ATTACHMENT C

to the Supplemental Testimony of SDG&E and SoCalGas (February 2017)

Review of Risk Factors for Line 1600

San Diego Gas & Electric Company

Final Report No. 17-029

Review of Risk Factors for Line 1600

Michael J. Rosenfeld, PE

February 20, 2017

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on

REVIEW OF RISK FACTORS FOR LINE 1600

to

SAN DIEGO GAS & ELECTRIC COMPANY

February 20, 2017

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INTRODUCTION

San Diego Gas & Electric (SDG&E) Line 1600 is a 16-inch outside diameter (OD) natural gas transmission pipeline constructed in 1949 and operating historically with a maximum allowable operating pressure (MAOP) of 800 psig. It runs approximately 50 miles from the Rainbow Metering Station in northern San Diego County into the city of San Diego. The pipeline primarily consists of flash welded seam pipe meeting API 5LX Grade X52, along with some pre-1970 electric-resistance-welded (ERW) seam pipe.

In response to the 2010 failure of a Pacific Gas & Electric (PG&E) 30-inch OD natural gas transmission pipeline in San Bruno, CA that was installed in 1956, the California Public Utilities Commission (CPUC) required that natural gas pipelines that lack documented hydrostatic pressure tests performed after installation which support the MAOP either be tested to modern standards or be replaced.[1] SDG&E has no documentary evidence that Line 1600 was hydrostatically pressure tested. In fact, Line 1600 was installed several years before the State of California required pressure testing as part of the pipeline commissioning process (in 1961),[2] and before such practices were adopted in the gas pipeline industry. SDG&E therefore faces a choice between pressure testing Line 1600 to present-day requirements or replacing it. Either response constitutes a major undertaking. Thus SDG&E is compelled to carry out thorough analyses of expected costs and benefits associated with these two choices and potential variations and alternatives in order to identify optimal courses of action.

This report provides an element of SDG&E's optimization analysis by comparing the risk benefits or disadvantages of two specific cases: (a) pressure testing Line 1600 and maintaining it in transmission service, versus (b) derating Line 1600 to distribution service without pressure testing it and replacing its transmission function with a new 36-inch OD pipeline designated Line 3602. Other variations of or alternatives to these paths to meeting CPUC requirements were not considered in this review. Also, this review did not examine matters related to cost, feasibility, or impact on providing continuously reliable service.

[1] CPUC Decision 11-06-017; California Public Utilities Code § 958.
[2] Public Utilities Commission of the State of California, General Order No. 112, Adopted Dec. 28, 1961.

CONCLUSIONS

A review and analysis of risk factors and a risk assessment were performed to evaluate whether it makes sense from a public risk standpoint to pressure test the existing Line 1600, or derate it to distribution service without pressure testing it and build a new 36-inch transmission pipeline, Line 3602. The two options were compared in terms of inherent resistance or susceptibility to certain integrity threats based on typical characteristics and attributes of the two pipelines, historical performance trends affecting similar pipelines, and a relative risk model widely used in the natural gas industry.

The review of risk factors concluded that Line 1600 has greater vulnerability or susceptibility to several key failure mechanisms compared with the proposed Line 3602 including:

- Brittle fracture
- Coating failure and corrosion
- Selective seam corrosion
- Seam manufacturing defects
- Mechanical damage from excavators
- Natural events
- Unknown condition of seams and welds

Susceptibility to several of these factors is reduced in Line 1600 by lowering the operating pressure to distribution service with hoop stress levels below 20% of specified minimum yield strength (SMYS).

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 (e.g. rivers, slopes, soil liquefaction areas). The risk model resulted in risk scores for the option of building the proposed Line 3602 that were meaningfully lower than the option of testing Line 1600 and retaining it in transmission service. The model did not take credit for the reduction in consequences that would be associated with derating Line 1600 to distribution service.

While there is no evidence that Line 1600 is unsafe, there is much that is unknowable about the line, including the ability of girth welds to withstand loadings from natural events, and features in the longitudinal seams. Risk is proportional to what is unknown, at least in part. The proposed Line 3602 will not have such gaps in relevant integrity data. After testing, Line 1600 will still be 68 years old, with limited resistance to many of the above concerns compared with the proposed Line 3602.

BACKGROUND

San Diego Gas & Electric (SDG&E) Line 1600 is a 16-inch outside diameter (OD) natural gas transmission pipeline constructed in 1949 and operating historically with a maximum allowable operating pressure (MAOP) of 800 psig. It runs approximately 50 miles from the Rainbow Metering Station in northern San Diego County into the city of San Diego. SDG&E relies on Line 1600 for 10% of its gas supply and on another pipeline installed in 1961 for the remaining 90%.

The pipeline primarily consists of flash welded seam pipe along with some pre-1970 ERW seam pipe. Both types of pipe are generally regarded as potentially susceptible to integrity concerns related to the pipe manufacturing process, which will be discussed later in this report with respect to the flash-welded pipe as it comprises the largest proportion of the line.

Approximately 95% of the aggregate length of the line consists of pipe having a wall thickness of 0.250 inch, 2% has a wall thickness of 0.312 inch, and small segments have thicker wall. Approximately 97% of the aggregate length of the line consists of pipe designated as API 5LX[3] Grade X52 having specified minimum yield strength (SMYS) of 52,000 psi. In 1949, API 5LX did not provide detailed specifications for grades stronger than X42 and having SMYS of 42,000 psi. Higher strength grades were permitted, subject to agreement between manufacturer and purchaser as to steel chemistry and mechanical properties. Small segments of the line consist of pipe grades having higher or lower strengths than X52.

At the historical operating pressure of 800 psig, the majority of the pipeline operates at a hoop stress of 25,600 psi or 49.2% of SMYS. SDG&E recently reduced the MAOP to 640 psig in order to increase the factor of safety pending completion of integrity assessments by internal inspection. If the line is derated to distribution service, the MAOP will be 320 psig and the hoop stress will be below 20% SMYS.

Line 1600 traverses a wide range of land uses, consisting of 10.0 miles of vacant land, 10.2 miles of agricultural land, 22.6 miles of residential land, 5.2 miles of commercial land, and 1.8 miles of recreational land.

[3] American Petroleum Institute, “Specification for High-Test Line Pipe”, API Standard 5LX, 2nd Edition, May 1949.

TECHNICAL ANALYSIS

The technical analysis consisted of the following steps:

- Review risks to the public posed by natural gas pipelines
- Review risk factors associated with vintage pipelines
- Identify specific risk factors associated with Line 1600 and compare them with proposed Line 3602
- Perform a risk assessment comparing SDG&E's options for responding to the CPUC directive

Discussion of Pipelines and Public Risk

SDG&E's transmission pipelines (including the existing Line 1600 and Line 3602 if it is constructed) are part of a nationwide network of approximately 301,000 miles of pipelines.[4] These pipelines supply a natural gas distribution system consisting of approximately 2.2 million miles of gas distribution mains and service lines to 67.6 million natural gas customers, mostly households. The US transmission pipeline network alone, including 209,000 miles of hazardous liquid transmission pipelines, represents approximately two-thirds of the world's aggregate mileage of transmission pipelines in service and is enough to encircle Earth approximately 12 times. An exact count of the number of people in the US living or working in close proximity to natural gas transmission pipelines is unavailable, but it would be a relatively straightforward exercise to estimate that the number is several tens of millions.

Federal pipeline safety regulations[5] define a natural gas transmission pipeline as a pipeline transporting natural gas at a hoop stress in excess of 20% of the pipe material SMYS, or one that, regardless of the operating stress level, transports gas within a storage field for the purpose of well injection or withdrawal and that is not a gathering line, or transports gas to a large volume customer that is not downstream of a distribution center at which gas supply and gas delivery are demarcated by a block valve. Functionally, a gas transmission pipeline transports gas from a source of supply to a distribution system or an end user.

Of necessity, in order to fulfill its function as suggested above, a transmission pipeline must extend cross-country across lands having a variety of characteristics and uses, including deserts, mountains, rivers, wetlands, farmlands, suburbs, commercial areas, roads and

[4] http://www.phmsa.dot.gov/pipeline/library/data-stats, Annual Report Summary.
[5] Code of Federal Regulations, Title 49 – Transportation, Part 192 – Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, 49 CFR 192, October 1, 2015.

highways, public parks, and urbanized areas. Transporting a flammable gas under pressure through people's yards entails some risk. As stated by the Transportation Research Board's study on transmission pipelines and land use, "Risk can be mitigated but not eliminated".[6] Despite the potential risk, and the San Bruno incident notwithstanding, the industry does a creditable job of managing risk. This is indicated in Figure 1 by the steady decline in annual incidents involving fatalities or injuries caused by all categories of pipelines over time (of which gas transmission pipelines comprise approximately 11%), and in Figure 2 by the very low average numbers of annual fatalities associated with natural gas transmission pipelines in particular.

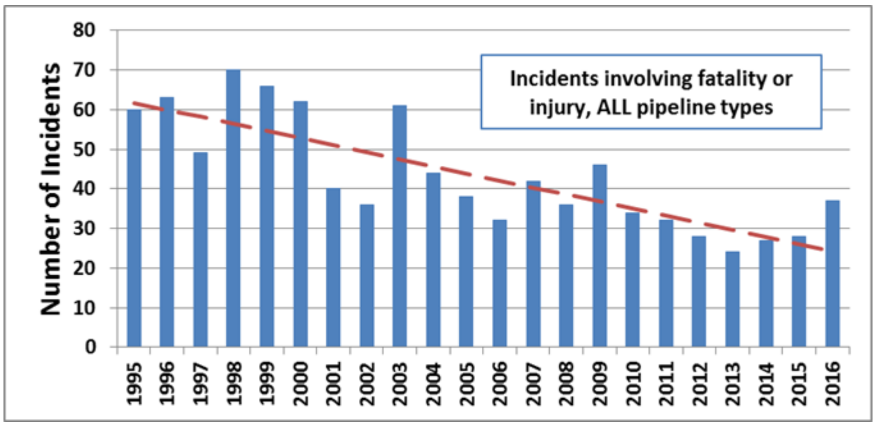

Figure 1. Serious Gas Transmission Pipeline Incidents, 1995-2016

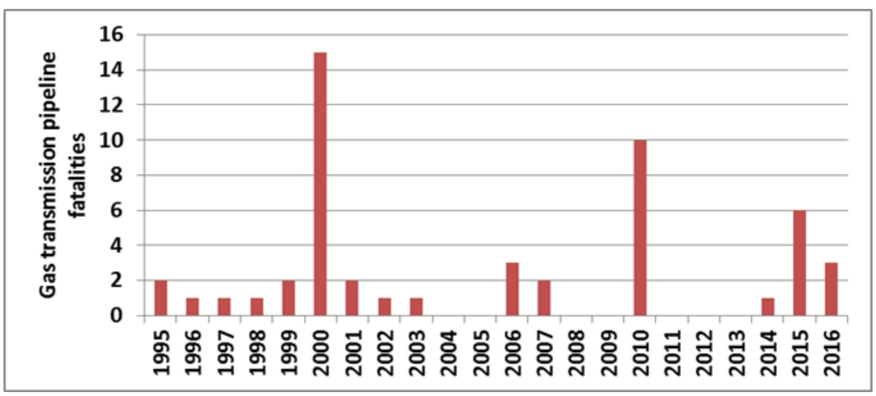

Figure 2. Fatalities Caused by Gas Transmission Pipelines, 1995-2016

Accounting for the expected size of population exposed to gas transmission pipelines, the pipelines pose a low societal risk compared with most other causes of accidental mortality (e.g.,

[6] Transportation Research Board of the National Academies, Special Report 281, "Transmission Pipelines and Land Use: A Risk-Informed Approach", 2004.

traffic accidents, food poisoning, falls).[7] Nevertheless, the public and pipeline safety regulators understandably and reasonably expect that the risk must be managed and maintained as low as reasonably possible. There are several important ways to manage the risk. These include:

- Complying in all phases of design, construction, operation, and maintenance with applicable pipeline safety regulations and industry-developed good practices;
- Identifying segments of pipeline that could impact designated High Consequence Areas in the event of a pipeline rupture;
- Identifying potential threats to a pipeline's integrity considering the pipeline's design, construction, operating conditions, operating environment, and prior history;
- Performing risk assessment in order to identify risk-drivers and to determine locations for prioritizing risk mitigation;
- Conducting assessments of the pipeline condition with respect to integrity threats and in risk-prioritized locations as informed by the risk assessment;
- Developing mitigation strategies to lower risk.

The steps discussed above are the essential elements of "Integrity Management Planning", a formalized process specified under 49 CFR 192, Subpart O. Subpart O requires that "integrity threats" be identified. With reference to ASME B31.8S[8], Subpart O lists and categorizes 21 specific integrity threats based on the causes of reported pipeline incidents. (Pipeline operators are also required to report incidents exceeding specified thresholds of severity.) Integrity threats are categorized as time-dependent if they can worsen over time if nothing is done about them (e.g., corrosion), time-stable if they do not worsen over time provided operating conditions do not change such that the stable condition is no longer stable (e.g., defects in material, welds, or equipment), or time-independent if they occur randomly (e.g., natural events or damage from excavators). The categorization with respect to time affects an operator's choices for integrity assessment and mitigation. Time-dependent threats must be reassessed for periodically; time-stable threats only require a one-time assessment provided conditions do not change over time; while time-independent threats may only be mitigated through prevention and surveillance.

In addition to following these practices, operators are compelled to continually seek opportunities to reduce risk even where a system is deemed to be safe and fit for its intended

[7] National Safety Council, "Injury Facts 2016".
[8] American Society of Mechanical Engineers, "Managing System Integrity of Gas Pipelines", Supplement to ASME B31.8, B31.8S-2016.

service, because safety is achievable at varying levels of risk. Risk may increase with time or it may vary widely depending on specific characteristics of the pipeline, all while the pipeline meets standards of safety.

Some factors that drive risk may be associated with the age of the pipeline. Pipeline age alone is not a determinant of a pipeline's fitness for service, but a prudent operator will recognize that some characteristics or features associated with older vintage pipelines inherently pose greater risk than the corresponding characteristics in a modern pipeline. Furthermore, an absence of failures or problems in service up to this point in time due to any particular cause should not be interpreted to mean that a risk of failure due to that cause does not exist. Thus replacing older pipelines on a selective basis can lower risk. How this is the case with Line 1600 is discussed below.

Vintage Pipeline Concerns

Line 1600 is now 68 years old. It is 21 years older than the current average age of gas transmission pipelines in the US. The percentage of natural gas pipeline mileage in the US by decade of installation is shown in Figure 3.[9] Approximately 11% of the pipeline infrastructure was installed prior to 1950. Thus Line 1600 is older than approximately 89% of natural gas transmission pipelines currently in service in the US today.

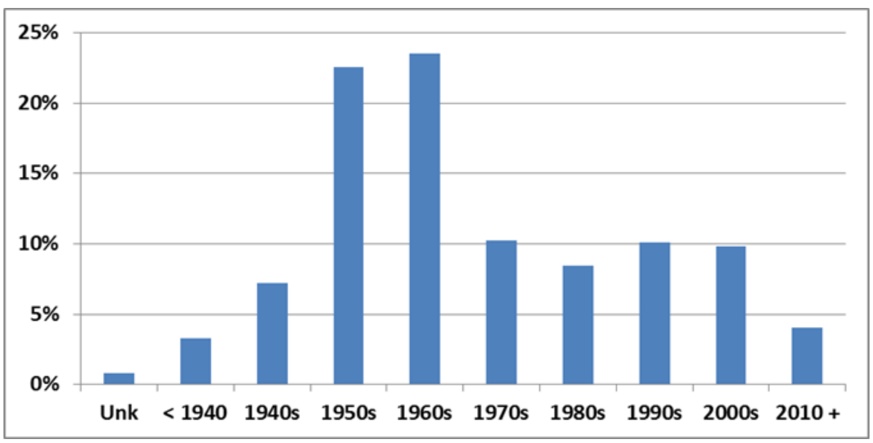

Figure 3. Percentage of Gas Transmission Pipelines by Installation Decade

The age of a pipeline is not a direct determinant of its fitness for service. Fitness for service is determined by how well the pipeline is maintained and defended against degradation or damage by various causes, mostly external in nature. However, age may indirectly affect susceptibility to specific degradation mechanisms owing to inherent limitations or inferiorities of technology associated with the pipeline era of construction, compared with the technology

[9] http://www.phmsa.dot.gov/pipeline/library/data-stats, Annual Report Form 7000.2-1 submittals, 2015.

associated with modern pipelines.[10] These technological areas include (in no particular order) fracture control, pipe manufacturing quality (particularly as it relates to longitudinal seams), girth weld quality and strength, resistance to natural events, resistance to mechanical damage, coatings performance, and capability for being inspected.

These inherent inferiorities do not automatically render older vintage pipelines unsafe; however they do increase susceptibility to or vulnerability to certain integrity threats or increase the difficulty of defending against those threats. This is reflected in higher rates of failure due to specific causes in older pipelines relative to more modern pipelines. Consequently it is accurate to state that a vintage pipeline poses a higher risk to the public than a new pipeline, even as it appears to be in a safe condition. Some vulnerabilities that can be considered applicable to Line 1600 are discussed below.

Fracture Control

At the time that Line 1600 was constructed, it was thought that the primary design concerns were adequate wall thickness and SMYS to operate with a hoop stress within specified limits according to the steel pipe design formula. It became shockingly apparent in 1960 that there could be more to pipeline design than specifying wall thickness and SMYS when a new Transwestern natural gas pipeline experienced a rupture that propagated 8.1 miles while being gas tested. About that time, a Michigan-Wisconsin gas pipeline experienced a 3-mile long rupture. The pipe involved in these incidents met requirements for new line pipe at that time.

Many years of research eventually determined that controlling long running fractures in gas pipelines requires that the pipe material exhibit ductile fracture properties of sufficient magnitude at the operating temperature. Since 1992, industry standards[11] have required specifying and testing gas transmission line pipe materials for 16-inch and larger pipe operating at a hoop stress of 40% SMYS or greater in order to assure that they possess adequate propagating fracture control properties.

The pipe installed in Line 1600 was not manufactured with fracture control in mind because the concept was not known at that time. While the pipe has good mechanical strength, its propagating fracture control properties do not meet modern criteria for gas transmission pipelines. Specifically, the temperature at which one would expect to observe 85% shear

[10] Kiefner, J.F., and Rosenfeld, M.J., "The Role of Pipeline Age in Pipeline Safety", Interstate Natural Gas Association of America, INGAA Final Report No. 2012.04, November 8, 2012.
[11] American Society of Mechanical Engineers, "Gas Transmission and Distribution Piping Systems", Section 8, B31 Code for Pressure Piping, B31.8-1992 and subsequent editions.

appearance[12] in the full-scale pipe wall[13] is well above the expected operating temperature of 55 degrees F. Testing of samples removed from Line 1600 show that the pipe body properties are consistent with those observed in Kiefner's data for A.O. Smith Corporation (AOS) flash welded pipe of vintages ranging from 1930 to 1967, Figure 4.

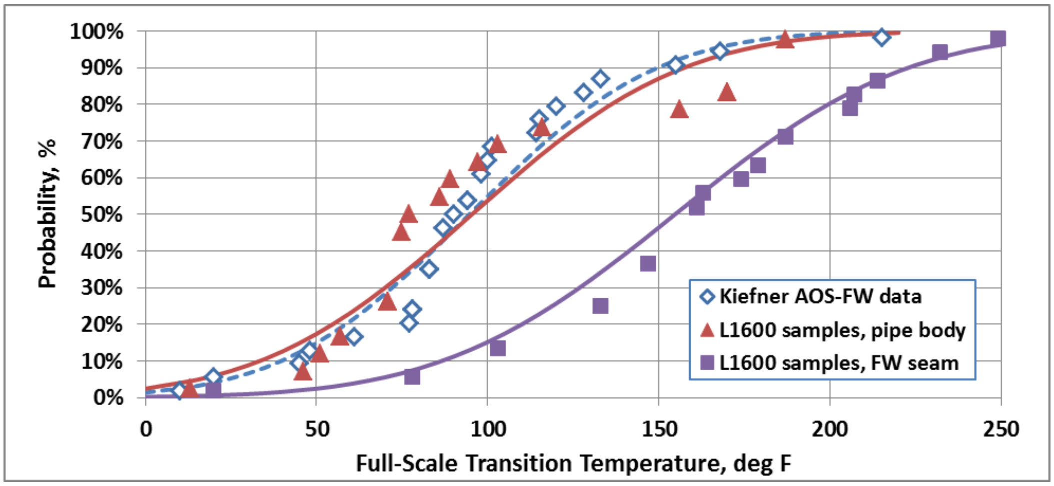

Figure 4. Flash Welded Pipe Fracture Propagation Transition Curves

The pipe body has approximately a 15% probability of exhibiting a fracture appearance transition temperature below an expected operating temperature of 55 degrees F, or put another way, there is an 85% probability that a rupture would propagate some distance. Moreover, there is approximately a 20% probability that the pipe exhibits a transition temperature more than 60 degrees F warmer than the expected operating temperature (or about 135 degrees F) in which case the pipe may be incapable of ductile fracture initiation at the operating temperature. This means that standard corrosion assessment methods would not be reliable for those pipes that cannot exhibit ductile fracture initiation. Charpy V-Notch (CVN) testing of the flash welded seams from the Line 1600 samples exhibited significantly higher transition temperatures than the pipe body, as shown in Figure 4. There is negligible probability of the seams exhibiting ductile propagating fracture characteristics at the expected operating temperature. The implication of these inherent properties of Line 1600 is that in the event of a failure, particularly in the seam but potentially even in the pipe body, a failure would result in a rupture and propagating brittle fracture, rather than a leak.

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[12] A fracture surface that exhibits shear is said to be ductile. The 85% shear appearance temperature corresponds to the lowest temperature at which the full ductile fracture resistance would be expected to be observed in a notched impact test. Modern gas transmission line pipe is specified and manufactured to exhibit the fracture appearance transition temperature at or below the lowest expected service temperature.

[13] The fracture appearance transition temperature is affected by metal thickness. The transition temperature exhibited by CVN specimens that are smaller than 70% of the pipe wall must be adjusted to account for this size effect in order to determine the transition temperature effective in the full-scale pipe wall dimension.

A propagating brittle fracture can be arrested if the material has sufficient fracture resistance, even in the nonductile condition. In the case of Line 1600 operating at 800 psig, the equivalent of 7 ft-lb absorbed impact energy from a full-size CVN coupon at operating temperature is estimated to be sufficient to arrest a propagating brittle fracture. [14] In CVN notched impact tests of several Line 1600 specimens the material exhibited only 10% to 30% shear appearance at a temperature of 50 degrees F, which was substantially nonductile, but the fracture resistance was at least 10 ft-lb full-size equivalent meeting the brittle arrest criterion. The required brittle fracture arrest toughness varies with the square of the hoop stress, so at a reduced MAOP of 640 psig the requirement is less than 5 ft-lb and at the proposed distribution pressure of 320 psig it is only 1 ft-lb. The benefit of reducing the pressure in Line 1600 to distribution service is to greatly reduce the probability of a failure occurring as a rupture. This also reduces consequences in the event of a failure. However, at transmission service pressure, a rupture is more likely and could be expected to propagate the length of at least two pipe joints.

It is important to recognize that the considerations above do not render Line 1600 unsafe. There are thousands of miles of pipeline in service throughout the US that consist of pipe that was not manufactured with fracture control in mind. However, with such pipe, preventing a failure becomes even more important because of the resulting brittle fracture mode of failure. Reducing the operating stress to distribution levels greatly reduces the magnitude of a release, however.

Line 3602 would be constructed from pipe meeting the specifications of API 5L Grade X65, except for one mile of existing pipeline consisting of Grade X60. Modern Grade X65 (and X60) is a high-strength low-alloy (HSLA) steel consisting of a fine-grained microstructure. The pipe body material and seams can be expected to have high fracture toughness with a low transition temperature, and to be capable of meeting brittle and ductile fracture control requirements.

Pipe Manufacturing Defects

The technology of steelmaking and pipemaking has evolved significantly over the past 120 years. Many methods of steelmaking are no longer in use (such as the Bessemer process and open hearth). Likewise, many methods of pipe manufacturing involving certain seam-welding techniques are no longer in use, including lap welding, flash welding, single-submerged-arc welding, and low-frequency-welded electric-resistance welding (LF-ERW). Generally, manufacturing methods go by the wayside because newer developments make it possible to produce pipe faster and at lower cost. However, the industry now recognizes that pipe

[14] Maxey, W.A., Kiefner, J.F., and Eiber, R.J., “Brittle Fracture Arrest in Gas Pipelines”, NG-18 report No. 135, Pipeline Research Council, Inc. Catalog No. L51436, April 1983.

produced using some outmoded steelmaking and pipemaking practices can be susceptible to specific failure mechanisms that warrant special attention.

Certain types of vintage seams have been involved in serious pipeline failures. Consequently, integrity management planning requirements contained in 49 CFR 192, §192.917(e)(4) require that where certain seam types are present, the pipeline operator must consider that an integrity threat associated with the seams is present, and must perform an assessment using a technology capable of assessing seam integrity and seam corrosion. The regulation specifically names lap welded and LF-ERW seams, and any other seam types meeting the screening criteria in B31.8S Paragraphs A-4.3 and A-4.4. B31.8S Paragraph A-4.4 also names LF-ERW and flash welded seam pipe, among others. Thus the type of pipe installed in Line 1600 is of the type that the regulations specify must be presumed to be affected by the seam manufacturing defects integrity threat.

What is flash welded pipe?

It is worth briefly reviewing what flash welded pipe is and why it merits concern. Flash welded line pipe was manufactured by only one company, AOS, from 1930 until 1969. Flash welding is a joining process generally used in industrial manufacturing. Heating is produced by electrical resistance to produce fusion of base materials simultaneously over the entire area of abutting surfaces. The electrical flashing across a gap heats the material to the plastic state. The surfaces are then brought into contact and pressed together to forge a bond.[15] Excess material extrudes lateral to the joint which must then be trimmed. The heating produces a heat affected zone. AOS applied the electric flash weld process to pipe production beginning in 1930. Pipes were produced in 40-foot lengths. Plate was formed in presses in a U and then O configuration. The flash weld process used a 1-million-amp current to heat the mating plate edges over the full length of the pipe.[16] The edges were then bumped together to forge the joint and squeeze out oxides. The bumping action caused excess material to extrude radially to form an upset which was then trimmed not quite flush with the pipe interior and exterior surfaces. The process produced a seam having a characteristic square bead in a width approximately equal to the thickness of the pipe wall, after trimming. Figure 5 shows the external appearance of a flash welded seam on pipe in Line 1600, which is typical of AOS pipe made after 1940. Figure 6 shows the typical appearance of the flash welded seam in cross-section (figure not from Line 1600).[17]

[15] http://www.thefabricator.com/article/tubepipefabrication/comparing-flash-and-butt-welding
[16] A.O. Smith Company, Bulletin 576, 1945.
[17] Rosenfeld, M.J., “Joint Efficiency Factors for A.O. Smith Line Pipe”, www.kiefner.com, December 2012.

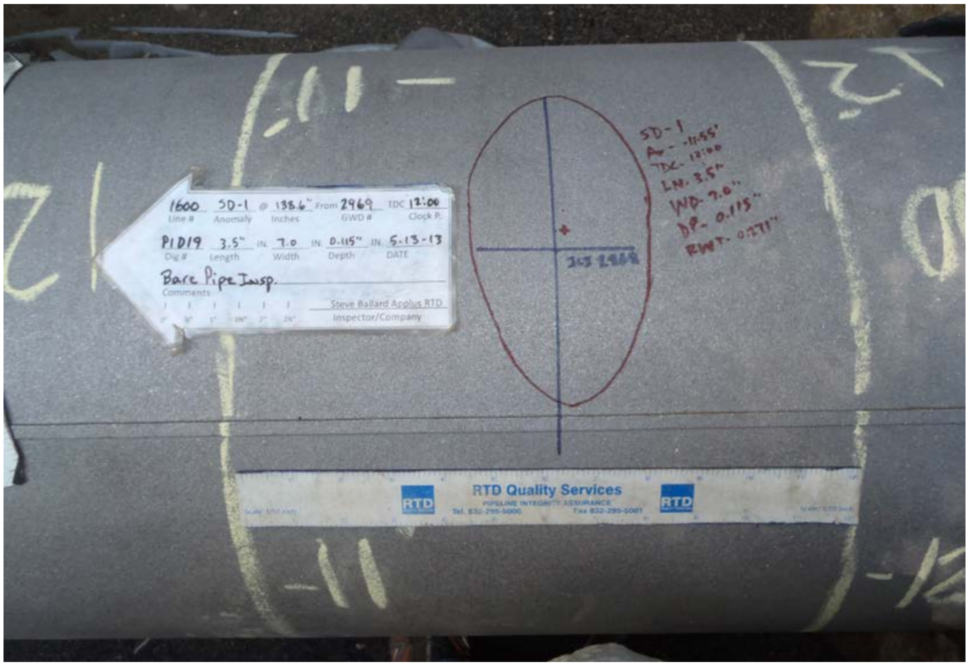

Figure 5. External Appearance of the Flash Welded Pipe Seam on Line 1600

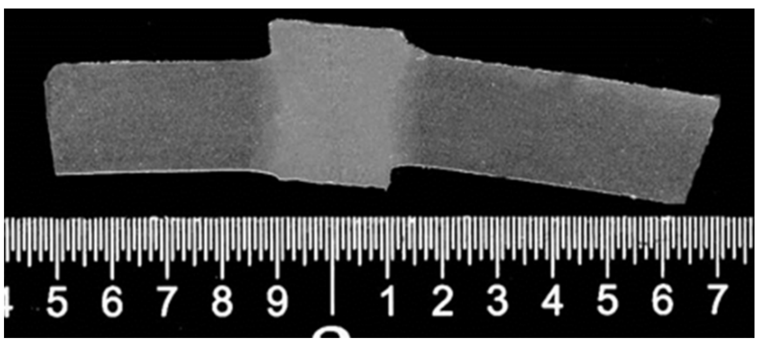

Figure 6. Typical Flash Welded Seam Cross Section, ca. 1946

Starting in 1930 in conjunction with implementing the flash welding process, AOS introduced hydraulic cold-expansion of the pipe (after seam welding). AOS stated in its promotional literature that it used "stronger steel" in their pipe.[18,19] The cold expansion served both to control final dimensions and increase the strength of the pipe, and was a stringent test of the strength of the seam. It is unlikely that a severely defective seam could withstand cold expansion without failing. The amount of expansion was typically 1 to 1.7% of the diameter.

AOS also practiced hydrostatic pressure testing to a high percentage of the SMYS early on. Testing to 90% of SMYS became a standard AOS practice in 1940.[20] For many years, AOS was

[18] Graham, W.T., "Pipe Line Welding", Natural Gas, Nov. 1930.
[19] A.O. Smith, Bulletin 576.
[20] Barkow, A.G., "History of Pipe Line Welding, Part I, 1700-1950", Welding Journal, Vol. 56, No. 9, September 1977.

testing to higher pressure levels than the minimum test levels specified in API 5L or 5LX. Prior to 1942, API 5L only required mill pressure tests to 40% to 50% of SMYS. Starting in 1942, pressure testing of Grades A and B was increased to 60% SMYS; high strength grades of pipe were only required to be pressure tested to 85% SMYS in 1949, and large diameter pipe was not required to be pressure tested to 90% SMYS until 1956.[21] Thus AOS mill testing practices significantly exceeded general industry requirements until 1956. Also, AOS performed burst tests of pipe as a measure of quality control, a practice that was never required in API 5L.[22]

Line 3602 would be constructed using pipe manufactured to meet the present-day requirements of API 5L and 49 CFR 192. The current edition of API 5L requires pressure testing each pipe to a hoop stress of 90% of SMYS at the pipe mill. Pipe of the proposed size will be constructed using double-submerged-arc welded (DSAW) seams. DSAW seams have an excellent record and are not susceptible to the specific types of manufacturing flaws that can occur in flash welded seams.

Hook Cracks

It is likely that the combination of cold expansion and high-level pressure testing enabled AOS flash welded pipe to experience fewer seam-related problems than ERW pipe of similar vintages.[23] Nevertheless, industry experience has been that important seam flaws in the form of hook cracks have been frequently discovered in AOS flash welded seams, and numerous such defects have been identified by SDG&E in Line 1600. (The effectiveness of the inspection process will be discussed later in this report.) Hook cracks result from the use of steel having high sulfur content, which was common at the time Line 1600 was constructed. The sulfur combines with other elements such as manganese to form inclusions or laminations oriented with the layered microstructure in the plane of the plate. Such features in that orientation usually have no impact on the integrity of the pipe. However, if the features are near the edges of the skelp they become reoriented with the plastic flow of material in the upset region adjacent to the bondline of the flash welded seam. Reoriented, they act as a crack which can enlarge in service due to fatigue crack growth driven by operational pressure cycles, eventually resulting in a rupture. A large hook crack in a flash welded seam that extended by fatigue to failure is shown in Figure 7. (This defect is not from Line 1600.)

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[21] Kiefner, J.F., "Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines", Report to DOT and INGAA, Contract No. DTFAAC05P02120, April 26, 2007.
[22] Barkow.
[23] Kiefner, J.F., and Clark, E.B., "History of Line Pipe Manufacturing in North America", ASME CRTD-Vol. 43, 1996.

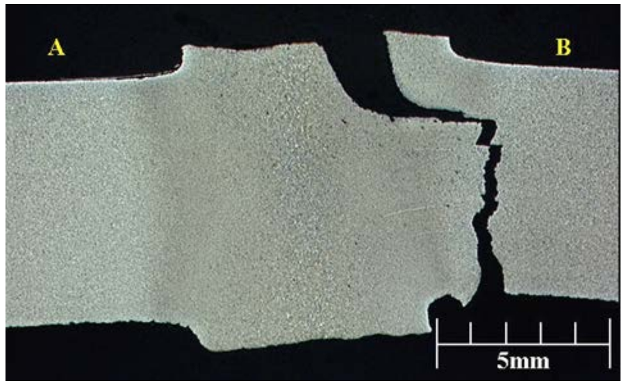

Figure 7. Cross Section of a Flash Welded Seam with a Hook Crack

Kiefner performed an analysis to determine the susceptibility of fatigue crack growth in Line 1600 due to pressure cycles acting on a defect such as a hook crack. The operational pressure fluctuations recorded over time were analyzed to determine the number and magnitude of pressure cycles. Initial flaws of a size that could have just survived the mill pressure test were postulated. The increment of crack growth with each cycle of pressure fluctuation was then determined in accordance with a recognized fatigue crack growth model until the flaw was estimated to be of a size that it could fail in service.[24] The result was a shortest predicted time to failure of 171 years, which suggests that seam fatigue should not be the primary focus of the integrity management plan for Line 1600.

While those results would appear to put concerns for hook cracks to rest, there are some residual concerns that cannot be easily addressed. One is that the estimates of time to failure relied on operating pressure data from 2015 and 2016 and assumed that the pipeline had always operated similarly. Early in its history the pipeline may have operated differently and in a manner that could be more severe from the fatigue standpoint. Secondly, a study of the causes of failures in ERW and flash welded seams performed for the Pipeline Hazardous Material Safety Administration (PHMSA)[25] found that commonly used ductile fracture initiation models gave unsatisfactory (i.e. overestimated) predictions of the failure stress levels of hook crack defects. There was essentially no correlation between predicted and actual failure stress levels. The PHMSA study also found that hook cracks oriented very close to low-toughness bondlines may fail spontaneously in a manner that cannot be predicted with present models and that such an interaction may have happened with a notorious pipeline incident involving ERW seams (the Dixie Pipe Line incident at Carmichael, Mississippi). Finally, multiple hook cracks may be present in parallel or aligned and in close proximity to each other. Recent

[24] Kiefner, J.F., Kolovich, C.E., Zelenak, P.A., and Wahjudi, T., “Estimating Fatigue Life for Pipeline Integrity Management”, International Pipeline Conference, IPC04-0167, Calgary, October 4-8, 2004.

[25] Kiefner, J.F., and Kolovich, K.M., “ERW and Flash Weld Seam Failures”, Subtask 1.4, U.S. Department of Transportation, Agreement No. DTPH56-11-T-000003, September 24, 2012.

research gives evidence that individual hook cracks can interact with other adjacent hook cracks so as to lead to failure in less time than would be expected with a single hook crack.[26] The most adverse combination is hook cracks occurring on the same side of the seam bondline but with one hook crack on the inside and the other on the outside pipe surfaces. With the geometric complexity presented by the flash welded seam bead, it is not entirely clear how well multiple hook cracks are characterized by either in-line inspection (ILI) or in-ditch non-destructive examination (NDE).

Line 3602 would be constructed from DSAW line pipe. DSAW seams are not susceptible to hook cracks.

Selective Seam Weld Corrosion

Flash welded seams are susceptible to an insidious form of corrosion known as selective seam weld corrosion (SSWC).[27] SSWC, also called preferential seam corrosion, is corrosion-caused metal loss, either internal or external, of or along an ERW or flash welded seam. The corrosion process attacks the seam bondline region at a higher rate than the surrounding body of the pipe, resulting in a corrosion crevice or groove aligned with the bondline. Figure 8 shows the typical external appearance of SSWC (at arrow). Figure 9 shows typical selective corrosion in cross section.

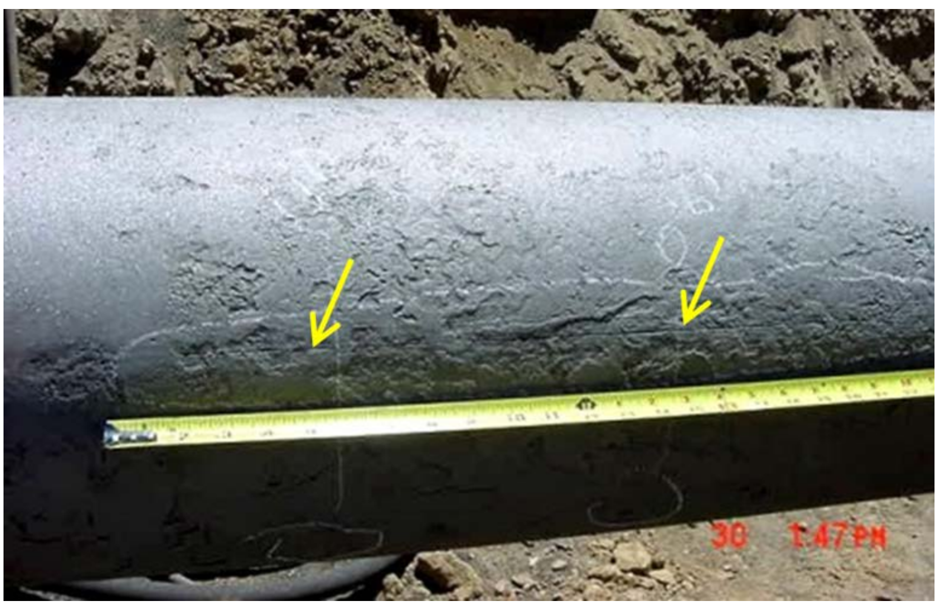

Figure 8. Typical external appearance of selective seam weld corrosion

[26] Ma, J., and Rosenfeld, M.J., "Threat/Anomaly Mitigation Decision-Making Process – Task 5: Deterministic and Probabilistic Approaches for Scheduling Mitigations of Crack-Like Anomalies", Interim Report, US DOT – PHMSA, DTPH5614H00005, July 13, 2015.
[27] Kiefner and Clark.

Figure 9. Selective seam weld corrosion viewed in cross section

Susceptibility to SSWC is enhanced by high sulfur content in the steel,[28,29] similar to the steel used to make the pipe in Line 1600. Steel chemistry analyses performed on samples of pipe removed from Line 1600 indicated sulfur content between 0.02% and 0.05% by weight, which is ten times what would be present in modern line pipe steel. SSWC can evade detection by conventional magnetic ILI tools, but can usually be detected using circumferential magnetic-flux leakage (CMFL) tools. Making accurate measurements in the ditch of the depth of the SSWC groove can be difficult due to the narrow groove geometry and poor reference surface condition. The combination of SSWC and low toughness in the seam bondline, may create a serious defect that is more likely to cause a rupture than coincident corrosion in the body of the pipe, or cause a rupture at low hoop stress.[30] Conventional corrosion evaluation methods such as ASME B31G cannot be reliably used to evaluate SSWC if the flaw cannot be accurately sized or if the seam can exhibit low-toughness behavior. SDG&E has so far not reported the occurrence of SSWC on Line 1600, however the line should be regarded as susceptible based on its chemistry and seam type. With the potential for low seam toughness at the operating temperature, the occurrence of selective corrosion in Line 1600 could pose an integrity concern.

Line 3602 will be constructed using DSAW seam pipe and fusion-bonded epoxy (FBE) coating. It will not be susceptible to selective seam weld corrosion.

[28] Kato, C., Otoguro, Y., Kado, S., and Hisamatsu, Y., "Grooving Corrosion in Electric Resistance Welded Steel Pipe in Sea Water", Corrosion Science, vol. 18, 1978.
[29] Masamura, K., and Matsushima, I., "Grooving Corrosion of Electric Resistance Welded Steel Pipe in Water – Case Histories and Effects of Alloying Elements", Paper No. 75, NACE International Corrosion Forum, Toronto, April 6-10, 1981.
[30] Rosenfeld, M.J., and Fassett, R., "Study of Pipelines that Ruptured While Operating at a Hoop Stress Below 30% SMYS", Pipeline Pigging and Integrity Management Conference, Houston, February 13-14, 2013.

Other Pipe Manufacturing Defects

Pipe produced by AOS has been known to be affected by other undesirable conditions derived from manufacturing. One is excessive hard spots in the pipe body. AOS used pipe with high carbon and manganese content, which causes the steel to be readily hardenable when subjected to high cooling rates. Accidental local rapid quenching of the skelp while hot could then produce hard spots of varying sizes. Hard spots can be susceptible to hydrogen-induced cracking due to hydrogen generated by the cathodic protection system.

AOS pipe may also contain a type of flaw called a lamination. Laminations are the result of high sulfur content in the steel. The sulfur combines with manganese to form soft manganese sulfide inclusions which form very thin discontinuities within the layered microstructure of the plate as it is rolled to final thickness. Usually the laminations are not detrimental to the integrity of the pipe. The installation of hot taps or repairs that are welded to the pipe can encounter difficulties if they intersect a lamination. Also, hydrogen generated by the cathodic protection system can diffuse into the steel and become trapped in the layered discontinuity, leading to the formation of large blisters due to a buildup of pressure. Such blisters may crack and leak over time. SDG&E has not reported encountering this condition.

Corrosion Control

Pipelines buried in soil will corrode with time unless the pipe is externally coated. External coatings provide a primary barrier against corrosion, but coatings are imperfect and can be damaged by many common circumstances including: pipe handling during construction, contact against rocks in the ditch and backfill, stresses induced by expansion or contraction of soils, stresses from soil movement, contact from excavating equipment, or just weathering and deterioration over time. Therefore additional measures are required. Corrosion is an electrochemical process, meaning the flow of electrons is involved. Hence the corrosion process on the pipe exterior can be slowed or stopped by applying a voltage such that electrical current always flows onto the pipe surface where it is exposed to the soil environment at breaches in the coating. This is accomplished by a cathodic protection system utilizing external anodes and/or a rectified external current.

Corrosion inside the pipe may occur where free water collects in low spots where the flow of gas is not vigorous enough to push the water through the line. Cathodic protection is not effective for controlling corrosion inside the pipe. It may be controlled by one or more methods including diligent control of moisture levels in the gas entering the pipeline, use of corrosion inhibiting chemicals injected into the pipeline, or by use of internal cleaning tools propelled by the gas flow to sweep up collected water or residual solid matter deposited on the pipe bottom.

Line 1600 is coated with coal tar enamel. Coal tar enamel has a good performance record but it can weather, crack, disbond, peel, sag, or become penetrated over time. It also can partially shield the pipe from cathodic current. Coal tar enamel has been superseded by more modern coating technologies. The pipeline has been reliable from the standpoint of leaks due to internal and external corrosion. It is cathodically protected and is capable of being internally inspected to detect metal loss caused by corrosion.[31] However, it seems reasonable to expect that the longevity and performance over time of coatings technology that dates from 1949 is likely to be inferior to that of modern coatings materials. Line 3602 would be coated using fusion-bonded epoxy (FBE), a reliable high-integrity coating system. FBE is resistant to disbonding from the pipe surface due to mechanical stress or cathodic overprotection. It also does not insulate or shield the pipe from cathodic current, so it is essentially fail-safe.

The Interstate Natural Gas Association of America (INGAA) pipeline age report determined that pipelines built prior to 1950 exhibit a rate of failure due to corrosion approximately 2.4 times greater than what would be expected based solely on their proportion of total pipeline mileage. On the other hand, modern pipelines constructed since 1990 exhibit on average only 0.25 times the rate expected based on their mileage pro-rata. Thus pre-1950 pipelines are approximately 9.5 times more likely to leak or fail due to corrosion than modern pipelines. A similar conclusion was arrived at in an American Petroleum Institute (API) study of the effects of pipeline age on the safety of petroleum pipelines.[32] That study determined that pipelines built in the 1940s experience leaks due to corrosion at a rate of approximately 1.5 times that of pipelines built between 1970 and 1990 and about 14 times that of pipelines built after 1990. The findings from the API and INGAA studies are consistent, which makes sense considering natural gas and petroleum pipelines are constructed similarly.

Natural Events

Large scale natural events can adversely affect buried pipelines causing damage and sometimes failure of the pipe. Examples of natural events that could occur in San Diego County are listed in Table 1. While the precise mechanisms can vary, events such as those listed in Table 1 or their ensuing secondary effects lead to consistently similar outcomes, namely the introduction of large loads that can cause girth welds to crack or pull apart completely. Other outcomes are possible too. Where loadings in compression are sufficiently severe, the pipe section may buckle. A buckle is usually not an immediately catastrophic event in the way a girth weld separation is, but buckles often develop cracks and eventual leak. Cyclic or oscillatory

[31] Line 1600 is not necessarily capable of accommodating all ILI tools. A recent inspection attempt using a new CMFL tool failed because the tool was unable to negotiate bends and wall thickness changes in the line. The previously used CMFL tool was superseded by the newer tool design and was no longer available. So currently Line 1600 can only be inspected using a conventional MFL tool.

[32] Kiefner, J.F., and Trench, C.J., “Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction”, American Petroleum Institute, December 2001.

movement caused by vortex-induced vibration in water currents flowing across an exposed pipe span can cause fatigue cracks to grow in girth welds which may then pull apart. Several notable pipeline failures have occurred due to that cause. More subtle ground movement, such as undermining by erosion, subsidence, or frost heave/thaw settlement (which is unlikely in San Diego) can introduce axial and bending stresses in the pipe that promote stress-corrosion cracking.

Table 1. Natural Event Hazards That Could Affect Line 1600

Event	Secondary Effect	Effect on Pipeline	Mode of Failure
Heavy rainfall	Flooding, riverbed scouring, exposure of pipeline to water current forces	Lateral displacement of pipeline	Girth weld separation
		Debris build up	Mechanical damage, girth weld separation
		Oscillation due to hydrodynamic effects	Fatigue crack growth leading to girth weld separation
	Slope instability	Axial and lateral displacement of pipeline	Buckling, girth weld separation
	Undermining	Subsidence	Buckling, girth weld cracking, stress corrosion cracking
Seismicity	Fault movement	Axial and lateral displacement of pipeline at a fault crossing	Girth weld cracking, possible separation
	Soil liquefaction	Axial and lateral displacement of pipeline	Buckling, girth weld separation
	Slope instability	Axial and lateral displacement of pipeline	Buckling, girth weld separation

Three sorts of incidents that are often categorized separately are in fact related to natural events: heavy rains and floods, earth movement, and girth weld failures. The reason why girth welds are included is that large external loads are the main cause of girth weld failures,[33] and natural events are the most likely source of large external loads acting on pipelines.

The INGAA pipeline age study determined that pipelines installed prior to 1950 had higher normalized rates of incidents in the heavy rains and floods, earth movement, and girth weld failure categories, while post-2000 pipelines had low normalized rates in the same categories. The ratio of normalized rates shows that pre-1950 pipelines have 1.7 to 3.3 times the rate of incidents due to those causes than do post-2000 pipelines, as shown in Table 2.

[33] The axial stress due to internal pressure in a buried pipeline is nominally only 30% of the hoop stress. Internal operating pressure alone cannot cause even a very weak girth weld to actually separate. Only external loadings can act to pull apart a girth weld.

Table 2. Vintage Pipeline Susceptibility to Failures Caused by Natural Events

Integrity Threat	<1950 Normalized	>2000 Normalized	Ratio <1950/>2000
Heavy rains/floods	2.23	0.67	3.3
Earth movement	1.28	0.77	1.7
Girth welds	1.67	0.80	2.1

The reasons for the increased susceptibility of older vintage pipelines to these three categories of integrity threat have to do with inherent limitations of older methods of pipeline construction, which have been significantly improved upon with modern construction methods. The first has to do with how pipelines used to be installed across flowing streams and rivers. Until 30 years ago (more or less) pipelines were installed across rivers in excavated trenches. The concrete weights were installed on top of the pipe to offset the buoyancy of the empty pipe and the pipe was lowered in and backfilled. Sometimes rock would be placed or dumped over the pipeline. It was difficult to excavate a trench very deeply below the river bottom. Flooding could scour away the river bed exposing the pipe, or if the river overflowed its banks it could carve a new channel exposing a portion of the pipeline that was not part of the actual river crossing and that had been buried to only a normal depth. Today, rivers are routinely crossed using horizontal directional drilling (HDD). An HDD pipeline river crossing is installed by pulling it through a borehole that subtends an arc located very deep below the river bed such that bottom scouring will not expose the pipe. In order to pull the pipe through the borehole the ends of the crossing must be positioned well away from the river banks laterally such that erosion of the stream or river banks will not expose the approach. The HDD pipe is usually heavier wall thickness than the normal construction as well. This installation technique provides better long-term protection for the pipeline and also eliminates the environmental damage caused by excavating a trench across a river. Line 1600 crosses several streams or rivers and was certainly installed in a trench that could be washed out, exposing the pipe. Line 3602 will be installed across rivers and streams using the HDD method.

The second important factor affecting susceptibility to the effects of flooding and soil movement is girth weld quality. As of 1949, radiographic inspection in the field was difficult and expensive. In fact, the technology had only just been introduced for inspecting pipeline girth welds in 1948 and there was a long period of adaptation, learning, and training on the part of the industry to properly take advantage of the technology.[34] At that time the practice was to cut a hole in the pipe to insert the radiological source, until it was concluded that patching the holes was more detrimental than leaving the welds uninspected. X-ray inspection could only be implemented with pipe 20 inches in diameter or larger.

[34] Barkow.

Welding quality is improved by inspection. The first workmanship standard based on radiography of pipeline girth welds was introduced in 1953, four years after Line 1600 was built. Workmanship standards did exist when Line 1600 was constructed but acceptance was usually based on visual examination or destructive examination of random cut-outs.[35] (Visual examination could include several observations capable of detecting a bad weld including burn-off of the electrode, fusion and penetration of the weld, formation and contour of the deposited bead, and sound of the arc. Preparation of the pipe ends for welding, and clamping the pipes to achieve good alignment, also contribute to weld quality. These practices were also just starting to become routine at the time of construction of Line 1600.) Today radiographic inspection of girth welds is a routine practice and can now be performed digitally which is useful for enhancing the image and for long-term retention of the inspection record. Also, where automated welding is practiced (typically with large-diameter long-distance pipelines), automated ultrasonic inspection is used. Sometimes advanced ultrasonic inspection supplements radiographic inspection for critical welds such as tie-ins or transition joints.

Electric arc welds from the era of Line 1600 and even earlier could exhibit favorable mechanical strength and ductility. Present day understanding, as informed by fracture mechanics, is that the ability of a girth weld to withstand large applied stresses is primarily governed by the presence and size of defects,[36,37] i.e. the workmanship. Therefore, whether inspections were performed and to what criteria is the principle discriminator of welds that would be expected to perform well when subjected to significant loadings, e.g. when exposed to the effects of floods, soil movement, or seismic activity. The probability of a weld failing is then the probability of the weld containing defects combined with the probability of the high load event occurring. Thus the threat of girth weld failure can be considered an interacting integrity threat pair: welds of known low quality (or welds of undocumented quality because they were never inspected) and external loadings from natural events are each undesirable but potentially tolerable, but where the two are present together the probability of failure becomes high. This is the situation for Line 1600 wherever geotechnical hazards intersect the pipeline.

Mechanical Damage

Mechanical damage results from the pipe being struck by excavating equipment. The damage is in the form of a scrape or gouge, often within a shallow indentation. Mechanical damage, if severe, may result in immediate failure of the pipe. More often, the pipe initially withstands the damage which may then cause a failure weeks, months, or even years after the damage

[35] Amend, B., "Vintage Girth Weld Defect Assessment – Comprehensive Study", Contract PR-355-094502, Pipeline Research Council, Inc., March 5, 2010.
[36] Reed, R.P., McHenry, H.I., and Kasen, M.B., "A Fracture-Mechanics Evaluation of Flaws in Pipeline Girth Welds", Welding Research Council, Bulletin 245, January 1979.
[37] Lundin, C.D., "Fundamentals of Weld Discontinuities and Their Significance", Welding Research Council, Bulletin 295, June 1984.

occurred. In fact, mechanical damage is one of the most frequent causes of pipeline failure.[38] There is currently no completely reliable method for assessing the severity of mechanical damage. If it is discovered on a pipeline, it is usually considered to be injurious and requiring immediate repair.[39]

The susceptibility of a pipeline to mechanical damage failure has been observed to be significantly greater for older vintage pipelines. The INGAA pipeline age study found that natural gas pipelines installed prior to 1950 were 4.1 times more likely to experience a failure due to being hit by a third-party excavator than pipelines installed after 2000, and 1.7 times more likely to rupture due to latent (previous) damage. The API pipeline age study observed that oil pipelines installed during the 1940s decade were approximately 3.8 times more likely to experience a failure due to being hit by a third-party excavator than pipelines installed after 1990.

The properties of the pipe strongly influence susceptibility to failure in the event that the pipeline is hit by an excavator. Testing and experience has shown that resistance to mechanical damage is proportional to the thickness, toughness, and ultimate tensile strength of the pipe material.[40,41] Older vintage pipelines may exhibit reasonably high strength, but often do not possess the fracture toughness at the operating temperature or heavy wall thickness of modern pipelines. The various combinations of pipe wall thickness and grade present in Line 1600 and the proposed Line 3602 were evaluated for resistance to penetration by excavators, based on a probabilistic mechanics model.[42] The results from applying that model are presented in Table 3. Table 3 shows that Line 1600 could be expected to be severely damaged by most pipeline excavators in use, whereas Line 3602 would resist penetration by almost any excavator.

[38] http://www.phmsa.dot.gov/pipeline/library/data-stats/pipelineincidenttrends
[39] Rosenfeld, M.J., Pepper, J.W., Leewis, K., "Basis of the New Criteria in ASME B31.8 for Prioritization and Repair of Mechanical Damage", Paper No. IPC2002-27122, International Pipeline Conference, Calgary, October, 2002.
[40] Maxey, W. A., "Outside Force Defect Behavior", Battelle Report to A.G.A. Pipeline Research Committee, Catalog No. L51518, August 15, 1986.
[41] Spiekhout, J., Gresnigt, A. M., Koning, C., and Wildschut, H., "The Influence of Pipewall Thickness on Resistance to Damage of Gas Transmission Pipelines", NG-18/EPRG 6th Biennial Joint Technical Meeting on Line Pipe, September, 1985.
[42] Chen, Q., and Nessim, M., "Reliability-based Prevention of Mechanical Damage to Pipelines", PRCI Catalog No. L51816, August 1999.

Table 3. Vulnerability of Line 1600 and Line 3602 to Excavator Damage

Pipe, OD x WT, inches	Grade	Penetration Force, lb	Excavator Weight, tons	Excavators that are Larger, pct.
Existing Line 1600				
16 x 0.250	X52	32,000	23 T	56%
16 x 0.312	X52	42,000	35 T	24%
16 x 0.250	X60	37,000	29 T	38%
16 x 0.250	X42	29,000	20 T	78%
Proposed Line 3602				
36 x 0.625	X65	96,000	147 T	0.03%
36 x 0.500	X60	72,000	86 T	1%

An important factor affecting the threat of mechanical damage is the intensity of land development activity adjacent to the pipeline. Older pipelines are more likely to have recent land development take place nearby that was not planned for when the pipeline route was selected and the line installed. Pipeline operators are required by law in California and all 50 states to participate in an excavation notification program that enables anyone wishing to dig to call a toll-free number (8-1-1) to request that all buried utilities (including water lines, electrical lines, cable or communications, not just pipelines) in the area of the planned excavation to be marked in advance. The operator of the buried utility has 48 hours to respond. It is also a state law that those planning to dig must request the marking in advance and wait for the buried utilities to be marked prior to digging. The number of marking requests ("tickets") for excavations within 1,000 ft of Line 1600, tickets within 10 ft of Line 1600, and tickets requiring direct on-site supervision by SDG&E of excavation near Line 1600 for 2014 through 2016 are presented in Table 4. The intensity of excavation activity near Line 1600 shows no evidence of abating. This risk cannot be understated. Figure 10 shows prior mechanical damage on Line 1600 that was discovered by in-line inspection.

Table 4. Line Locate Requests near Line 1600 2014-2016

Year	Within 1,000 ft	Within 10 ft	Requiring Direct Supervision
2014	1833	65	16
2015	1596	43	27
2016	2003	52	18

Figure 10. Prior Mechanical Damage Discovered on Line 1600

Other factors external to the pipe may affect the likelihood of the pipeline being hit by an excavator in the first place. These include depth of cover, presence of signage or markers, and the accuracy of alignment maps. Older pipelines were often installed with shallower cover than is common practice today. In cultivated areas, plowing activity and wind erosion can reduce the cover over time. HDD installation methods are often used where a new pipeline must cross freeways and other land uses where excavation activity might be expected such that the pipeline depth is well below likely excavation depth.

Discussion of Testing and Inspection of Line 1600

SDG&E has no reliable records indicating that Line 1600 had been pressure tested following construction and prior to entering service, which is consistent with prevailing industry practices.[43] Hydrostatic pressure testing of cross-country pipelines was only first shown to be feasible and effective about a year later. Lacking such a test, SDG&E either must now test the pipeline or replace it in order to comply with the CPUC decision and California statute resulting from the San Bruno incident. For integrity management planning use, 49 CFR 192 recognizes in-line inspection as an acceptable method for assessing the integrity of pipelines covered by Subpart O, irrespective of whether the pipeline had or had not previously been pressure tested, provided the ILI tool is capable of assessing the condition of the pipeline with respect to applicable integrity threats, including seam defects. Unlike some pipelines of similar vintage,

[43] Rosenfeld, M.J. and Gailing, R.W., "Pressure Testing and Recordkeeping: Reconciling Historic Practices with New Requirements", Pipeline Pigging and Integrity Management Conference, Houston, TX, Feb. 14-15, 2013, and Journal of Pipeline Engineering, vol. 12, no. 1, March 2013.

Line 1600 is capable of being internally inspected using ILI tools (though not by all tool types). However, ILI has not been accepted by CPUC for responding to their orders to enhance the safety of pipelines not previously hydrostatically tested.

ILI tools today are complex and sophisticated instruments that are propelled through the pipeline by the flow of gas, and that can sense and record some conditions affecting the pipeline, depending on the design of the sensors installed in the tool. ILI can be more sensitive to some conditions or defects than hydrostatic testing. The types of ILI tools used with natural gas transmission pipelines are listed in Table 5. Not all technologies are available for all pipe sizes or pipeline configurations.

Table 5. ILI Tools Used with Natural Gas Transmission Pipelines

Tool type	Condition Assessed For
Caliper	Significant indentations and diameter restrictions
Geometry with inertial measurement	Same as caliper, plus slope and curvature
Longitudinal (conventional) magnetic flux leakage (MFL)	Internal or external metal loss due to corrosion, some capability for mechanical damage
Circumferential MFL (CMFL)	Selective seam corrosion, some capability for hook cracks
Electromagnetic acoustic transducer (EMAT)	Stress-corrosion cracking

SDG&E has internally inspected Line 1600 using caliper, conventional MFL, and CMFL tools. The CMFL tools are of particular interest in view of the vintage flash welded seams. SDG&E reported no findings of selective corrosion, and numerous indications of hook cracks. The presence and sizes of the flaws indicated by ILI were confirmed by NDE in the ditch using phased-array ultrasonic testing (PAUT). Many of the indicated flaws were then cut out and subjected to destructive examination in order to confirm the accuracy of the PAUT and to characterize the nature of the flaws. The destructive examination confirmed that the linear indications in the flash welded seam were hook cracks.

The CMFL ILI tool performed well in five important ways:

a) a flaw of some type was present where it indicated something was there,

b) it performed according to usual CMFL tool performance claims of 20% of the wall (a depth of 0.05 inch for this pipe),

c) it discovered flaws that were much smaller than would cause the pipeline to fail,

d) it discovered flaws that were smaller than could be discovered by a hydrostatic pressure test, and

e) it indicated the sizes of the flaws reasonably accurately.

These points are illustrated in Figure 11 below.

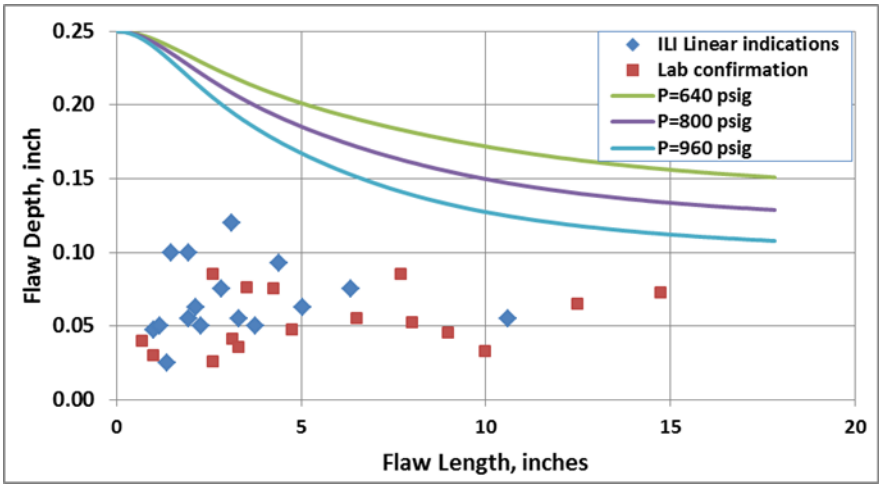

Figure 11. Performance of CMFL Tool for Detecting Hook Cracks

Figure 11 shows the sizes of the hook cracks as reported by the CMFL ILI tool as blue diamond symbols. The sizes of flaws that would fail at an MAOP of 640 psig, an MAOP of 800 psig, and a hydrostatic test pressure of 960 psig are shown as the green, purple, and light blue curves, respectively. That the indicated flaws were smaller than these critical sizes demonstrates that the CMFL tool was capable of detecting flaws that could affect the integrity of the pipe. The dimensions as confirmed by destructive examination are shown as red square symbols. The hook crack dimensions reported by the CMFL tool were in reasonable agreement with the actual dimensions, which is important for discriminating between minor and significant flaws.

On the other hand the CMFL tool exhibited a possible performance limitation: the sizes of flaws that it failed to indicate were approximately as large as the ones that it did indicate, as shown in Figure 12. It is important to understand that no ILI tool indicates all flaws, and both the probability of detection of a flaw and its significance to pipe integrity are proportional to the dimensions of the flaw. On the other hand, as Figure 12 shows, flaws discovered incidentally in the course of investigating the flaws indicated by the CMFL tool were not all substantially smaller than those that were indicated by the tool. After completing a CMFL inspection there will be flaws not reported and not investigated in the field. These incidental flaw discoveries are representative of those that will remain after running the CMFL tool and which will be unknown to SDG&E. Moreover, the CMFL tool requires that some air gap be present at the mouth of a flaw in order for magnetic flux to be sensed. The hook cracks discovered in Line

1600 were opened widely. Hence no CMFL tool vendor claims that the CMFL tool can detect true cracks, and the National Energy Board of Canada (the Canadian counterpart to PHMSA in the US) has denied use of CMFL technology for detecting cracks that could enlarge. A CMFL tool will not indicate hook cracks that remain tight or any part of a hook crack that was growing internally. This represents a risk to the extent that risk is proportional to what is unknown.

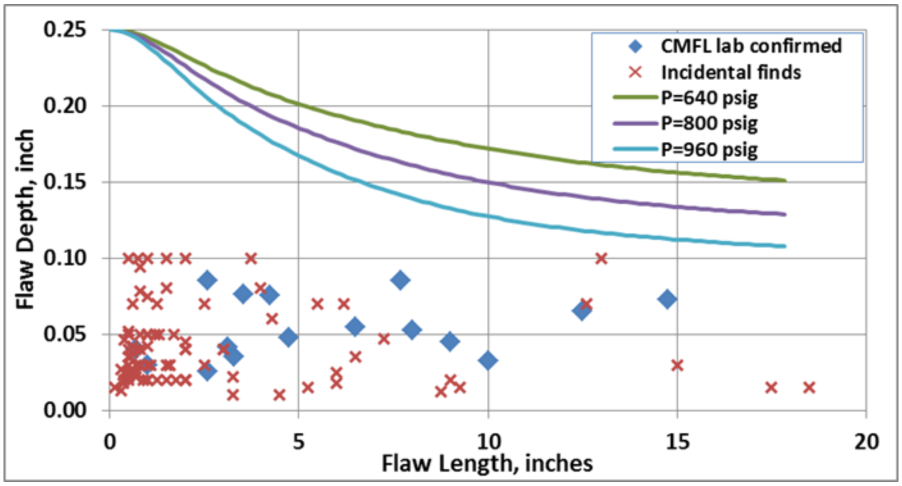

Figure 12. CMFL Indicated and Incidental Seam Flaws

SDG&E performed an inspection for metal loss due to corrosion using a conventional MFL tool designed for that purpose. It appears to have performed well in that it successfully indicated the presence of corrosion flaws that were too small to affect the integrity of the pipe or to be detected by a hydrostatic pressure test, as shown in Figure 13.

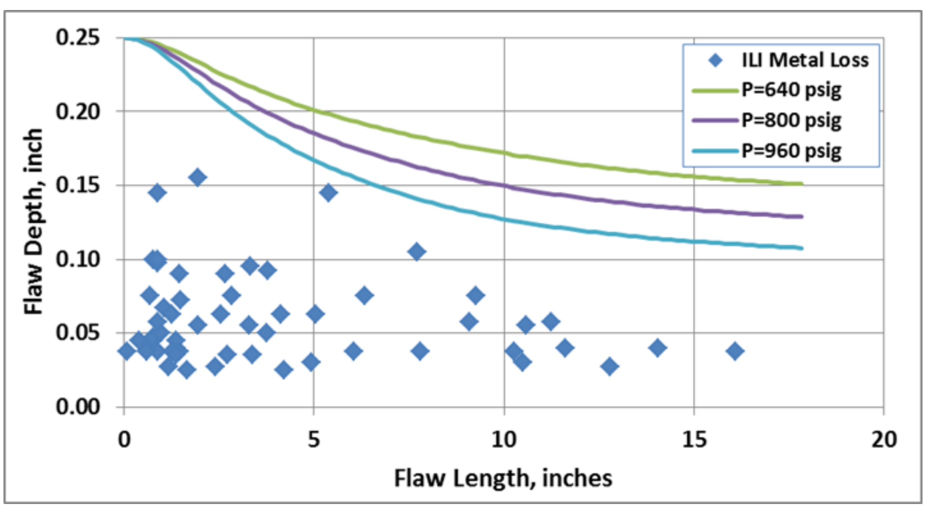

Figure 13. Performance of the MFL Metal Loss ILI Tool

Regarding the prospect of hydrostatic testing, it is important to recognize that a pressure test is a potentially-destructive proof of the integrity of the pipe so there is some risk of one or more failures occurring during the test. This is especially true with an older vintage pipeline that has never previously been pressure tested, although having been subjected to ILI reduces that probability for Line 1600. A test failure is potentially hazardous to people and property nearby. Numerous instances have occurred of property damage, personal injuries, or fatalities as a result of failure of the pipeline being tested or of the testing equipment, even when testing with water. While measures can be taken to isolate the pipeline under test and the testing site in remote areas, this becomes difficult in built-up areas. It may be impossible in some areas to shut down roads that cross or run adjacent to the pipeline. Recent pressure tests of pipelines in California have resulted in damaged roads and vehicles. Line 1600 is situated very close to homes, which probably should be evacuated while the line is being tested.

The proposed Line 3602 will be constructed so as to be capable of being internally inspected using ILI. Present regulations and industry standards require hydrostatic pressure testing of the line before it enters service. Certainly the potential hazard associated with pressure testing exists for Line 3602 as well, but the probability of a single test failure is much lower, let alone multiple test failures, than with a 68-year-old pipe. Finally, it is worth pointing out that after pressure testing Line 1600, it will still be 68 years old with uninspected girth welds, thin wall, and no fracture control.

Discussion of the Risk Benefits of the Proposed Project

Several different pipeline configuration and mitigation alternatives were evaluated on the basis of risk. Information provided to us about Line 1600, two proposed mitigation alternatives, and a proposed pipeline replacement alternative was inputted to the Kiefner-NGA[44] Risk Assessment model to compute probability of failure (POF) index scores. The model is a relative risk ranking model that uses pipeline attribute data to compute index scores that can be ranked. The model includes more input data fields than was available for the existing pipeline and alternatives, so default or estimated data were used where actual pipeline attributes were not available. The values selected for the defaults will influence the actual probability index score, but because the same default values were used for all the segments entered, the default data will not affect the relative ranking of the index scores.

The primary reasons for using the risk model to compute relative probability of failure index scores were 1) to evaluate the benefit (reduction in probability of failure) of the two proposed

[44] The model was developed by Kiefner for the Northeast Gas Association (NGA). It has been used for at least 15 years by NGA member and nonmember gas pipeline companies for ranking relative risk of their natural gas pipelines for integrity management purposes. The relative risk scores are calculated considering the actual effects of various facility attributes as reflected in mechanistic relationships or the frequency of occurrence of incidents reported to PHMSA. The model is used to identify specific pipeline segments requiring focused risk mitigation and to evaluate the potential benefits of specific mitigations.

mitigation alternatives, namely hydrostatic testing of the existing line and reducing the maximum operating pressure, and 2) to compare the relative probability of failure scores of the existing pipeline and mitigation alternatives to the replacement of the existing 16-in pipeline with a new 36-in pipeline.

The risk model uses a very simplistic approach to model the beneficial effects of hydrostatic testing, in-line inspection, and pressure reductions. The model considers the beneficial effects of these mitigation methods as follows.

A hydrostatic test removes critically-sized, axially-oriented flaws, including external and internal corrosion defects, by causing them to fail. A hydrostatic test may also remove manufacturing defects that have not previously been exposed to the test pressure level. Pipelines may experience pressure-cycle induced fatigue crack growth of flaws under certain conditions. The rate of crack growth can be related to the magnitude and frequency of operating pressure cycles. Thus, the benefits of hydrostatically testing pipelines are to remove defects experiencing time-dependent growth (e.g., corrosion, fatigue) and removing manufacturing defects by exposing the pipeline to pressures above the operating pressure level, removing causing critically-sized defects.

The MFL inspection will reduce the likelihood of failure from external and internal corrosion. The model considers that the MFL inspection will locate these types of defects in the pipeline and that the operator will respond by excavating and examining certain indications appropriately. The model applies a 90% reduction to both the external and internal corrosion index scores in the year in which the ILI is performed. The value of this inspection erodes over time because corrosion is a time-dependent integrity threat.

Some segments in Line 1600 have been assessed with an in-line inspection in 2012, and thus the probability of failure index scores for internal and external corrosion already incorporates a mitigation factor. The beneficial effects of a hydrostatic test are not additive so the reduction from the hydrostatic test is smaller than it would be if the pipeline had not already been inspected by a recent ILI.

An alternative of replacing the existing Line 1600 with a new pipeline was considered in the model. The new pipeline alternative was assigned the following attributes:

- 36-in OD x 0.625-in WT, Grade X65 line pipe
- Fusion-bonded epoxy external coating
- 90% of the girth welds inspected by radiography to API 1104

- 100% cathodic protection within 12 months of installation
- Pre-service hydrostatic test to 90% of the SMYS of the pipe
- Depth of cover measured during construction along entire route

These characteristics resulted in a very low probability of failure score for the new pipeline alternative.

The risk model results are summarized in Figure 14. The color bands for each segment in the figure represent the probability of failure contribution for different threats.

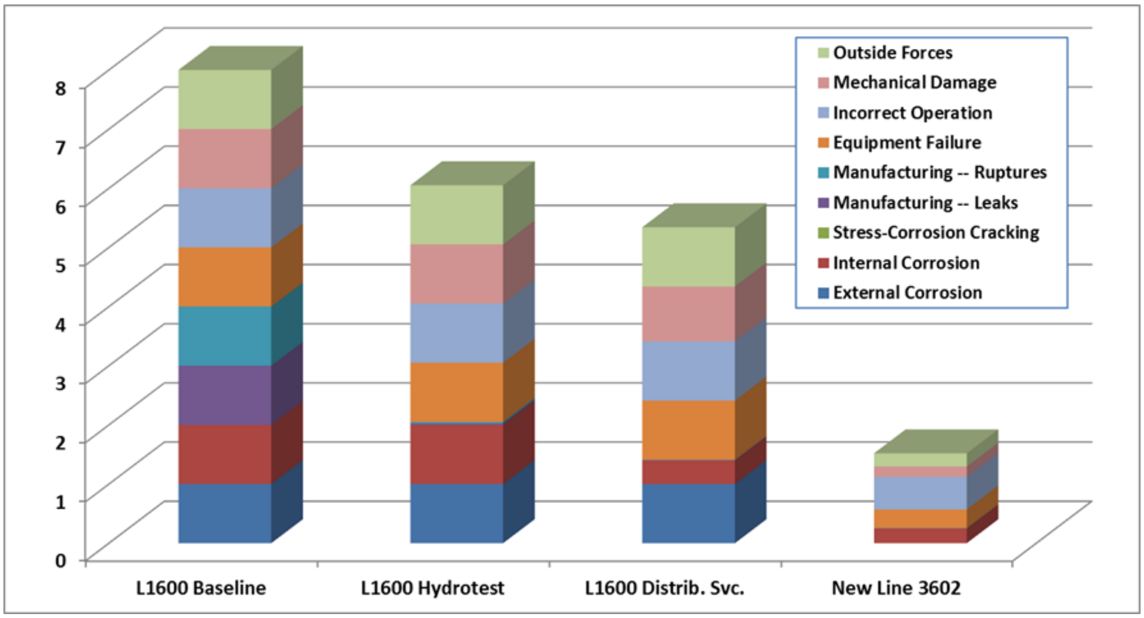

Figure 14. Summary of Probability of Failure Scores

The segment labeled "L1600 Baseline" represents the existing Line 1600 outside of steep slopes and fault crossing zones (which were not analyzed but certainly increase risk to the extent that the hazards are present). The columns labeled "L1600 Hydrotest" represents the POF scores after the line has passed a hydrostatic pressure test to an internal pressure of 1,200 psig. The column labeled "L1600 Distribution Service" represents the POF scores after Line 1600 has been derated to serve as a distribution line, with the MOP reduced from 800 psig to 320 psig. The column labeled "New Line 3602" represents the new 36-in diameter pipeline alternative.

As shown in the figure, both the hydrostatic pressure test and pressure reduction (to distribution service) alternatives reduce the POF scores somewhat. The pressure reduction alternative lowers the risk slightly more than the hydrostatic test scenario. The modest risk reduction with either alternative is due substantially to the fact that after mitigation it is still an older vintage pipeline with limited resistance to excavator damage or to natural event loadings, poor fracture control, and an incompletely characterized seam. It may not be possible to in-line inspect the pipeline at the lowered operating pressure, which will have an impact on the POF scores after the credit for the 2012 ILI expires. The POF levels represented by the new pipeline alternative are notably lower than the existing Line 1600 and both mitigation alternatives. Although the pipeline risk will gradually increase over time, the new materials, heavy wall thickness, coatings, and cathodic protection system will result in a much lower increase in POF over time than the existing Line 1600.

The results of the analysis above do not account for all details of construction and location with either Line 1600 or the proposed Line 3602. However, they are illustrative of the sensitivity of relative risk associated with the differing scenarios. It is noted that these results are consistent with the conclusions from the PWC cost-effectiveness study.[45]

Also, the model does not explicitly account for consequences. Conversion of Line 1600 to distribution service significantly lowers consequences in that the likelihood that a failure occurs as a rupture.

Summary

A review and analysis of risk factors and a risk assessment was performed to evaluate whether it makes sense from a public risk standpoint to pressure test the existing Line 1600, or derate it to distribution service without pressure testing it and build a new 36-inch transmission pipeline, Line 3602. The two options were compared in terms of inherent resistance or susceptibility to certain integrity threats based on typical characteristics and attributes of the two pipelines, historical performance trends affecting similar pipelines, and a relative risk model widely used in the natural gas industry.

The review of risk factors concluded that Line 1600 has greater vulnerability or susceptibility to several key failure mechanisms compared with the proposed Line 3602. Susceptibility to several of these factors is reduced in Line 1600 by lowering the operating pressure to distribution service with hoop stress levels below 20% of specified minimum yield strength (SMYS).

While there is no evidence that Line 1600 is unsafe, there is much that is unknowable about the line, including the ability of girth welds to withstand loadings from natural events, and features in the longitudinal seams. Risk is proportional to what is unknown, at least in part. The proposed Line 3602 will not have such gaps in relevant integrity data. After testing, Line 1600

[45] Price Waterhouse Cooper, "Cost-Effectiveness Analysis for the Pipeline Safety & Reliability Project", March 2016.

will still be an older vintage pipeline with limited resistance to many pipeline integrity concerns compared with the proposed Line 3602.