needed electric power distribution upgrades (for existing equipment) and require less auxiliary systems (cooling and power) than traditional engine driven equipment. Additionally, the installation of new engine driven units included a new building to house generator units, where micro turbines can be installed outside. These benefits along with SoCalGas' experience with micro-turbine technology and reliability have driven the decision for this project.

3.12 Mr. Stanford's workpapers at RKS-WP-36 estimates that SoCalGas will inspect and verify 73 assessment or reassessment projects through 2012.

3.12.1 Is SoCalGas required to complete these 73 projects by the end of 2012?
3.12.2 What are the consequences of failing to complete these projects by the end of 2012?
3.12.3 Did SoCalGas estimate the cost of the 73 projects on a project specific basis or did SoCalGas estimate the cost on a mileage or other unit basis.
3.12.4 If costs were estimated on a mileage or other unit basis, what is the unit cost used and how did SoCalGas develop the unit cost?
3.12.5 What fraction of the 73 projects has been completed to date?
3.12.6 What is the recorded cost of those projects that have been completed to date?

SoCalGas Response:

3.12.1 Yes. Based on the federal regulations prescribed in 49CFR 192.921(d) *Time Period* – "… An operator must complete the baseline assessment of all covered segments by December 17, 2012." The 73 projects referenced above are part of SoCalGas' transmission integrity management program for which a baseline assessment has yet to be performed.

3.12.2 DOT has not defined the consequences for failing to comply with the federal regulations prescribed in 49CFR Part 192, SubPart O – Gas Transmission Pipeline Integrity Management. SoCalGas' Transmission Integrity Management Program was designed to complete the baseline assessments of all required covered segments in order to remain in compliance with federal regulations.

3.12.3 The following is an excerpt found in the capital workpapers for inline inspection (example: RKS-CWP-94) explaining the methodology for calculating the various costs, including O&M, associated with this assessment methodology.
"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.

Response to Question 3.12 (Continued)

3.12.4 See the response to Question 3.12.3.

3.12.5 Seventeen projects, or 23% of the 73, have been completed to date.

3.12.6 Of the 17 completed projects, approximately $6.9 million has been spent.

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3.13 Mr. Stanford's workpapers at RKS-WP-36 estimates that SoCalGas will complete "External Corrosion Direct Assessment of Department of Transportation defined Transmission Pipeline per Baseline Assessment Plan is 51.46 miles in 2010, 15.20 miles in 2011, and 16.11 miles in 2012 @ $32,000/mile to survey (with a minimum cost of $15,600 per project and 1.79 digs/mile (with a minimum of 4 digs per project) at a cost of $40,000 per dig for non-labor. 152 digs are forecasted for 2010, 59 in 2011, and 155 in 2012."

3.13.1 How did SoCalGas determine its assessment mileage estimate for 2010, 2011, and 2012?
3.13.2 What has SoCalGas' actual completed assessment mileage been for 2010 and 2011 to date?
3.13.3 What is the recorded cost of the actual completed assessment mileage to date?
3.13.4 Are there any consequences if SoCalGas were to fail to meet its projected mileage goals for any of these years?
3.13.5 If the answer to the previous question is "yes," please specify the consequences.
3.13.6 How did SoCalGas determine its unit cost (per mile) assessment?
3.13.7 Please provide a copy of any study that SoCalGas has performed of baseline assessment costs for transmission pipelines.

SoCalGas Response:

3.13.1 The assessment mileages for 2010, 2011, & 2012 ECDA projects were taken directly from the Baseline Assessment Plan and were not estimated.

3.13.2 Completed ECDA mileage is as follows:

ECDA Actual	2010	2011
Mileage completed	18.22	1.00
Mileage in progress	2.69	17.83
Miles moved from ECDA to alternate program method	31.72	5.65

Response to Question 3.13 (Continued)

3.13.3 Recorded costs for completed assessments are as follows:

ECDA	2010 ($000)	2011 ($000)
Recorded costs	$4,750	$1,200

3.13.4 DOT has not defined the consequences for failing to comply with the federal regulations prescribed in 49CFR Part 192, SubPart O – Gas Transmission Pipeline Integrity Management. SoCalGas' Transmission Integrity Management Program was designed to complete the baseline assessments of all required covered segments in order to remain in compliance with federal regulations.

3.13.5 Not applicable

3.13.6 The cost to perform indirect inspection surveys was determined using the average survey cost per mile for 2008-2010 projects that had been completed. The estimated cost used was $32,000 per mile which has been consistently used for internal planning. The actual average survey cost per mile was $35,420 per mile. The cost per dig was determined using the average cost per direct examination bell hole ("dig") for completed 2008-2009 projects which was $40,000. The actual average direct examination cost was $39,885.

ECDA Projects from 2008 – 2009

ECDA Project	Miles Surveyed	No. Digs	Total Survey Costs	Survey Cost per mile	Total Direct Exam cost	DE Cost/Dig
L 32-24 &44-725	1.26	4	$ 42,581	$ 33,754	$ 289,791	$ 72,448
Line 41-05	13.85	18	$ 338,069	$ 24,415	$ 523,084	$ 29,060
Line 32-60	5.94	8	$ 154,014	$ 25,927	$ 306,000	$ 38,250
Line 36-1007	2.73	4	$ 50,523	$ 18,540	$ 96,167	$ 24,042
Line 36-6593	0.99	4	$ 52,987	$ 53,785	$ 157,687	$ 39,422
Line 32-25	1.18	4	$ 35,729	$ 30,364	$ 62,471	$ 15,618
Line 35-10	3.47	4	$ 105,769	$ 30,505	$ 233,503	$ 58,376
Line 36-9-09S	1.23	5	$ 37,065	$ 30,201	$ 121,740	$ 24,348
Line 36-9-09N	7.08	11	$ 336,524	$ 47,500	$ 567,832	$ 51,621
Line 36-9-21	11.04	6	$ 144,449	$ 13,083	$ 322,931	$ 53,822
L 43/45-1106	1.03	8	$ 64,319	$ 62,393	$ 284,765	$ 35,596
Line 44-1008	1.12	4	$ 40,317	$ 35,971	$ 166,500	$ 41,625
Line 38-501	1.36	10	$ 73,444	$ 54,027	$ 342,821	$ 34,282
			Average>>	**$ 35,420**	**Average>>**	**$ 39,885**
			Used>>	**$ 32,000**	**Used**	**$ 40,000**

Response to Question 3.13 (Continued)

Estimating Survey Costs
For planning, $32,000 per mile for survey costs was used. However, short mileage projects have a fixed cost no matter the length because it takes a set amount of time for the survey crews to mobilize and demobilize on each project. So regardless of length, each and every project requires a minimum of three days of crew time. Crew time costs $5,200 per day.

For projects less than one mile in length, the following was used:

- 0.01 - 0.50 miles requires a minimum of 3 days for the survey crew. The cost is $5,200 per day = a minimum of $15,600 for the three days
- 0.50 - 1.00 miles requires a minimum of 5 days for survey crew. The cost is $5,200 per day = a minimum of $26,000 for the 5 days
- 1.00+ miles uses the $32,000 per mile for the surveys

The greater of "mileage based cost" or "project minimum" was used.

Example:

Project	Total HCA Miles	Cost/Mile	Mileage-based Cost	Project Minimum	Estimated Survey Cost
Project 408-RA	0.14	$ 32,000	$ 4,480	$ 15,600	$ 15,600
Project 41-17A	0.71	$ 32,000	$ 22,720	$ 26,000	$ 26,000
Project 38-504	10.32	$ 32,000	$330,240	--------	$ 330,240

Estimating Direct Examination Costs
There have been 67 completed projects for a total of 279 HCA miles. Associated with these projects, 500 direct examination digs were conducted. This equates to an average of 1.79 digs per HCA mile. This factor was applied to the number of HCA miles planned per project per year from the March 2010 baseline assessment plan per project.

Additionally, 49 CFR 192, Subpart O, references the NACE SP0502 standard for ECDA which requires a minimum of 4 digs per project so the total number of "Project Minimum Digs" was entered as 4. If the project's HCA mileage is low, the project minimum digs must be used.

The "Estimated Minimum Digs" is the greater of "Mileage-based digs" or "Project Minimum digs". Note that actual field data results could require more than the "Estimated Minimum Digs."

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Example

Project	Total HCA Miles	Digs/Mile	Mileage-based Digs	Project Minimum Digs	Estimated Minimum Digs
Project 1023	0.86	1.79	1.54	4	4.00
Project 41-17	2.84	1.79	5.08	4	5.08
Project 38-504	10.32	1.79	18.47	4	18.47

This calculation was performed for each project by year to forecast the "Estimated Minimum Digs".

GRC Survey and Dig Estimates – Summary

Using the methodologies outlined above and the cost averages from ECDA projects performed and completed from late year 2008 through early 2010, the cost estimates listed below were generated. Because of project minimums for surveys and minimum dig requirements discussed above, the survey costs listed below are not a simple multiplication of HCA miles times $32,000/mile and the dig costs listed below are not a simple multiplication of digs times $40,000 per dig. As described in the sections above, the costs were estimated for each project using the methods described and the table below is a summary of those individual estimates.

	2010			
Category	**Miles of HCA**	**Survey Cost**	**Digs**	**Dig Cost**
SoCal Distribution HCA	39.82	$1,321,680	107.92	$ 4,316,732
SoCal Transmission HCA	11.64	$ 400,320	44.00	$ 1,760,000
Total		$1,722,000		$ 6,076,732

	2011			
Category	**Miles of HCA**	**Survey Cost**	**Digs**	**Dig Cost**
SoCal Distribution HCA	11.43	$ 404,640	38.47	$ 1,538,860
SoCal Transmission HCA	3.77	$ 144,800	20.00	$ 800,000
Total		$ 549,440		$ 2,338,860

	2012			
Category	**Miles of HCA**	**Survey Cost**	**Digs**	**Dig Cost**
SoCal Distribution HCA	11.94	$ 625,200	110.93	$ 4,437,092
SoCal Transmission HCA	4.17	$ 225,680	44.00	$ 1,760,000
Total		$ 850,880		$ 6,197,092

Response to Question 3.13 (Continued)

3.13.7 Aside from the development of unit cost, provided in question 3.13.6 above, no special study of baseline assessment costs has been performed. SoCalGas performs project, cost center, & departmental cost tracking to compare plan versus actual on a regular basis.

3.14. Mr. Stanford's workpapers at RKS-WP-36 estimates that SoCalGas will rely upon "3rd party vendor to prepare detailed feature studies of 35 pipelines prior to integrity assessment. 20 of these projects are characterized as short lines at a flat rate of $16,000/line, and the 15 remaining projects are longer lines totaling 894.7 miles, at a cost of $3400/mile. 10% charge or $336,198 for scanning and indexing the work product.

3.14.1 What would be the consequence (if any) of SoCalGas failing to complete all 35 pipelines by the end of 2012?
3.14.2 Has SoCalGas based these estimates on bids with multiple parties submitting the estimates for the work?
3.14.3 If the answer to the previous question is "no," please provide a detailed and complete explanation of the basis for SoCalGas' project cost and mileage estimates.
3.14.4 What was the variation in costs on $/mile basis among the various estimates submitted?
3.14.5 Please provide a copy of each estimate submitted to SoCalGas by the third party vendors proposing to complete this work.
3.14.6 Please provide a copy of any email, memo, spreadsheet, or other document comparing and/or evaluating the various estimates for the pipeline feature studies.
3.14.7 Which pipeline feature studies have been completed to date?
3.14.8 What is the recorded cost of those completed pipeline feature studies?

SoCalGas Response:

3.14.1 DOT has not defined the consequences for failing to comply with the federal regulations prescribed in 49CFR Part 192, SubPart O – Gas Transmission Pipeline Integrity Management. SoCalGas' Transmission Integrity Management Program was designed to complete the baseline assessments of all required covered segments in order to remain in compliance with federal regulations.

3.14.2 No, the estimates are based on prior work that SoCalGas' current Feature Study contractor, EDM, has performing for SoCalGas.

Response to Question 3.14 (Continued)

3.14.3 The spreadsheet below provides the data by which the estimated feature study forecast was created. For the Large projects, over 5 miles in length, The average cost per mile was used. For the small projects, less than 5 miles, the average cost per project was used.

Vendor	Average Cost 2008-2010	Job Size	Units
EDM	$3,393	Large	Cost per mile
EDM	$16,038	Small	Cost per project

Vendor	Line Number	Total Cost	Miles	Cost/ Mile	Year	Size
EDM	L-1192	$62,879	11.39	$5,521	2008	Long
EDM	L-1185	$25,287	15.50	$1,631	2008	Long
EDM	L-1014	$139,572	24.70	$5,651	2008	Long
EDM	L-765	$299,524	31.50	$9,509	2008	Long
EDM	L-8109	$129,736	57.50	$2,256	2008	Long
EDM	L-335	$72,640	64.90	$1,119	2008	Long
EDM	L-235 N-N	$106,472	115.20	$924	2008	Long
EDM	L-235 N-Q	$171,911	117.00	$1,469	2008	Long
EDM	L408	$8,017.85	0.2	$45,767	2009	Short
EDM	12	$14,833	0.21	$69,740	2009	Short
EDM	L1025	$10,454.08	0.3	$33,352	2009	Short
EDM	L1167	$13,828.05	0.1	$98,665	2010	Short
EDM	L-257	$11,370.94	0.2	$50,453	2010	Short
EDM	L80	$19,038.55	0.7	$28,150	2010	Short
EDM	L160	$17,960.45	0.8	$23,398	2010	Short
EDM	L1021	$24,709.75	1.0	$25,373	2010	Short
EDM	L-1031	$24,126.17	1.0	$23,833	2010	Short
EDM	L2010	$17,951.99	7.4	$2,424	2010	Long
EDM	L4002 & 1185	$49,876.54	14.3	$3,484	2010	Long
EDM	L85South	$92,675.70	27.8	$3,332	2010	Long

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3.14.4 Not Applicable.

3.14.5 Attached is the Rate Sheet from SoCalGas' Feature Study contractor, EDM.

EDM Rate Sheet.pdf

3.14.6 Not Applicable. EDM was used as a sole source.

3.14.7 There have been 9 "short line" and 11 "long line" feature study projects completed to date. The remainder are still in progress or are pending commencement.

3.14.8 The recorded costs for the completed feature studies from the response to question 3.14.7 are approximately $805,000. ($481,000 in 2010, and $324,000 in 2011.)

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3.15 Mr. Stanford's workpapers at RKS-WP-37 estimates that SoCalGas "will conduct tethered In-Line Magnetic Flux-Leakage (MFL) inspection of cased transmission pipeline to comply with the PHMSA baseline assessment and future re-assessment requirements. These segments of cased pipeline cannot be inspected using the appropriate assessment method, External Corrosion Direct Assessment, because it is ineffective on pipelines that are shielded and cannot be physically accessed to perform direct assessment validations. 3 cased pipeline segments assessed in 2010, 43 in 2011, and 74 in 2012 at $103,600 per project for the MFL tool cost, inspection analysis, and program documentation."

3.15.1 What would be the consequence (if any) of SoCalGas failing to complete all the proposed MFL inspections by the end of 2012?
3.15.2 Has SoCalGas based its estimate of $103,600 per project on estimates made by multiple parties?
3.15.3 If the answer to the previous question is "no," please provide a detailed and complete explanation of the basis for SoCalGas' project cost estimate.
3.15.4 What was the variation in costs on $/project basis among the various estimates submitted?
3.15.5 Please provide a copy of each estimate submitted to SoCalGas by the third party vendors proposing to complete this work.
3.15.6 Please provide a copy of any email, memo, spreadsheet, or other document comparing and/or evaluating the various estimates for the MFL inspections.
3.15.7 Which MFL inspections have been completed to date?
3.15.8 What is the recorded cost of those completed MFL inspections?

SoCalGas Response:

3.15.1 DOT has not defined the consequences for failing to comply with the federal regulations prescribed in 49CFR Part 192, SubPart O – Gas Transmission Pipeline Integrity Management. SoCalGas does not entertain the idea of noncompliance as an option. Further its Transmission Integrity Management Program is designed to complete the baseline assessments of all required covered segments in order to remain in compliance with federal regulations.

3.15.2 No.

3.15.3 The costs were based on a single vendor's (Baker Hughes) estimate for the inspection activities and internal knowledge for pipe excavation work. Baker Hughes (V-Line) was the only vender who had a tool and process that could meet SoCalGas' set of tether inspection assumptions for a single sided entry and launch configuration. Attached is an email with their quote for a specific project size. This quote was scaled to the amount of $103,600 to serve as a better estimated "average" value for the variation in job sizes included in this request.

Response to Question 3.15 (Continued)

Also included below is a detailed description of their "V-Line" inspection procedures.

FW V-Line Tool Questions.msg

V-Line Inspection Guidelines.pdf

3.15.4 Not applicable

3.15.5 Not applicable

3.15.6 Please see the response to 3.15.3

3.15.7 Two tethered-ILI MFL assessments were completed in 2010 and four have been completed so far in 2011.

3.15.8 For 2010, the recorded costs were approximately $235,000. In 2011, the costs to-date is approximately $722,000.

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3.16 Please provide a complete working electronic copy of the Excel cost allocation and rate design spreadsheet model as well as any other Excel spreadsheet that was relied upon by Mr. Lenart in preparing his testimony and rate tables. (Ex 40 G Lenart) Working Excel spreadsheets contain all links to other Excel spreadsheets in active format.

SoCalGas Response:

Please see the files provided with the accompanying CD, titled "2011 SCG RD Model 1-18-11.xls" and "2011 SDGE RD Model 1-18-11.xls." Note these models were updated since the December 2010 GRC Application and accompanying testimony to reflect the January 2011 update of the Results of Operations testimony, with rates in effect beginning January 1, 2011.