SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST SED-06)

Date Requested: October 6, 2017
Date Responded: October 17, 2017
Amended Response Submitted: October 20, 2017

This amended response replaces the response previously provided on October 17, 2017 in its entirety. The only change is that the attachment entitled *PSRP Application SED DR 06 Q1-Q2 L1600 and Related Facilities_Confidential.pdf* as submitted in response to this question on October 17, 2017 has been amended to identify a portion of Line 49-31 as "Distribution Function, but Operating at >20% SMYS At 400 PSIG MAOP." Please refer to the attachment entitled *PSRP Application SED DR 06 Q1-Q2 L1600 and Related Facilities_Confidential_Amended.pdf*. The confidentiality declaration provided on October 17, 2017 is applicable to this amended attachment.

QUESTION 1:

Please provide a detailed geographic map of Line 1600 with all regulators feeding local distribution systems identified by number from Rainbow to the southernmost end of Line 1600.

a. For each regulator responsive to this question, provide the regulator type and unique identification number.

b. For each identified regulator separately provide the last 3 years (2014, 2015, 2016) and 2017 YTD of annual gas volume draw off of line 1600 through each regulator feeding local distribution systems.

c. For each local distribution system identified in question 1, provide the number of services.

RESPONSE 1:

Some of the attachments to this response contain confidential materials provided pursuant to Cal. Pub. Util. Code § 583, G.O. 66-C/D, D.16-08-024 and the accompanying declaration.

Please see the attached revised and confidential map entitled *PSRP Application SED DR 06 Q1-Q2 L1600 and Related Facilities_Confidential_Amended.pdf*.

a. Please see the attached confidential file submitted along with this response (See document entitled *SED-06_Q1a_Attachment_Confidential.xlsx)*.

b. The identified regulator stations along Line 1600 serve to reduce pressure from Line 1600 to a desired pressure for distribution to end use customers. There are no metering devices installed at these regulator stations; therefore, the requested gas volumes for each regulator station cannot be directly attained.

As part of a diligent effort to identify ways that the requested data could be attained, SDG&E and SoCalGas (Applicants) considered other possibilities for how volumes might be determined.

One idea that was considered, but appears burdensome, is to attempt to identify the volumes of gas delivered to the approximately 150,000 customer meters served by Line 1600 and break it up by regulator station. This approach would entail identifying each individual account for the approximately 150,000 customer meters, obtaining the billing information, then researching and compiling the gas consumption for each of the past 45 months of their billing history. Consumption would then need to be converted from therms, back into standard cubic feet using the gas heating value per cubic foot for that given month.

Next, these 150,000 customers would need to be further evaluated to determine which regulator station provided gas service to them. For some of the regulator stations that are the only source of gas to a group of customers, a GIS extract could be performed to get a list of accounts associated with that regulator station. However, in many cases, this is not possible as the majority of customers along Line 1600 are served by a distribution system that is fed by multiple regulator stations. Thus, for most customers, it is not possible to determine a single regulator station feeding that customer. The engineering team may be able to use their judgment to manually assign customers to a regulator station, but this would not yield an exact representation.

Assuming that customers could be assigned to a regulator station, the next step in this process would be to aggregate the billing volumes for those groups of customers assigned to each regulator station to determine the volumes as requested.

This process is not an activity normally performed by Applicants and would require a special team consisting of subject matter experts from the billing group along with engineering and IT to complete the analysis described. The effort may be further complicated as the customer base is a mixture of residential, commercial and industrial customers where the bill calculation process is not uniform. The time and cost to determine volumes as requested using the above outlined process has not been assessed in detail but it could take weeks.

If the Safety and Enforcement Division (SED) deems the requested information as necessary to the purpose of its inquiry and worth the diversion of utility resources from other work, Applicants request an opportunity to discuss the scope of the request and the timing. In an attempt to provide SED with some information that may be useful, in the response to Question 1.C, below, Applicants include a Geographic Information System (GIS) extract of the number of meters associated with each regulator station (or grouping of regulator stations for multi-feed areas). It is hoped that this, along with the number of services and the map being provided in response to Question 1 provides SED with relevant information as to what each regulator station serves.

c. As explained in the response to Question 1.b above, some regulator stations serve as the single feed to an isolated distribution system while other distribution systems are fed by multiple regulator stations.

For those areas that are fed by a single regulator station, the number of services and the number of customer meters is provided in this response based on an extract from the gas GIS.

For the areas that are fed by multiple regulator stations, a more complex analysis had to be completed in order to provide a response since the boundaries of the area served by multiple regulators cannot be simply identified. Toward the southern half of Line 1600, to ensure adequate capacity and reliability, the distribution system in the more densely populated areas is constructed as an interconnected network of pipelines that are fed from multiple source pipelines. The analysis involved splitting up the interconnected distribution system and defining a boundary of the area served by regulators supplied primarily by Line 1600 versus being primarily supplied by regulators getting their source gas from another pipeline such as Line 1601, 3010, 2010 or other supply lines in the area.

To determine the boundary of the area primarily served by Line 1600 regulators, engineering judgment was used to set up a series of computer flow simulations to trace gas flow across the distribution system. The simulations were performed using traditional gas system planning criteria of a 1 in 35-year cold weather day. Based on engineering judgment, a conservative approach was used to set the boundary using the criteria that to be counted as being supplied by Line 1600, the trace of the gas had to show that at least 80% of the gas being supplied to the customer by the interconnected system originated in Line 1600.

This approach yielded 145,723 customer meters getting at least 80% of their gas from line 1600 on a 1 in 35-year cold weather day. Many more customers beyond this count receive some gas from Line 1600. However, for purposes of responding to this data request, if the simulation indicated that they received less than 80% from Line 1600, they were not included within the boundary of those supplied by Line 1600.

Once the boundary was defined for the areas supplied by multiple Line 1600 regulators, a GIS extract was completed to determine the number of services and customer meters within the given area. The results of this analysis are presented in the attached spreadsheet (entitled *SED-06_Q1c_Attachment_Confidential.pdf*).

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This amended response replaces the response previously provided on October 17, 2017 in its entirety. The only change is that the attachment entitled *PSRP Application SED DR 06 Q1-Q2 L1600 and Related Facilities_Confidential.pdf* as submitted in response to this question on October 17, 2017 has been amended to identify a portion of Line 49-31 as "Distribution Function, but Operating at >20% SMYS At 400 PSIG MAOP." Please refer to the attachment entitled *PSRP Application SED DR 06 Q1-Q2 L1600 and Related Facilities_Confidential_Amended.pdf*. The confidentiality declaration provided on October 17, 2017 is applicable to this amended attachment.

QUESTION 2:

Graphically depict all transmission lines (under the 20% SMYS operational definition listed in 49 CFR 192.3) that draw off of or feed Line 1600. Indicate direction of flow for each line responsive to this question.

RESPONSE 2:

Please see the revised and confidential map provided in response to Question 1 (entitled *PSRP Application SED DR 06 Q1-Q2 L1600 and Related Facilities_Confidential_Amended.pdf*). Arrows on the map indicating direction of flow are intended to show typical flow patterns. Actual flow patterns can vary over the course of the day depending on localized customer demand, especially gas demand swings caused by the dispatch of local gas fired electric generation, as well as overall demand across the service territory.

QUESTION 3:

Please provide the operating diagram for the facility called the "Rainbow Distribution Center." Please indicate the following on the diagram:

a. A symbol key for the operating diagram

b. The upstream custody transfer point

c. The upstream "system MAOP"

d. The upstream % SMYS at the "system MAOP"

e. The downstream "system MAOP" prior to derating

f. The downstream % SMYS at the "system MAOP" prior to derating

g. The downstream % SMYS at the "system MAOP" after derating

RESPONSE 3:

Attached is a schematic drawing (entitled *SED-06_Q3_Attachment_Confidential.pdf*) of the Rainbow Metering Station, which is located at the San Diego-Riverside County line separating the SDG&E service territory from the SoCalGas service territory, that identifies the SoCalGas upstream pipelines (1027, 1028, 6900) and the downstream SDG&E pipelines (3010 and 1600). A legend on the map has been provided and will act as a "symbol key" as requested. The "upstream customer transfer point" has been interpreted to mean the block valve designated as a distribution center per the definition of a transmission line in 49 CFR 192.3. The designated block valves are on the upstream SoCalGas-owned pipelines shortly before the gas is metered and flows into the downstream SDG&E-owned pipelines (1600 and 3010). "System MAOP" has been interpreted to mean the MAOP at which the pipeline is qualified to operate on the segment in proximity to the Rainbow Station and is downstream of a point of regulation. Within the continuous segment operating at the "System MAOP," there may be mixture of wall thicknesses, diameters and materials resulting in varying %SMYS values. As such, the %SMYS values depicted represent the highest %SMYS values being operated at the System MAOP denoted. Based upon SED's clarification, derating has been interpreted to mean the proposed de-rating of Line 1600 from a MAOP of 512 to 320 psig.

QUESTION 4:

Please describe in detail how the "system MAOP" of Line 1600 was established via 192.619 prior to derating.

RESPONSE 4:

The attachment provided with this response contains confidential materials provided pursuant to Cal. Pub. Util. Code § 583, G.O. 66-C/D, D.16-08-024 and the accompanying declaration.

The "system MAOP" of Line 1600 has been de-rated several times. Following the adoption of Federal Regulation (49 CFR Part 192) in the 1970s, pursuant to the "grandfather" provision in 49 CFR § 192.619(a)(3), it was determined that Line 1600 had an actual operating pressure of 812 psig during the five years before July 1, 1970. Thereafter, pipeline replacements along Line 1600 were designed to at least a design pressure under 49 CFR § 192.619(a)(1) that met 812 psig. (*See the confidential attachment to* SoCalGas/SDG&E's August 2, 2016 Amended Response to SED DR 3, Question 2) No later than December 21, 1978, the MAOP was reclassified as 800 psig as shown in the December 21,1978 SDG&E approved Transmission Map (See the confidential attachment entitled SED-06_Q4_Attachment_Transmission Mains-1978_Confidential.pdf). Following the PG&E San Bruno incident and during preparation of the Pipeline Safety Enhancement Plan in compliance with Public Utilities Code Sections 961 and 963, as a prudent operator and to establish a margin of safety factor equivalent to 1.25, the MAOP of Line 1600 was proactively reduced from 800 psig to 640 psig in 2011. Pursuant to a July 8, 2016 letter from the CPUC Executive Director to SDG&E, later embodied in Resolution SED-1, the maximum operating pressure (MOP) was further reduced to 512 psig on July 9, 2016 to further increase the margin of safety. Following clarification by SED of the intent of Resolution SED-1, the MAOP of Line 1600 was also reduced to 512 psig on September 10, 2017.

Date Requested: October 6, 2017
Date Responded: October 17, 2017

QUESTION 5:

For each "high pressure distribution main" fed off of Line 1600 do these mains feed downstream regulator stations, customers or both. Please provide a listing of each high-pressure distribution main, and what it feeds.

RESPONSE 5:

The attachment provided with this response contains confidential materials provided pursuant to Cal. Pub. Util. Code § 583, G.O. 66-C/D, D.16-08-024 and the accompanying declaration.

Please reference the attached file provided in response to this question (entitled *SED-06_Q5 and Q6_Attachment_Confidential.xlsx*). The information in the attached file is presented in order from north to south to aid in cross referencing against the map provided in response to Questions 1 and 2 of this data request.

Date Requested: October 6, 2017
Date Responded: October 17, 2017

QUESTION 6:

For each high-pressure distribution main, please include in the list from question 5, the “system MAOP” of this subsystem, and the % SMYS that the subsystem is operating at.

RESPONSE 6:

Please see the confidential file attached in response to Question 5. The requested information has been included in that file.

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(A.15-09-013)

(DATA REQUEST SED-06)

Date Requested: October 6, 2017
Date Responded: October 17, 2017
Amended Response Submitted: January 26, 2018

The response to Question 7 has been amended, the changes are noted in **red, bold and underline.** Deletions are in **bold and strikethrough.**

QUESTION 7:

Provide official financial records for the last 3 years (2014, 2015, 2016) and 2017 YTD of gas sales from SoCal Gas to SDG&E for the sale of gas from SoCal Gas to SDG&E at the Rainbow station.

RESPONSE 7:

No gas sales are made from SoCalGas to SDG&E at Rainbow. SoCalGas' Gas Acquisition Department is responsible for the purchase of gas sold to core customers on the SDG&E system pursuant to Commission D.07-12-019 and as reflected in SoCalGas CPUC Tariff Sheet 52769-G, Preliminary Statement - Part V - Balancing Accounts Purchased Gas Account (PGA). Noncore customers and their suppliers including SDG&E's Electric Fuel Procurement Department are responsible for the purchase of gas delivered to noncore customers. Both Gas Acquisition and noncore suppliers pay the Backbone Transportation Service rate for gas scheduled to be delivered into the SoCalGas and SDG&E systems.

Pursuant to **~~the System Integration Proposal authorized per~~** Commission **~~D.06-04-033~~** **D.07-12-019**, SoCalGas, as the System Operator, manages the supply of gas across both systems until transferred to the SDG&E distribution system. Gas supplies move from upstream SoCalGas-owned pipelines into downstream SDG&E-owned pipelines (1600 and 3010) at Rainbow Metering Station.

SoCalGas does charge SDG&E for local transmission service measured from gas meters located at Rainbow, Moreno, San Onofre and Otay Mesa. The cost components recovered in SDG&E's wholesale transportation rate (GT-8CA) are as follows: customer-related costs (meter, regulator, billing, etc.); storage services; unaccounted for gas; regulatory account balances (System Reliability Memorandum Account (SRMA), Self-Generation Program Memorandum Account, etc.). Storage costs comprise the largest of these cost components.

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PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST SED-06)

Additional Question Per December 20, 2017 ALJ Ruling

Date Requested: December 20, 2017
Date Responded: December 29, 2017

The December 20, 2017 Administrative Law Judge's Ruling Setting Aside Submission and Reopening The Record To Enter Safety And Enforcement Division (SED) Advisory Opinion and San Diego Gas & Electric Company and Southern California Gas Company Response To SED Data Request Into The Record and To Take Supplemental Testimony (ALJ Ruling) directed Applicants to respond to an additional question (Question 8) as part of circulating their prior response to SED Data Request 06. Applicants do so below.

QUESTION 8:

At a high level, what cost impacts would a change in SDG&E's and SoCalGas' definition of "distribution center" have across the SDG&E/SoCalGas systems, depending on the nature of the change?

RESPONSE 8:

Applicants object that the question is vague, ambiguous and calls for speculation because it does not identify the "nature of the change" to the definition of the phrase "distribution center." In the absence of further guidance, Applicants interpret the ALJ Ruling as referring to SED's December 15, 2017 Analysis and Opinion on Supplemental Question A (SED Advisory Opinion)—specifically, the discussion of whether Line 1600 would be a transmission line or distribution line if it were operated at a hoop stress of less than 20% of its Specified Minimum Yield Strength (SMYS)—and requiring SDG&E and SoCalGas to extrapolate from this discussion of Line 1600 in the SED Advisory Opinion and apply a similar interpretation across the entire integrated SDG&E/SoCalGas transmission system. Applicants further object that the SED Advisory Opinion itself is also vague, ambiguous and calls for speculation because it does not provide a clear or consistent definition of "distribution center" that can be applied across SDG&E and SoCalGas' integrated gas transmission system. Notwithstanding and without waiving the foregoing objections, Applicants respond as follows:

Applicants are uncertain how SED determines what a "distribution center" is or where one is located. While the SED Advisory Opinion expressly acknowledges that "[o]ne must also look at where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale," the SED Advisory Opinion does not apply this standard to Line 1600. Gas entering Line 1600 (as well as Line 3010) is primarily delivered to customers who purchase it for consumption and not resale. Thus, if this standard were applied to Line 1600, Line 1600 would be considered downstream of a distribution center.

The SED Advisory Opinion nevertheless concludes Line 1600 is upstream of a distribution center and asserts that “Line 1600 receives gas upstream from a SoCal Gas transmission pipeline. Thus gas does not enter the system at Rainbow; it is essentially an extension of the upstream transmission line route whose primary function is to supply gas to the 63 regulator stations.” Because gas *does* enter SDG&E’s system at Rainbow Metering Station, it is unclear how the SED Advisory Opinion arrived at this determination. The SED Advisory Opinion analysis seems to focus on the fact that the SoCalGas and SDG&E gas transmission system operates as a single integrated system. If that is the case, then the “distribution centers” for the integrated system would be located where gas is delivered into the single integrated system, *i.e.*, from an intrastate, interstate, or international pipeline, a California producer or a gas storage field. That is also consistent with the SED Advisory Opinion’s reference to the PHMSA Glossary’s definition of “distribution center” as a “location at which gas may change ownership from one party to another.” Under either case, Line 1600 remains downstream of a distribution center and, when operated at a hoop stress less than 20% of SMYS, would not be a transmission line under 49 of the Code of Federal Regulation (CFR) Part 192.3.

The SED Advisory Opinion further concludes that Line 1600 would remain a transmission line under 49 CFR § 192.3, even if operated at a hoop stress less than 20% of its SMYS. While the basis for this conclusion is not entirely clear, the analysis appears to focus on the fact that Line 1600 serves 63 regulator stations downstream of Rainbow Metering Station. The Advisory Opinion states: “Each of the 63 regulator stations can be considered a distribution center; downstream of the 63 regulator stations, gas enters the distribution systems to the customers who purchase it for consumption.” The conclusion that Line 1600 would remain a transmission line if operated below 20% SMYS is inconsistent with this assertion, however, because the gas identified as entering piping delivered for customer consumption at the 63 regulator stations is the same gas that flows through Line 1600.

For purposes of preparing a response to this request for a high level estimate of the potential cost impact of reclassifying distribution pipelines under a different definition of “distribution center,” Applicants assume SED’s definition of the phrase “distribution center” to be the location at which gas passes through a regulator station reducing its pressure to 60 psig, which is the pressure at which it is delivered into the distribution mains and services serving customers. If this hypothetical definition of “distribution center were applied to the integrated SoCalGas/SDG&E natural gas distribution system,” approximately 3,500 miles of pipelines operated at hoop stress levels less than 20% of SMYS would be reclassified as transmission pipelines.

Additional Question Per December 20, 2017 ALJ Ruling

Date Requested: December 20, 2017
Date Responded: December 29, 2017

Preparation of a detailed estimate of the potential cost impact of such a reclassification would require SDG&E and SoCalGas to conduct pipeline surveys and perform detailed records reviews for the approximately 3,500 miles of pipeline that would potentially be affected by the above change in definition. Indeed, preliminary high level cost estimates prepared during a two-month timeframe for the first phase of PSEP were determined by the Commission to be "rudimentary at best" and "not sufficient to justify this Commission to authorize for ratemaking purposes." (D.14-06-007 at 26.) Accordingly, these cost estimates, prepared in about one week, are even more high level and rudimentary and should not be considered sufficient for purposes of adopting a broad change in policy that could have systemwide ratemaking impacts. Moreover, as a matter of public policy, a decision by the Commission to implement a sweeping change to how pipelines are classified as transmission or distribution in California should only be reached through a rulemaking process that includes all California pipeline operators, following a detailed assessment of potential safety, system and cost impacts. SDG&E and SoCalGas raised this concern to the Commission more than three years ago and specifically requested that "this matter of statewide importance affecting the operation of the State's natural gas pipeline system be addressed in the Commission's Pipeline Safety Rulemaking to address this issue thoughtfully and on a statewide basis" in motions filed on July 21, 2014 in both A.13-12-012 (PG&E's 2015 Gas Transmission and Storage Services Application) and in R.11-02-019 (the Pipeline Safety Rulemaking). In those motions, SDG&E and SoCalGas explained:

> [D]iffering definitions of "distribution center" result in different classifications of pipeline assets, which, if applied consistently across the State, would have direct safety, operational and ratemaking impacts on all California natural gas pipeline operators and their customers. As such, it would not be appropriate for the Commission to address this matter of statewide importance in an isolated utility-specific application proceeding

Neither motion was addressed through a formal published ruling or decision, and SDG&E and SoCalGas reiterate here that a change in the State's definition of distribution center would have direct safety, operational and ratemaking impacts on all California natural gas pipeline operators and their customers and that those impacts should all be thoughtfully considered on a statewide basis.

This preliminary high level estimate of the potential cost impacts of redefining the term "distribution center" is based on the following assumptions:

(1) All of the approximately 3,500 miles of SDG&E and SoCalGas pipelines currently classified as high pressure distribution lines (*i.e.*, operating at hoop stress levels below

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20% of SMYS but above 60 psig), would be classified as transmission lines under 49 CFR section 192.3 and Public Utilities (PUC) section 955, *et seq*.

(2) The re-classified pipelines will be subject to 49 CFR Part 192 “Subpart O – Gas Transmission Pipeline Integrity Management” and would require an assessment every seven years using In-Line-Inspection (ILI), Direct Assessment (DA) or Pressure Testing based on the threats to be addressed. Since most of these pipelines are smaller diameter, have multiple diameter changes, and operate at a lower operating pressure, ILI is unlikely to be a viable option, so most of these pipelines would be assessed using DA or Pressure Testing every seven years. Applicants’ understanding is that, roughly, pressure must be at approximately 400 psig to utilize conventional ILI devices (pigs). While robotic or tether pigs exist, and can be used in some situations, the cost is significantly higher than conventional ILI since access points must be provided every 2,000 to 4,000 feet per each run. Unlike conventional ILI, where the assessment tool (the pig) is inserted and pushed by a differential of gas pressure on either side of the pig, a tethered pig must be tied (tethered) and mechanically pulled through the cased main. A robotic tool requires access points for entry, to re-charge and to exit to be installed in the pipeline for each run. The cost and effort to set up this form of ILI inspection is more than a typical ILI assessment, as the pipeline may need to be taken out of service and numerous access points must be installed in the pipeline due to the length of the tether and limitations on the number and types of bends the tether/robot can accommodate. This is generally not considered feasible, because the cost of a tethered/robotic pig assessment can be as much as three to five times greater per inspection than a typical ILI assessment, and is even greater on a per foot-of-pipeline-inspected basis.

   a. Subject Matter Experts (SMEs) estimate that 50% of the reclassified pipelines would lie within High Consequence Areas (HCAs) and would require an assessment of 1,750 miles. These high pressure pipelines are located closer to delivery points. Currently about 36% of transmission pipeline miles in the SoCalGas/SDG&E transmission system are within HCAs, but include pipelines that originate at the Utilities’ territory borders and travel through rural areas. Therefore, 50% seems to be a reasonable estimate for pipelines located in urban areas. It should be noted that HCAs can be determined based on two methods, which can add variability to this estimate: one which is dependent on the Potential Impact Radius (Method 1) and the other which is primarily driven by the Class Location (Method 2). To complete this analysis, the buildings located within and near the corridors of these pipelines would need to be reviewed and HCA calculations completed to provide a higher degree of accuracy.

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b. The miles requiring an assessment is split between DA and replacement, with 30% (about 525 miles) requiring replacement due to the inability to perform a DA due to identification of threats on the pipelines or coating conditions. As previously noted, since these pipelines operate at a low pressure and have multiple diameters, ILI is not a viable option. Nor is pressure testing, due to the difficulty and costs associated with managing customer impacts.
c. Once a pipeline is replaced, subsequent assessment can be done using DA. Therefore, the costs to replace are viewed as a one-time expense and DA is viewed as an on-going expense for the entire population of estimated HCA miles.

(3) The reclassified pipelines will be subject to PUC sections 957 and 958. The reclassified pipelines will primarily be replaced rather than pressure tested because of anticipated high customer impacts that would be difficult to manage at reasonable cost due to the number of Regulator Stations and customers served directly from the high pressure pipelines (similar to Line 1600). In addition, the pipelines that are not piggable and installed prior to 1946 are identified for replacement under the Commission-approved PSEP Decision Tree, since pressure testing is less effective at addressing historic welding and construction practices (i.e. oxy-acetylene welds/wrinkle bends). For compliance with PUC section 957, since section 192.181 (Distribution Line Valves) is not prescriptive regarding the number of valves required, the assumption is that a valve installation will be required every eight miles for compliance with section 192.179 (Transmission Line Valves) for transmission pipelines in Class 3 areas.
a. It is estimated that 24% (about 840 miles) of the newly reclassified as transmission miles would fall within the PUC section 958. This estimate is based on the initial percentage identified in Applicants' PSEP in 2011.
b. This mileage is split between pressure testing and replacement. Generally, under the PSEP Decision Tree process, the smaller diameter transmission pipelines operated by Distribution have been 83% replaced and 17% pressure tested. Applying this allocation to the distribution pipelines that would be re-classified as transmission under the SED's definition of "distribution center," would result in replacement of about 697 miles and pressure testing of about 143 miles of pipeline. Given the high rate of replacement, it is assumed that this mileage would be inclusive of the pre-1946 pipelines that are non-piggable; therefore, no additional mileage is added to address this subset of replacements.
c. It should be noted that the drivers for replacing pipe are different for Subpart O and PUC section 958; therefore, no overlap can be determined for purposes of the estimate provided in this response.

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Additional Question Per December 20, 2017 ALJ Ruling

Date Requested: December 20, 2017
Date Responded: December 29, 2017

The attachment to this response provides Applicants' estimate of what a change in the Applicants' definition of "distribution center" may cost. For illustrative purposes, Applicants present the high level cost estimates on a loaded basis, applying a high level estimate of what the applicable loaders may actually be. Actual loaders would be applied based on the nature of any change to the distribution and transmission systems and the timing of when the activities occur. All costs require escalation to account for the duration of time anticipated to implement a significant change across the system, which could span several years and even decades. The cost estimates may be further impacted significantly by various factors including, but not limited to, whether a pipeline is in a rural, urban, or highly urban area, pipeline length, pipeline diameter, the number of automatic/remote controlled valves that may be required to be installed, whether it is within an existing right-of-way, and whether the existing right-of-way can accommodate installation of a new pipeline in parallel to the existing pipeline. No project-specific land acquisition costs have been included in this high level estimate. In addition to the costs identified in the attachment, reclassified pipelines may also require additional operating and maintenance activities under 49 CFR section 192, including but not limited to, increased leak survey, pipeline patrol and repair activities.

Any change to the treatment of the Applicants' infrastructure will result in rate impacts. Question 8 does not request an estimate of potential rate impacts, and Applicants do not provide an estimate of potential rate impacts in this response. Before implementing a change in how infrastructure is classified in California, the Commission should carefully consider customer rate impacts and evaluate potential changes in customer class-specific and intrastate transportation revenues and rates.