SAN DIEGO GAS AND ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
2013 TRIENNIAL COST ALLOCATION PROCEEDING (A.11-11-002)
(7th DATA REQUEST FROM SCGC)

QUESTION 7.1:

7.1. Please provide an unredacted copy of the SoCalGas/SDG&E's response to DRA-OCE-1 Redacted in Word format.

RESPONSE 7.1:

Response separately provided pursuant to Non-Disclosure Agreement between SoCalGas and SDG&E and SCGC dated November 8, 2012.

QUESTION 7.2:

7.2. Regarding SoCalGas/SDG&E's response to DRA-OCE-1-4, which states:

> The drilling projects require numerous vendors/contractors to supply all of the services and the materials needed to complete the work. Given the highly variable process of drilling wells (many scope changes during the process), all of the services for the drilling work were provided via a time and materials contract basis where pricing was negotiated either via an existing vendor/SoCalGas MSA (Master Service Agreements) or via one time request for proposal/or pricing and availability request. Many of the smaller ancillary services were awarded the work based on the SoCalGas existing/pre-negotiated MSA and pricing agreements with the vendors.
>
> The major, one time services such as the drilling rig(and drilling rig personnel), directional services, cementing services were selected and hired by SoCalGas utilizing a request for pricing/availability method and a price comparison/quality of service/equipment evaluation.

7.2.1. Was the second drilling contractor identified as part of SoCalGas' search described above?

7.2.2. If the answer to the previous question is "yes," please explain why the first contractor was selected rather than the second contractor.

7.2.3. Please provide a copy of the notes, reports, memos, emails, minutes or any other written documentation of the selection process that was employed to select each of the two drilling contractors that SoCalGas employed to complete the wells at Honor Rancho.

7.2.4. Please provide the names of the two drilling contractors, indicating which contractor was hired first.

7.2.5. Provide a summary of the terms of payment for each contractor.

7.2.6. Did SoCalGas require each contractor to post a performance bond as part of the contractual arrangements?

7.2.7. If the answer to the previous question is "no," please explain in detail why SoCalGas believes that it was appropriate to complete the drilling work without any performance bond.

7.2.8. Does SoCalGas routinely require the posting of performance bonds by its construction contractors?

7.2.9. Please explain SoCalGas' reasoning behind its policy regarding performance bonds.

RESPONSE 7.2

7.2.1: Yes

7.2.2: The first directional drilling contractor, Sperry Drilling Services/Halliburton was selected based on the best price as well as directional drilling personnel commitment.

7.2.3: See attached bid summary evaluation sheet, which contains Protected Materials pursuant to the Non-Disclosure Agreement between SoCalGas and SDG&E and SCGC dated November 8, 2012.


Acrobat Document.pdf

7.2.4: The two directional drilling contractors used during the project were Sperry Drilling Services/Halliburton, and Baker Hughes-INTEQ. Sperry was used first and Baker Hughes-INTEQ was used second.

7.2.5: See the response to DRA-OCE-1; Question 1-3

7.2.6: No

7.2.7: Drilling work is not performed in the same manner as a typical construction project and as such, performance bonds are not commonly used during well drilling projects. However, Limited Liability Lost In Hole (LIH) insurance is offered by the directional drilling vendor to offset the replacement costs of directional drilling tool(s) should they happen to become stuck in the well due to unforeseen geologic cirucumstances. SoCalGas insured all the directional drilling tools during the duration of the drilling project, including those lost in the well.

7.2.8: See Response 7.2.7. SoCalGas does not routinely require posting of performance bonds for drilling operations.

7.2.9: See Response 7.2.8

QUESTION 7.3:

7.3. Regarding page 7 of the Updated Mumford/Van de Putte Direct Testimony, which states:

> The changes to the processing plant discussed above were made over a very short duration between the time the CPCN was approved and the start of the withdrawal season in November 2010. Due to the compressed time frame and time of year, only half of the plant was taken out of service at a given time to allow for the required plant modifications while maintaining continued withdrawal capacity. The required construction schedule led to higher Company and contract labor costs than originally estimated.

7.3.1. Did the original cost estimate assume that the entire storage field would be taken out of service in order to complete the expansion project?

7.3.2. How many months duration (from the approval of the CPCN to the completion of the work) would have been required to enable the removal of the Honor Rancho field from service so that the work could be completed on a full field basis rather than a half of a field basis?

7.3.3. Please identify the incremental cost increase (in dollars) associated with completing the construction work on a half field rather than a full field basis.

RESPONSE 7.3:

7.3.1 The original estimate did not assume that the entire field would be taken out of service, but did assume that the entire dehydration and oil stabilization plant would have been taken out of service to isolate equipment as needed to make plant modifications.

7.3.2 The plant (not field) shutdown and construction was delayed by four months from April to August 2010.

7.3.3 A detailed cost analysis associated with the delays has not been performed.

QUESTION 7.4:

7.4. Regarding page 8 of the Updated Mumford/Van de Putte Direct Testimony, which states:

> In order to provide electrical power to the new down hole pumps that are installed in the new production wells, the existing electrical service from Southern California Edison Company (SCE) had to be expanded and a new electrical system from the plant to the well sites had to be installed….This cost was inadvertently not included in the estimate for plant modifications provided in the Application, but the equipment is needed to provide power for the new down hole pumps installed in the new production wells.

7.4.1. When was the omission of the electrical service component of the project realized?

7.4.2. Did the completion of the previously unknown electric service changes extend the project schedule in any way?

7.4.3. If the answer to the previous question is "yes," please state how many days the schedule was extended as a result of the electrical service.

RESPONSE 7.4:

7.4.1 As stated, the cost was inadvertently not included in the estimates provided in the Application. The work was planned and implemented as needed. The omission of the cost estimate in the Application was identified in May 2011 when re-evaluating the actual cost of the project.

7.4.2 No, the cost estimate was not included in the CPCN Application.

7.4.3 N/A

QUESTION 5:

7.5. Regarding page 13 of the Updated Mumford/Van de Putte Direct Testimony, which states:

> The production hole section was successfully drilled to the geologic target location and target measured depth of 11,300 feet; however, during the subsequent required drilling operations prior to running the production casing the lower 500 feet of the 124" hole section became unstable and caused major operational and production casing installation problems. The wellbore stability problem was unforeseen and was a much different problem than was experienced drilling the first liquid production well WEZU C2C.

7.5.1. Please provide a detailed explanation of the differences between the drilling problems experienced by the first contractor in drilling well WEZU C2C and the drilling problems experienced by the second contractor in drilling well WEZU C7.

7.5.2. Were the problems encountered by the first contractor in drilling WEZU C2C foreseeable or caused by the performance of the first contractor?

7.5.3. If the answer to the previous question is "yes," please explain.

RESPONSE 5:

7.5.1: The drilling difficulties experienced during the drilling of WEZU C2C were primarily related to the ability of the directional drilling tools to steer the bit along the planned directional well path in the lower section of the wellbore. The encountered geologic formations in the well made it difficult for the directional drilling tools to maintain the planned course and the stresses placed on the directional tools while attempting to steer and maintain the well course caused the drilling tool mechanical failures. In the case of WEZU C7, there were no difficulties in maintaining the planned directional well course with the directional drilling tools. However, in the WEZU C7 well, the lower section of the wellbore and the geologic formation in that section of the wellbore became mechanically unstable over time, thus causing wellbore sloughing and the hole began to cave in. In this instance, bottomhole assemblies became stuck in the wellbore during the wellbore cleanout operations because of the wellbore sloughing, and the drilling tools were lost in the wellbore.

7.5.2: No, the difficult geologic formation properties and the drilling conditions in WEZU C2C were not anticipated and were not foreseeable.

7.5.3: N/A

QUESTION 7.6:

7.6. Regarding Tables 1 and 2 that are presented on page 5 of the Updated Mumford/Van de Putte Direct Testimony:

7.6.1. Company labor increases from $345,347 to $1,177,455. Please describe the activities that the company's employees were involve in that account for such an increase in cost.

7.6.2. Labor indirects increase from $760,465 to $2,784,892. Please provide the basis for the cost increase including calculation that tie the increase in indirects back to the increase in labor direct expenses.

7.6.3. AFUDC increases from $456,181 to $2,113,883. Please provide the calculation of AFUDC for each of the two dollar amounts in Excel workbook format complete with working formulas.

7.6.4. Please state the total number of days that the project was delayed considering all factors described in the testimony.

7.6.5. Please provide a breakdown of the number of days delay provided in the response to the previous question by the factor that caused the delay.

RESPONSE 7.6:

7.6.1 Company employees were involved in the CPCN Filing, Project Management, Engineering, Procurement, Field and Plant Shutdowns and Construction activities. Labor charges for the project started in 2008 and continued through 2012.

7.6.2 Labor indirects are tied directly to direct labor costs. Any increase in direct labor costs will have a corresponding increase in indirect labor expense. Indirect labor expense is an overhead which is applied only to the direct labor expense. The ratio between the original estimate of direct labor and indirect labor is approximately the same after the increase in labor expense.

7.6.3 See Response to DRA-OCE Data Request #4 (Question 3)

Honor Rancho (Unbundled Storage Program)

	Table 1 (Original Estimates)	Table 2 (Current Estimates)	Difference (Table 2 vs. Table 1)
AFUDC	$456,181	$2,113,883	$1,657,702
Gross Expenditures	$48,980,157	$60,143,237	$11,163,080
Less: Cushion Gas	(11,535,183)	(6,500,000)	5,035,183
Less: AFUDC	(456,181)	(2,113,883)	(1,657,702)
Capital Expenditures	$36,988,793	$51,529,354	$14,540,561

AFUDC represents the financing costs of Honor Rancho capital expenses during the construction work-in-progress (CWIP) period. The AFUDC amounts in the original estimate (Table 1) and the current estimate (Table 2) were calculated on a consistent basis. The AFUDC rates applied in the project were determined in accordance with methodology described in the Code of Federal Regulations. These rates were applied monthly to CWIP balances to calculate AFUDC amounts. AFUDC calculations ended when the project was completed and all capital expenses were transferred into service.

The difference in AFUDC between the original estimate (Table 1) and the current estimate (Table 2) was caused by a combination of the following:

1) Change in the capital expenditure
   AFUDC is calculated by applying the AFUDC rates to the average CWIP amounts on a monthly basis. As the updated project spending increased over the level estimated in the original filing, the average CWIP amounts also increased, increasing AFUDC slightly.

2) Change in the in-service dates
   In the original estimate, project expenditures were expected to start going into service at the beginning of 2010, and project completion was expected in early 2011. The current estimate reflects a delayed schedule in the spending and in-service dates. The project started going into service at the end of 2010, and the project was completed towards the middle of 2012. The delayed schedule resulted in a longer CWIP period, which caused an increase in the AFUDC amounts.

3) Slightly higher AFUDC rates
The AFUDC rates applied in the original estimate were based on the second quarter 2009 AFUDC rate of 8.26%. The current estimate reflects the actual AFUDC rates from 2009 through 2012; the rate was briefly above 9% in 2012.

7.6.4 The CPCN decision delayed the start of plant construction and drilling by four months, the various delays caused by issues during the drilling and completion of the wells are shown in the original and updated testimony.

7.6.5 The timing of the CPCN decision delayed the start date of the plant construction from April 1, 2010 to August 1, 2010 and delayed the start of the drilling until August 29, 2010. The drilling problems caused the following delays:

C2C – 78 extra days of drilling
C7 – 74 extra days of drilling
C7 – 18-23 extra days to complete the well