**SAN DIEGO GAS & ELECTRIC COMPANY**
**SOUTHERN CALIFORNIA GAS COMPANY**

**PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)**

**(A.15-09-013)**

**(DATA REQUEST ORA-69)**

**Date Requested: February 24, 2017**
**Date Responded: March 22, 2017**

---

## PRELIMINARY STATEMENT

1. These responses and objections are made without prejudice to, and are not a waiver of, SDG&E and SoCalGas' right to rely on other facts or documents in these proceedings.
2. By making the accompanying responses and objections to these requests for data, SDG&E and SoCalGas does not waive, and hereby expressly reserves, its right to assert any and all objections as to the admissibility of such responses into evidence in this action, or in any other proceedings, on any and all grounds including, but not limited to, competency, relevancy, materiality, and privilege. Further, SDG&E and SoCalGas makes the responses and objections herein without in any way implying that it considers the requests, and responses to the requests, to be relevant or material to the subject matter of this action.
3. SDG&E and SoCalGas will produce responses only to the extent that such response is based upon personal knowledge or documents in the possession, custody, or control of SDG&E and SoCalGas. SDG&E and SoCalGas possession, custody, or control does not include any constructive possession that may be conferred by SDG&E or SoCalGas' right or power to compel the production of documents or information from third parties or to request their production from other divisions of the Commission.
4. A response stating an objection shall not be deemed or construed that there are, in fact, responsive information or documents which may be applicable to the data request, or that SDG&E and SoCalGas acquiesces in the characterization of the premise, conduct or activities contained in the data request, or definitions and/or instructions applicable to the data request.
5. SDG&E and SoCalGas objects to the production of documents or information protected by the attorney-client communication privilege or the attorney work product doctrine.
6. SDG&E and SoCalGas expressly reserve the right to supplement, clarify, revise, or correct any or all of the responses and objections herein, and to assert additional objections or privileges, in one or more subsequent supplemental response(s).
7. SDG&E and SoCalGas will make available for inspection at their offices any responsive documents. Alternatively, SDG&E and SoCalGas will produce copies of the documents. SDG&E and SoCalGas will Bates-number such documents only if SDG&E and SoCalGas deem it necessary to ensure proper identification of the source of such documents.
8. Publicly available information and documents including, but not limited to, newspaper clippings, court papers, and materials available on the Internet, will not be produced.

9. SDG&E and SoCalGas object to any assertion that the data requests are continuing in nature and will respond only upon the information and documents available after a reasonably diligent search on the date of its responses. However, SDG&E and SoCalGas will supplement its answers to include information acquired after serving its responses to the Data Requests if it obtains information upon the basis of which it learns that its response was incorrect or incomplete when made.
10. In accordance with the CPUC's Discovery: Custom And Practice Guidelines, SDG&E and SoCalGas will endeavor to respond to ORA's data requests by the identified response date or within 10 business days. If it cannot do so, it will so inform ORA.
11. SDG&E and SoCalGas object to any ORA contact of SDG&E and SoCalGas officers or employees, who are represented by counsel. ORA may seek to contact such persons only through counsel.
12. SDG&E and SoCalGas objects to ORA's instruction to send copies of responses to entities other than ORA.

**SAN DIEGO GAS & ELECTRIC COMPANY**
**SOUTHERN CALIFORNIA GAS COMPANY**

**PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)**

**(A.15-09-013)**

**(DATA REQUEST ORA-69)**

**Date Requested: February 24, 2017**
**Date Responded: March 22, 2017**

---

**Subject: Review of Risk Factors for Line 1600 ("The Kiefner Report"), Attachment C.**

**QUESTION 1:**

Provide the model referenced in the Kiefner Report (e.g. referenced at page 2).

**RESPONSE 1:**

SDG&E and SoCalGas (Applicants) object to this question on the grounds that it seeks a model not in Applicants' possession, custody or control and fails to comply with Rule 10.4 of the CPUC's Rules of Practice and Procedure. The model referenced in Attachment C to SDGE-12 Supplemental Testimony of SDG&E and SoCalGas (Kiefner Report) is licensed by Kiefner and Associates, Inc. (Kiefner) from the Northeast Gas Association and is not available to Applicants. Further, terms of the license agreement prohibit distribution of the software to third parties without permission from the Northeast Gas Association.

**Date Requested: February 24, 2017**
**Date Responded: March 22, 2017**

---

**QUESTION 2:**

Provide the copy of the model with the data used in generating the Kiefner Report.

**RESPONSE 2:**

For the reasons set forth in the response to Question 1 above, the entire model cannot be provided. Approximately 150 inputs used by the model are listed in the attachment to this response. The listing also gives the input values used for each case.

**SAN DIEGO GAS & ELECTRIC COMPANY**
**SOUTHERN CALIFORNIA GAS COMPANY**

**PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)**

**(A.15-09-013)**

**(DATA REQUEST ORA-69)**

**Date Requested: February 24, 2017**
**Date Responded: March 22, 2017**

---

**QUESTION 3:**

Provide a copy of the contract under which Kiefner was hired to conduct this report.

**RESPONSE 3:**

Applicants object to this question on the grounds that is calls for information that is protected by the attorney work product doctrine and that it is not admissible in evidence nor reasonably calculated to lead to the discovery of admissible evidence.

**Date Requested: February 24, 2017**
**Date Responded: March 22, 2017**

---

## QUESTION 4:

At page 2, the Kiefner Report states that "The relative risk assessment assumed that the pipelines would be of roughly similar length, traverse similar areas of land use or development, and cross the same or similar hazard zones."

a. Did Kiefner assess if this assumption for the relative risk assessment is correct, given the proposed routing of Line 3602 versus the route Line 1600 takes?

b. Does the relative risk assessment consider potential impact radii of pipelines as defined in 49 CFR Section 192?

## RESPONSE 4:

a. The Kiefner Report made this assumption in order to reduce the analysis to strictly comparing attributes of the existing pipeline and the proposed replacement pipeline that influence the likelihood of failure, independent of location or route-related factors.

b. No, it does not. The relative risk is not true risk expressed as a statistical probability of an event having specified consequence (*i.e.*, the probability of an event causing a specific number of fatalities). The model was developed to enable a pipeline operator to prioritize integrity assessment within designated High Consequence Areas (HCA) based on risk, as required by 49 CFR Part 192, Subpart O. The definition of HCAs leads to the presumption that any failure is unacceptable irrespective of location within the HCA, so consequences of a failure based on location are not part of the risk ranking. Also, for a given pipeline, the potential impact radius usually does not vary from one location to another because the pressure and diameter are usually uniform. "Risk" then is reduced to the likelihood of a failure. The model characterizes that likelihood as a function of how attributes of the pipeline, its operation, and other factors influence susceptibility to, or resistance against, various causes of pipeline failure, considering deterministic mechanisms, historic incident trends, or engineering judgment. The output is expressed as a risk score rather than a probability. The risk score is designed to identify and accentuate differences. It can be used to compare and rank sections of pipe within an HCA having differing attributes, compare the relative susceptibility to failure of multiple HCAs from a pipeline or among different pipelines, or gauge the effectiveness of differing strategies for mitigating threats. Note that there is no reason why the application of the model is limited only to HCAs, the relative ranking concept is still valid.

**SAN DIEGO GAS & ELECTRIC COMPANY**
**SOUTHERN CALIFORNIA GAS COMPANY**

**PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)**

**(A.15-09-013)**

**(DATA REQUEST ORA-69)**

**Date Requested: February 24, 2017**
**Date Responded: March 22, 2017**

---

**QUESTION 5:**

Does the relative risk assessment consider the cumulative risk from Line 1600 derated to 320 psig or less, and Line 3602 in service? If not, explain why not.

**RESPONSE 5:**

No, it does not sum the risk scores from the two pipelines. The risk scores are intended to be comparative for purposes of prioritizing assessment within one or more HCA segments, as well as for comparing the effectiveness of differing preventive or mitigative measures.

---

**QUESTION 6:**

Why did the model "not take credit for the reduction in consequences that would be associated with derating Line 1600 to distribution service" (p. 2)?

**RESPONSE 6:**

De-rating Line 1600 shrinks the potential impact of a rupture of that line but, as explained above in the response to Question 4(b), it is not a consequence-driven model because within HCA segments any failure could have unacceptable consequences.

**QUESTION 7:**

For Figure 4 (p. 9), provide an updated figure that includes a Pipe Fracture Propagation Transition Curve for the materials Line 3602 would be manufactured from.

**RESPONSE 7:**

Applicants' witness, Michael Rosenfeld of Kiefner, has not compiled and analyzed data for new pipe in a similar manner as in Figure 4 of the Kiefner Report. The pipe for proposed Line 3602 would be manufactured to meet the requirements of the current ($44^{th}$) edition of API 5L "Specification for Line Pipe", which specifies impact toughness testing at a temperature of 32 F unless a lower temperature is specified by the purchaser. The minimum shear appearance requirement is 85% at the test temperature. This criterion is generally easily met by modern X65 line pipe. Mr. Rosenfeld's past reviews of numerous mill test reports for modern X52 through X80 line pipe has shown that they typically report 90% to 100% shear appearance at the test temperature, which is sometimes colder than 32 F. As such, Mr. Rosenfeld would expect that a curve of the cumulative probable toughness transition temperatures for such pipe would be far to the left of the cumulative probability curves shown for the AO Smith pipe in Figure 4 of the Kiefner Report.

---

**QUESTION 8:**

Is Kiefner aware of any utilities that have a program to systematically remove or remediate pipelines subject to fracture control? If so, provide the list of utilities and the year in which their programs were initiated.

**RESPONSE 8:**

There are numerous independent operators of gas distribution systems in the U.S., so practices undoubtedly vary among them. Mr. Rosenfeld is unaware of operators that are systematically removing pipe based solely on fracture control criteria, but is aware of pipeline operators that are systematically removing pipe based on perceived risk from a variety of factors including concerns for vintage seam quality, low toughness properties, low-strength welds or pipe joining technology, coatings degradation, corrosion control, and/or an inability to fully assess integrity of the pipe. A very similar case to this one involves ATCO Pipelines, which supplies the cities of Calgary and Edmonton with natural gas. In 2013, ATCO applied for and received permission from the Alberta Utility Board to de-rate urban transmission pipelines in both cities to distribution service and install new transmission pipelines constructed to modern standards. The lines to be de-rated were constructed between 1950 and 1960 using low-frequency electric resistance welded (ERW) seam pipe and had been generally reliable up to that time.

**SAN DIEGO GAS & ELECTRIC COMPANY**
**SOUTHERN CALIFORNIA GAS COMPANY**

**PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)**

**(A.15-09-013)**

**(DATA REQUEST ORA-69)**

**Date Requested: February 24, 2017**
**Date Responded: March 22, 2017**

---

**QUESTION 9:**

Under what conditions would Line 1600 be expected to be subject to “a transition temperature more than 60 degrees F warmer than the expected operating temperature”. (p. 9).

**RESPONSE 9:**

Natural gas pipelines typically operate at the temperature of soil or groundwater at the depth of burial, which might be 55 degrees F to 65 degrees F in the San Diego area. Adding 60 degrees F results in a maximum target maximum transition temperature of 115 F to 125 F to assure ductile fracture initiation capability. Figure 4 of the Kiefner Report shows that approximately 30% of the pipe in Line 1600 will have a toughness transition temperature below that in the pipe body, and 5% of the pipe will have a toughness transition temperature below that in the seam. So under normal operating conditions, 70% of the pipe will have transition temperatures in the pipe body more than 60 F warmer than the operating temperature, and 95% of the pipe will have transition temperatures in the seam more than 60 F warmer than the operating temperature. In other words, most of the pipe may be unable to exhibit ductile fracture initiation under normal operating conditions.

The one low-temperature operating condition that could potentially occur is cooling of the gas downstream of pressure reduction at a regulator. The gas cooling occurs due to the Joule-Thompson effect as the gas expands. This effect can lower gas and pipe temperature to perhaps 30 F for some distance downstream of the regulator. Where that temperature condition prevails, about 90% of the pipe body and 100% of the pipe seams would likely be unable to exhibit ductile fracture initiation.

---

**QUESTION 10:**

Define, in terms of probability, what “greatly reduce the probability of a failure occurring as a rupture” means, as discussed at page 10.

**RESPONSE 10:**

Susceptibility to failure by rupture decreases with operating stress level. If the stress is sufficiently low, a pipe would be expected to leak rather than rupture. This is supported by fracture mechanics studies and industry experience. Leaks are considered to pose less of a hazard than ruptures.

**Date Requested: February 24, 2017**
**Date Responded: March 22, 2017**

---

**QUESTION 11:**

Under what conditions could API 5L Grade X65 and Grade X60 not be expected "to have high fracture toughness with a low transition temperature"? (p. 10).

**RESPONSE 11:**

Modern X60 or X65 line pipe is a high strength low alloy material having a refined microstructure that typically exhibits good ductility at temperatures colder than expected operating temperatures in San Diego. In accordance with API 5L, the pipe must exhibit ductile fracture behavior at a test temperature of 32 F unless a colder test temperature is specified. There is no condition in which a transition temperature that is warmer than the operating temperature for proposed Line 3602 would be expected.

---

## QUESTION 12:

At pages 12 to 13, pressure testing of AO Smith pipe after fabrication is discussed. Is it correct to state then, that the materials used in Line 1600 would have been tested to standards equivalent to those required for the materials proposed to be used in Line 3602? If not, please explain. (Note that this question is not referring to in situ pressure testing after installation, and is referring to mill testing.)

## RESPONSE 12:

The 1951 3rd Edition of API 5LX "Specification for High-Test Line Pipe" specified that the mill test pressure for grades other than X42 be determined so as to produce a hoop stress of 85% of specified minimum yield strength (SMYS) unless otherwise agreed to between the manufacturer and purchases. A.O. Smith was known to routinely test pipe to 90% SMYS, so presumably the flash welded pipe in Line 1600 was tested to that level. Other types of pipe (ERW or seamless) present in Line 1600 may not have been tested to that level. The pipe for proposed Line 3602 would be tested at the pipe mill to at least 90% SMYS.

The mill pressure test is an important indicator of the pipe quality, but today it is neither the only test nor the most effective test of pipe quality. When the pipe for Line 1600 was manufactured, the only way to check the quality of the pipe other than a pressure test was visual inspection. With a 16-inch diameter pipe, the visual inspection could only be performed on the external surface and for a short distance in from each end of the pipe on the internal surface. Flaws not visible to the naked eye were undetectable. So the mill pressure test was the only way to confirm that gross defects were not present. With modern high-strength, high-toughness line pipe, fairly large flaws could withstand a pressure test to a stress of only 90% of SMYS. Modern pipe manufacturing uses various nondestructive examination technologies to detect imperfections that are much smaller than what the mill pressure test can find. Vintage pipe can only be assumed to be as good as the mill pressure test, whereas modern pipe is usually much better than what the mill test can demonstrate. So even if the pressure tests of Line 1600 and proposed Line 3602 pipe were performed at the same percentage of SMYS, the pipe in proposed Line 3602 will be of significantly better quality.

---

## QUESTION 13:

Please confirm that the analysis conducted regarding hook crack failure indicates that hook cracks are not expected to be the likely cause of failure in service for another approximately 100 years, or until 2120 (p. 14).

## RESPONSE 13:

The calculations appear to indicate that a failure due to fatigue in hook cracks or any other defect resident in the seam is unlikely in less than 100 years.  Although the analysis and calculations are thought to be accurate, because of unknowns in the past or future operation, and the potential for interaction with other threats or degradation over time, the results are not represented as assurance that failure could not happen at some earlier time in the future.

**SAN DIEGO GAS & ELECTRIC COMPANY**
**SOUTHERN CALIFORNIA GAS COMPANY**

**PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)**

**(A.15-09-013)**

**(DATA REQUEST ORA-69)**

**Date Requested: February 24, 2017**
**Date Responded: March 22, 2017**

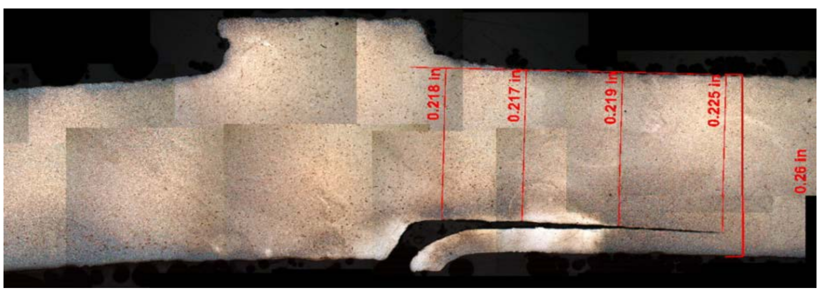
---

**QUESTION 14:**

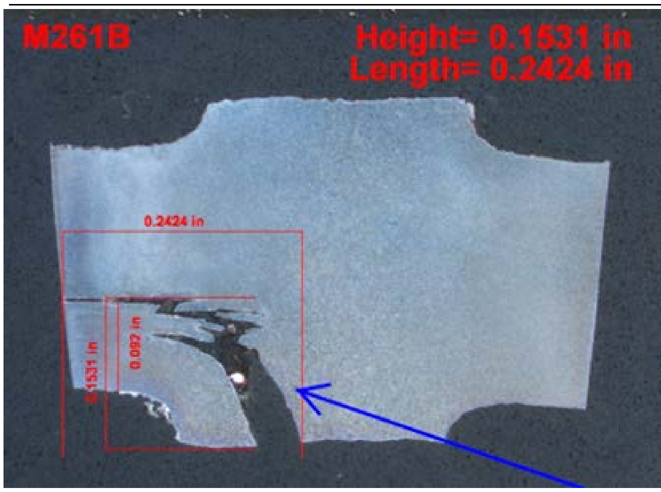
Did Kiefner assess any of the In-Line Inspection data to see if any of the results indicate potential problems as identified by the Pipeline Hazardous Materials Safety Administration (PHMSA) studies (pp. 14-15)?

**RESPONSE 14:**

Kiefner reviewed SDG&E's results from investigative digs. SDG&E identified a number of occurrences of hook cracks several inches long. An example of one in-line inspection (ILI) feature removed from Line 1600 is shown below. This hook crack was present since the day the pipe was manufactured but there is no evidence that it enlarged in service, mainly because the pre-existing lamination that resulted in the hook crack was wide enough to turn horizontally, and the net depth was shallow. While not desirable, it was not an actual integrity threat.




Another example of an ILI feature removed from Line 1600 shows clear evidence of flaw enlargement and possible interaction of multiple embedded discontinuities. It is difficult to know whether it grew during the cold expansion step in the pipe forming process, the pipe mill pressure test, or in service, but evidently the only thing stopping the growth was when the aggregated flaw intersected a lamination. The lamination was positioned at a depth of about 37% of the pipe wall so the remaining ligament experienced stresses in service that were enhanced to approximately 1/(1-0.37)x100 = 159% of nominal stresses.




The circumferential magnetic flux leakage (CMFL) ILI tool is better able to detect hook cracks on the inside than on the outside, and consistent with this performance bias, appears to have identified hook cracks located only or predominantly on the inside surface. There is no reason why hook cracks would form preferentially on the inside, although some external hook cracks might have been discovered by visual inspection at the pipe mill. Also, there was no report of false positive indications of seam features, which suggests that the detection or reporting threshold was not low enough. These outcomes suggest that another ILI technology will need to be implemented to rid the pipe of crack-like seam features, namely the electromagnetic-acoustic transducer (EMAT) tool. It has been our observation that an EMAT ILI of a pipeline constructed using flash welded seam pipe after a CMFL ILI produces a significant increase in indicated seam features. However, EMAT ILI is more costly to perform, there is a very limited choice of EMAT tools available in a 16-inch size, and EMAT inspection typically results in large numbers of digs to investigate what often turn out to be features of low interest. Nevertheless, if Line 1600 is to remain in transmission service, SDG&E probably should consider performing EMAT ILI if a tool is available that can get through the pipeline intact.

**Date Requested: February 24, 2017**
**Date Responded: March 22, 2017**

---

**QUESTION 15:**

Given the Interstate Natural Gas Association of America (INGAA) and American Petroleum Institute (API) studies of corrosion on pre-1950 pipes, what would explain the lack of corrosion and leaks on Line 1600 compared to similar vintage pipes (pp. 17-18).

**RESPONSE 15:**

The INGAA and API reports do not state that all 1950s vintage pipelines will experience leaks or ruptures due to corrosion, only that the probability of experiencing corrosion-caused failures is demonstrated to be greater than would be the case with a newer pipeline, for several reasons. Line 1600 has a good record with respect to corrosion-caused failures, so far, due to apparently effective management of the threat by SDG&E. But Line 1600 is not immune to corrosion. The in-line inspection for corrosion revealed that many instances of corrosion pitting have occurred. Kiefner has not further analyzed the data to identify trends related to location, external features like casings or sources of interference with the cathodic protection system, or changes in corrosion condition over time.

---

**QUESTION 16:**

In Kiefner's analyses, were there any records of problems associated with stream and river crossings identified for Line 1600 (pp. 19-20)?

**RESPONSE 16:**

SDG&E did not report problems associated with stream and river crossings, but that does not imply that those crossings cannot pose a hazard. We actually performed a preliminary comparison of Line 1600 with proposed Line 3602 risk associated with water crossing hazards using the risk model but did not present the results because we did not have complete information about the number, sizes, and flooding tendencies of the crossings. PHMSA has issued advisory bulletins about river crossings due to frequent occurrences of pipeline failures in rivers due to flooding. Pipelines installed across rivers by trenching (which would be the case for Line 1600) are considered to have a higher risk for failure than those installed by directionally drilling. It also appears that Line 1600 may cross what are identified as potential soil liquefaction zones that could pose a secondary seismic hazard, but we did not have time to study that concern in detail.

---

**QUESTION 17:**

Did Kiefner assess the number of 811 ticket requests along the proposed route for Line 3602 (p. 23)? If so, how many ticket requests have there been along the proposed route each year within the last 10 years? If not, please explain why not.

**RESPONSE 17:**

In the time available, we were only able to obtain information about line locate requests with respect to Line 1600 for the past 3 years. All buried pipelines are exposed to the integrity threat of excavator damage.

**Date Requested: February 24, 2017**
**Date Responded: March 22, 2017**

---

## QUESTION 18:

Based on the information provided to Kiefner, does Line 1600 have more, less, or equivalent cover to today's common practices (p. 24)? To the extent this information is provided in testimony or workpapers, provide a reference to the materials Kiefner used.

## RESPONSE 18:

We did not have depth of cover data for Line 1600. Depth of cover was not addressed in applicable standards for the design and construction of pipelines at the time that Line 1600 was installed. Shallow cover is a known potential concern for older pipelines, due to loss of cover from wind and water erosion, farming activity, and land development, and older pipelines often were not buried as deeply as modern pipelines to begin with. The minimum depth of cover is specified in 49 CFR 192 and it is a common practice today to install a pipeline more deeply than the specified minimum as a way of reducing the chances of incidental excavator contact, especially in developed areas and where other buried utilities are already present. Exact positioning of a new pipeline in the vertical and horizontal directions can be geolocated with high resolution during construction. The real problem with shallow cover is not that it is shallow but that it is unknown. Exact positioning of old pipelines often is not known as precisely as with new pipelines. The combination of inexact knowledge of alignment and incomplete knowledge of depth increases the likelihood of the pipe being hit, especially if an excavator decides to bypass the excavator notification program. This is not to state that SDG&E has no idea where or how deep Line 1600 is, but after 68 years some uncertainties are inevitable. Line 1600 will have low inherent resistance to damage from excavating equipment, if it is hit, due to its relatively thin wall and moderate strength grade..

**Date Requested: February 24, 2017**
**Date Responded: March 22, 2017**

---

## QUESTION 19:

Given that Line 1600 has, and can be in-line inspected, how does the information from the In-Line Inspection (ILI) impact the threats identified in the Report? Please identify each threat that is impacted, and state how the impact would be re-stated given the information from the ILI.

## RESPONSE 19:

Please refer to the response to Question 14 above. The ILI did discover indentations, mechanical damage, and corrosion as well.

---

**QUESTION 20:**

What is the basis for a pressure test of 960 psig as an assumption for Figure 11 (p. 26).

**RESPONSE 20:**

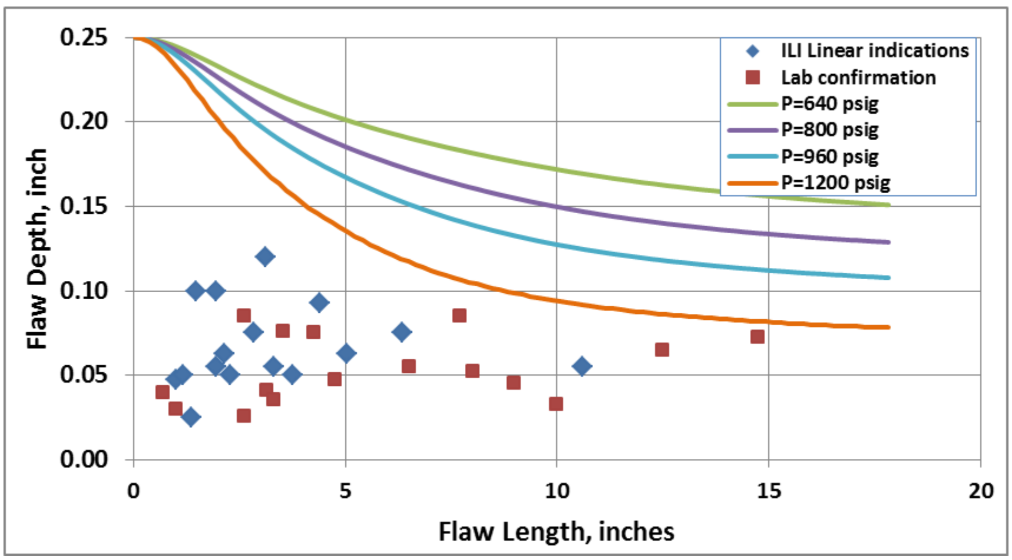
Kiefner was under the impression that the proposed hydrostatic test pressure was 960 psig.

**QUESTION 21:**

Provide an updated version of Figure 11 that includes a pressure test of 1200 psig.

**RESPONSE 21:**

Below is Figure 11, which includes a pressure test of 1200 psig for purposes of this data request response.



**SAN DIEGO GAS & ELECTRIC COMPANY**
**SOUTHERN CALIFORNIA GAS COMPANY**

**PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)**

**(A.15-09-013)**

**(DATA REQUEST ORA-69)**

**Date Requested: February 24, 2017**
**Date Responded: March 22, 2017**

---

**QUESTION 22:**

Explain what is meant by “the hook cracks discovered in Line 1600 opened widely” (pp. 26-27)?

**RESPONSE 22:**

SDG&E cut out some of the hook cracks for metallurgical examination. Most of them were pulled open during the mill test. An example is shown in the first figure in response to Question 14 above.

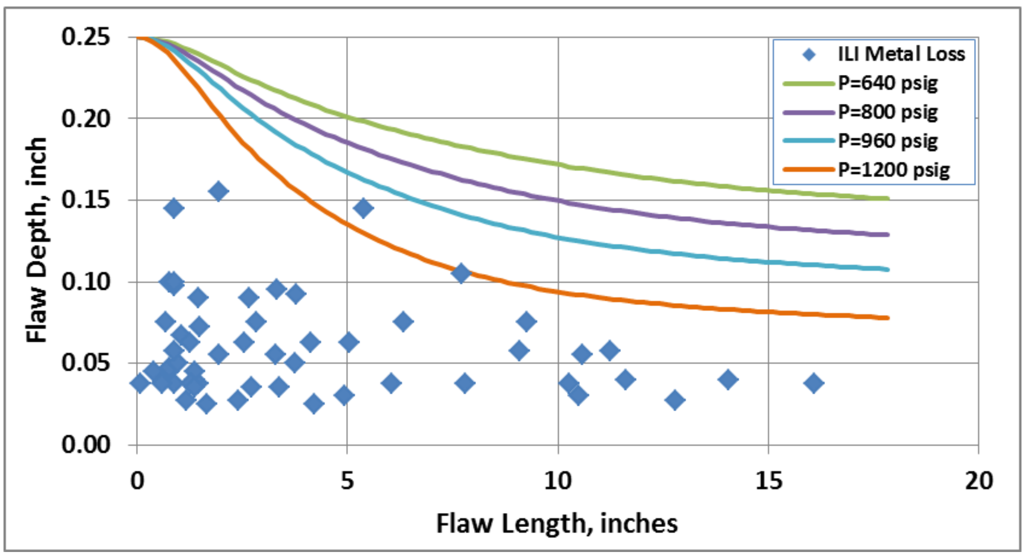
The significance of the hook cracks being opened widely is that a seam defect must have a minimum gap of about 0.5 mm to be reliably detectable by a CMFL ILI tool. The CMFL tool cannot be relied on to detect cracks that remain tight including growing fatigue cracks.

**QUESTION 23:**

Provide an updated version of Figure 13 that includes a pressure test of 1200 psig.

**RESPONSE 23:**

Below is Figure 13, which includes a pressure test of 1200 psig for purposes of this data request response.



---

**QUESTION 24:**

When Line 3602 is pressure tested, assuming it goes into service, would closing roads and evacuating houses during testing still be recommended (p. 28)?

**RESPONSE 24:**

Because of the improved methods for examination during the manufacturing of new pipe and during the construction of new pipelines today, the likelihood of a test break is much lower than with either testing a new pipeline at the time that Line 1600 was built or testing Line 1600 today. However, test breaks do still occasionally happen even with new pipeline construction. Whether to recommend evacuation of houses or to close roads is most appropriately determined as part of the detailed planning of each hydrotest depending on the specifics of the given hydrotest. Some of the factors that will influence this decision are relative location of people and property to the actual pipeline being tested, the characteristics of the pipe being tested and the stress level to be imposed on the pipe during the test.

**SAN DIEGO GAS & ELECTRIC COMPANY**
**SOUTHERN CALIFORNIA GAS COMPANY**

**PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)**

**(A.15-09-013)**

**(DATA REQUEST ORA-69)**

**Date Requested: February 24, 2017**
**Date Responded: March 22, 2017**

---

**QUESTION 25:**

Explain the conditions under which “pipelines may experience pressure-cycle induced fatigue crack growth of flaws” (p. 29). Are those conditions expected if Line 1600 is pressure tested? If so, please explain.

**RESPONSE 25:**

The potential for fatigue crack growth occurs if large initial flaws are present and the pipeline experiences numerous pressure cycles. ILI has shown that large flaws are present in Line 1600, but crack-growth analysis has shown that the rate of fatigue crack growth in Line 1600 is slow based upon its historical operation. Performing a pressure test essentially “restarts” the clock on fatigue crack growth, if the test is performed at a higher pressure than a prior test or is at least at a high enough level to eliminate flaws that could have been enlarging while in service. A hydrostatic pressure test does not eliminate future fatigue crack growth of whatever flaws survive the test.

**QUESTION 26:**

If a different diameter pipe was selected for proposed Line 3602 (other than 36”), how would this impact the model results (starting at p. 29).

**RESPONSE 26:**

There is a mathematical relationship between pipe diameter, wall thickness, SMYS, and design pressure. For a given design pressure in a location class, a change in diameter would not be made independently of changes in the other pipe parameters, each of which can influence the likelihood of a failure occurring due to some cause and therefore the model’s risk score. If the diameter is reduced, the wall thickness will be reduced and possibly SMYS would be reduced. The changes would reduce real resistance to corrosion, mechanical damage, and other outside forces, and an increase in risk scores in the model.

---

## QUESTION 27:

Please confirm that the Line 3602 proposals by SCG/SDG&E meet the attributes used in the model (pp. 29-30). If the attributes used differ from the proposed Line 3602, please explain how and why.

## RESPONSE 27:

The analysis for proposed Line 3602 considered the pipe grade, diameter, wall thickness, and operating pressure that were reported to Kiefner as the intended parameters for proposed Line 3602.

---

**QUESTION 28:**

Are the risk model results additive (p. 30)? By additive, does this mean that the proposal to reduce pressure on Line 1600 to 320 psig or less, plus the addition of the proposed Line 3602 would have a combined score of approximately 7? If not, please explain and provide the relative risk of the SCG/SDG&E proposal for both Line 1600 to remain in service and for Line 3602 to be constructed.

**RESPONSE 28:**

This is answered in the response to Question 5 above. The model was intended to provide comparative rankings of segments within an HCA, or between two pipeline configurations, or to gauge the effectiveness of preventive and mitigative measures. Risk scores of differing pipelines are comparative, not additive.

**Date Requested: February 24, 2017**
**Date Responded: March 22, 2017**

---

**QUESTION 29:**

If Line 1600 was replaced in situ, would it be expected to have a risk score approximately equivalent to the “New Line 3602” entry in Figure 14 (p. 30)?

**RESPONSE 29:**

Yes, assuming that it is feasible to do so and if it is replaced in-situ with a line having the same attributes as what are proposed for Line 3602. The analysis did not consider differences associated with different locations of the two pipelines. See also the response to Question 26 above regarding the effect of pipeline diameter.

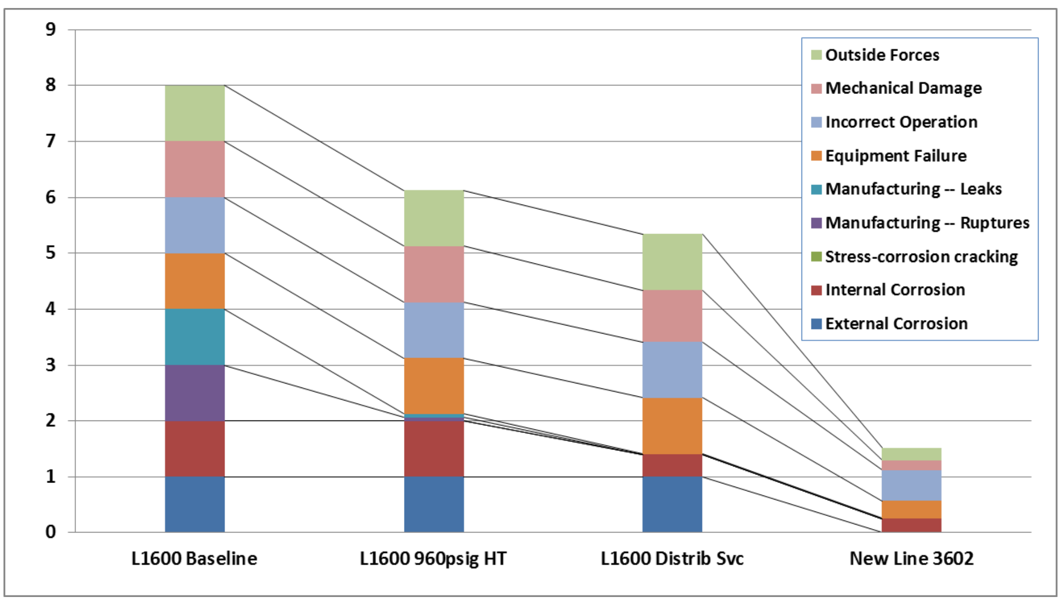
## QUESTION 30:

a. Provide a copy of Figure 14 that is 2 dimensional, rather than 3 dimensional.

b. Provide an Excel spreadsheet that contains each of the underlying data points used to generate Figure 14.

## RESPONSE 30:

a. Below is Figure 14 that is 2 dimensional, rather than 3 dimensional.




b. The following table provides the numerical values in the chart.

| | L1600 Baseline | L1600 960 psig Hydrotest | L1600 Distribution Service | New Line 3602 |
|---|---|---|---|---|
| External Corrosion | 1.00 | 1.00 | 1.00 | 0.000 |
| Internal Corrosion | 1.00 | 1.00 | 0.400 | 0.24898 |
| Stress-Corrosion Cracking | 0.00 | 0.00 | 0.00 | 0.00 |
| Manufacturing -- Leaks | 1.00 | 0.0625 | 0.00335 | 0.00244 |
| Manufacturing -- Ruptures | 1.00 | 0.0611 | 0.00833 | 0.00444 |

| | L1600 Baseline | L1600 960 psig Hydrotest | L1600 Distribution Service | New Line 3602 |
|---|---|---|---|---|
| Equipment Failure | 1.00 | 1.00 | 1.00 | 0.31481 |
| Incorrect Operation | 1.00 | 1.00 | 1.00 | 0.55000 |
| Mechanical Damage | 1.00 | 1.00 | 0.92764 | 0.17440 |
| Outside Forces | 1.00 | 1.00 | 1.00 | 0.22368 |

**SAN DIEGO GAS & ELECTRIC COMPANY**
**SOUTHERN CALIFORNIA GAS COMPANY**

**PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)**

**(A.15-09-013)**

**(DATA REQUEST ORA-69)**

**Date Requested: February 24, 2017**
**Date Responded: March 22, 2017**

---

**QUESTION 31:**

Confirm that, due to the relative nature of the model Kiefner used, that a value assigned to any of the items in Figure 14 has no particular meaning or probability of failure associated with it.

**RESPONSE 31:**

The scoring method was calibrated against the frequency of occurrence of actual reportable pipeline incidents to the extent that data on variables were available. However, the risk scores do not relate directly to specific numerical probabilities of failure.

---

**QUESTION 32:**

Why does the Figure 14 hydro test of Line 1600 use a pressure test of 1200 psig, as compared to elsewhere where a pressure test of 960 psig is used?

**RESPONSE 32:**

This appears to be an inconsistency due to a miscommunication. The correct pressure test should be 960 psig and will be corrected in evidentiary hearings. The analysis was redone using a test pressure of 960 psig. As expected, there was less of a risk reduction than with a test pressure of 1200 psig but the change in risk score was very small, mainly due to the fact that SDG&E has also performed in-line inspections. The revised figure provided to the response to Question 30 reflects this correction.

---

**QUESTION 33:**

Provide all documentation supporting the conclusion that "it is noted that these results are consistent with the conclusions from the PWC cost-effectiveness study" (p. 31)?

**RESPONSE 33:**

The executive summary of the Pricewaterhouse Coopers (PwC) Cost-Effectiveness Analysis (CEA) states the following:

- "The lowest net cost project, the Hydrotest Alternative, was ranked among the lowest in terms of project benefits";
- "The Proposed Project and the Alternate Diameter Pipeline (42-inch) are ranked highest in terms of benefits …";
- "In terms of benefits, the Proposed Project scored higher than the four other Alternatives that also ranked in the net cost range of $225 million to $260 million";

Section V of the PwC analysis compared the benefits of several alternatives including pressure testing Line 1600 and retaining it in transmission service, or derating Line 1600 along with several variants of constructing a new transmission line (having differing sizes or routes). The benefits considered safety, evaluated in terms of:

- increased safety margin against rupture by derating Line 1600;
- the ability of the pipeline to safely sustain degradation due to corrosion, manufacturing anomalies, and excavation damage;
- the operator's ability to be aware of degradation conditions;
- expected reduction in incidents per mile of pipeline within HCAs; and
- timeline for achieving CPUC's directive to pressure test or replace transmission pipelines that had not been subject to pressure testing.

PwC developed a relative risk ranking model consisting of numerical scores for each safety benefit component. The proposed project ranked better than pressure testing Line 1600 and maintaining it in transmission service in every category except the timeline for meeting the CPUC directive (in which they were tied). The ranking is summarized in Table 11 of the PwC report. The supporting discussion for the scoring then followed. While Kiefner's risk ranking model and PwC's safety ranking methods differed they arrived at a similar conclusion, which is that the proposed Line 3602 would lower the net risk or enhance net safety compared with testing Line 1600 and maintaining it in transmission service.