Application No: A.15-09-013
Exhibit No.: __________
Witness: D. Schneider

In The Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for a Certificate of Public Convenience and Necessity for the Pipeline Safety & Reliability Project	Application 15-09-013 (Filed September 30, 2015)

PREPARED DIRECT TESTIMONY OF

DOUGLAS M. SCHNEIDER

ON BEHALF OF

SAN DIEGO GAS & ELECTRIC COMPANY

AND

SOUTHERN CALIFORNIA GAS COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

March 21, 2016

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I. PURPOSE AND OVERVIEW

The purpose of my prepared direct testimony on behalf of San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) (collectively, the Utilities) is to explain why, from a policy standpoint, the Utilities' Pipeline Safety & Reliability Project (PSRP) should be approved by the California Public Utilities Commission (CPUC or Commission). The PSRP (or Proposed Project)[1] consists of de-rating the existing Line 1600 and replacing its transmission function with a new approximately 47-mile, 36-inch diameter natural gas transmission pipeline (Line 3602) and associated facilities between the Rainbow Metering Station (Rainbow Station) and a tie-in point with Line 2010 on Marine Corps Air Station (MCAS) Miramar. The Proposed Project presents a timely and rare opportunity to cost-effectively achieve three fundamental objectives for the integrated SoCalGas and SDG&E natural gas transmission system (Gas System) for the portion that operates within San Diego County (SDG&E system) in the following manner:

1. <u>Enhance the Safety of Existing Line 1600 and Modernize the System with State-of-the-Art Materials</u>: The Proposed Project enables the Utilities to enhance the safety of their integrated natural gas transmission system and comply with California Public Utilities Code (PUC) Section 958 and Commission Decision (D.) 11-06-017 by de-rating the maximum allowable operating pressure (MAOP) of Line 1600, a pipeline that was constructed in 1949 from Rainbow Station to the tie-in point with Line 2010 using pipe primarily seam welded using the electric flash weld process by A.O. Smith Corporation. Following the pipeline rupture in San Bruno in 2010, the Utilities proactively reduced the MAOP on Line 1600 in order to increase the margin of safety on the pipeline. The Utilities subsequently conducted an in-line inspection (ILI) of the pipeline in order to validate the integrity and safety of the pipeline. The results of that in-line inspection, along with knowledge of the manufacturing methods and overall operating history of the line, lead to the conclusion that the long-term safety of Line 1600 would be better addressed through de-rating of the line, rather than through a pressure test[2] and continued operation at transmission pressure. To replace the transmission function of this legacy pipeline, the Utilities propose installation of Line 3602, a new state-of-the-art gas

[1] The Utilities use these terms interchangeably throughout the testimony and Amended Application.
[2] The Utilities use the terms "pressure test" and "hydrotest" interchangeably throughout the testimony and Amended Application.

transmission pipeline. Construction of a new line would enable the Utilities to reduce the operating pressure of Line 1600 to a distribution level of service, significantly enhancing the overall safety and integrity of the system; continue to serve customers directly fed off Line 1600; avoid the potential customer impacts associated with pressure testing this portion of Line 1600; and enhance system reliability, resiliency, and operational flexibility.

2. Improve System Reliability and Resiliency[3] by Minimizing Dependence on a Single Pipeline: San Diego County is essentially completely reliant on the compressor station in the City of Moreno Valley (Moreno Compressor Station) and Line 3010, which together provide approximately 90 percent of SDG&E's capacity. As a result, an outage on Line 3010 or at the Moreno Compressor Station would constrain available capacity in San Diego, which may lead to gas curtailments. This situation would be alleviated with the new 36-inch diameter line providing resiliency for both Line 3010 and the Moreno Compressor Station. The Proposed Project proposes installation of Line 3602, a 36-inch diameter line, to replace Line 1600's transmission function and enable core and noncore customers to continue to receive gas service in San Diego in the event of a planned or unplanned service reduction or outage of the existing 30-inch diameter Line 3010 or the Moreno Compressor Station.

3. Enhance Operational Flexibility to Manage Stress Conditions by Increasing System Capacity: Because the proposed Line 3602 would be 36 inches, the Proposed Project would increase the transmission capacity of the Gas System in San Diego County by approximately 200 million cubic feet per day (MMcfd). This increase in transmission capacity will allow the Utilities to reliably manage fluctuating peak demand of core and noncore customers, including electric generation (EG) and clean transportation. More generally, a 36-inch Line 3602 would provide incremental pipeline capacity that would provide flexibility to operate the system by expanding the options available to handle stress conditions on a daily and hourly basis that place customer service at risk.

In addition to accomplishing these fundamental objectives, the Proposed Project also enables environmental benefits, considers how best to enable system piggability, and furthers efforts to complete the Pipeline Safety Enhancement Plan (PSEP) work "as soon as practicable."[4]

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[3] The term "resilience" means the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents. Press Release (dated Feb. 12, 2013) Presidential Policy Directive -- Critical Infrastructure Security and Resilience, *available at* https://www.whitehouse.gov/the-press-office/2013/02/12/presidential-policy-directive-critical-infrastructure-security-and-resil. The Utilities use the term "resiliency" and "redundancy" interchangeably throughout the testimony because a redundant transmission pipeline enables a gas system to be resilient.

[4] *See* D.11-06-017, at 19-20.

In assessing the reasonableness of the Proposed Project, the Utilities considered numerous alternative projects, and engaged in an analysis of the costs and benefits of the Proposed Project and the alternatives. Based on this analysis, the Utilities have concluded that the Proposed Project is the most reasonable and prudent means to comply with PUC Section 958 and D.11-06-017; and enhance system safety, reliability, resiliency, and operational flexibility. As such, as explained in greater detail below, the Proposed Project should be approved expeditiously to realize the above benefits and accomplish the shared objective of prudently enhancing the safety and reliability of the Utilities' natural gas transmission system.

II. DESCRIPTION OF SDG&E'S SERVICE TERRITORY AND THE UTILITIES' INTEGRATED GAS SYSTEM

SDG&E's service territory for natural gas is the County of San Diego.[5] The county has a growing population of 3,211,252,[6] and as a county, has a larger population than 21 states and the District of Columbia. San Diego is also home to the largest concentration of military in the world and the largest federal military workforce in the United States. SDG&E safely and reliably provides natural gas service to its residential, commercial, and EG customers, including the military, hospitals, and schools through over 860,000 natural gas meters and provides electric service to 3.4 million customers through 1.4 million electric meters in San Diego and southern Orange Counties.

Natural gas is a foundational fuel for California, including San Diego, serving residential, EG, and business customers. California consistently ranks as the second highest gas-consuming state in the nation, which indicates that natural gas is an integral part of the State's electricity and

[5] SDG&E Gas Tariff Book, Sheet 1, CPUC Sheet No. 7072-G.
[6] U.S. Census 2013 estimate.

fuel portfolio.[7] Customers rely on natural gas deliveries to heat homes and businesses, heat water, and cook food. Natural gas powers buses, trucks, and cars to provide low-emission alternatives to traditional petroleum vehicles. Electric generators and electric grid operators historically had options to meet electric demand with less reliance on natural gas. Due to changes in the California energy and environmental landscape, however, as explained below, reliance on natural gas supplies has increased dramatically.

Pursuant to D.06-04-033, the Utilities operate the Gas System as an integrated system, which is described in the Prepared Direct Testimony of David Bisi.[8] As explained by Mr. Bisi, the Utilities primarily rely on three major components of the SDG&E system to deliver gas from north to south into San Diego County: (1) Line 1600, (2) Line 3010, and (3) Moreno Compressor Station.

Line 1600 is a 16-inch natural gas transmission pipeline that provides approximately 10 percent of SDG&E's capacity (assuming compression is available). Line 1600 was installed in 1949, twelve years before the Commission first adopted pressure testing regulations.[9] As such, as explained below, pursuant to PUC Section 958 and D.11-06-017,[10] Line 1600 must be

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[7] California Energy Commission (CEC), Assembly Bill (AB) 1257 Natural Gas Act Report: Strategies to Maximize the Benefits Obtained From Natural Gas as an Energy Resource, November 2015 (AB 1257 Report), at ii.

[8] The benefits of an integrated system "include diversity and reliability of supply, and gas-on-gas competition." *See* D.06-04-033, at 46.

[9] *See* D.11-06-017, at 5 n.3 ("Pipeline with MAOP set via subsection 619(c) is often referred to as "grandfathered" pipeline because it is exempted from MAOP federal regulations adopted after 1970, which required all new transmission pipelines to be pressure tested, prior to being placed in service. The Commission's General Order 112, which became effective on July 1, 1961, mandated pressure test requirements for new transmission pipelines (operating at 20% or more of SMYS) installed in California after the effective date.").

[10] The California Natural Gas Pipeline Safety Act of 2011 added safety regulations for intrastate pipelines, including Section 958 of the PUC, which requires all natural gas intrastate transmission line segments that were not pressure tested or that lack sufficient documentation of a pressure test to be pressure tested or replaced.

pressure tested, replaced, or removed from transmission service to comply with State law and D.11-06-017.[11]

Line 3010 is a 30-inch transmission pipeline that provides approximately 90 percent of SDG&E's capacity (assuming compression is available). The line was placed into service in 1961 and has also been inspected using ILI devices. In addition, this pipeline was pressure tested after construction.

Moreno Compressor Station boosts pressure for essentially all gas supplies that come into San Diego County from the north through Line 3010 and Line 1600.

III. THE UTILITIES' PIPELINE SAFETY ENHANCEMENT PLAN

On September 9, 2010, a 30-inch diameter natural gas transmission pipeline owned and operated by Pacific Gas and Electric Company ruptured and caught fire in the city of San Bruno, California. In response, on February 24, 2011, the Commission issued Rulemaking (R.) 11-02-019, "a forward-looking effort to establish a new model of natural gas pipeline safety regulation applicable to all California pipelines."[12]

In that Rulemaking, on June 9, 2011, the Commission declared that "all natural gas transmission pipelines in service in California must be brought into compliance with modern standards of safety. Historic exemptions must come to an end with an orderly and cost-conscience implementation plan."[13] To accomplish this sweeping regulatory change, the Commission directed all California natural gas pipeline operators to file and serve "a proposed Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan

[11] Under the Proposed Project, the transmission function of Line 1600 would be replaced by the new line (Line 3602). Installation of the Proposed Project would enable the Utilities to comply with Section 958 and D.11-06-017 by converting existing Line 1600 to distribution service.
[12] R.11-02-019, at 1.
[13] D.11-06-017, at 18.

(Implementation Plan) to comply with the requirement that all in-service natural gas transmission pipeline in California has been pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619 (c)."[14]

In 2011, the Utilities filed their proposed Implementation Plan or Pipeline Safety and Enhancement Plan (PSEP), which set forth their plan to test or replace transmission pipelines that did not have documentation of a pressure test to at least 1.25 times the maximum allowable operating pressure (MAOP) in order to achieve the Commission's safety objectives. Consistent with the Utilities' commitment to public safety, and the Commission's directives in D.11-06-017, the PSEP identifies pipeline segments in populated and High Consequence Areas (HCAs) that require additional documentation of pressure testing to satisfy the Commission's requirements set forth in D.11-06-017 and PUC Section 958, and proposes a plan to pressure test or replace all such segments. PSEP prioritizes pipeline segments in more populated areas ahead of pipeline segments in less populated areas and utilizes the concepts in a "Decision Tree" to select replacement or pressure testing of the pipeline.

The PSEP Decision Tree provided below was approved by the Commission in D.14-06-007, and represents the Utilities' analytical approach to testing or replacing pipelines to enhance the safety of the SDG&E and SoCalGas transmission system.[15] In approving the PSEP Decision Tree, the Commission explained, "by adopting the analytical approach in the Decision Tree we address all pipelines to ensure the system as a whole can be relied upon to be safe, not just complying with the safety rules of a bygone era."[16] Specifically, the Commission adopted: "the

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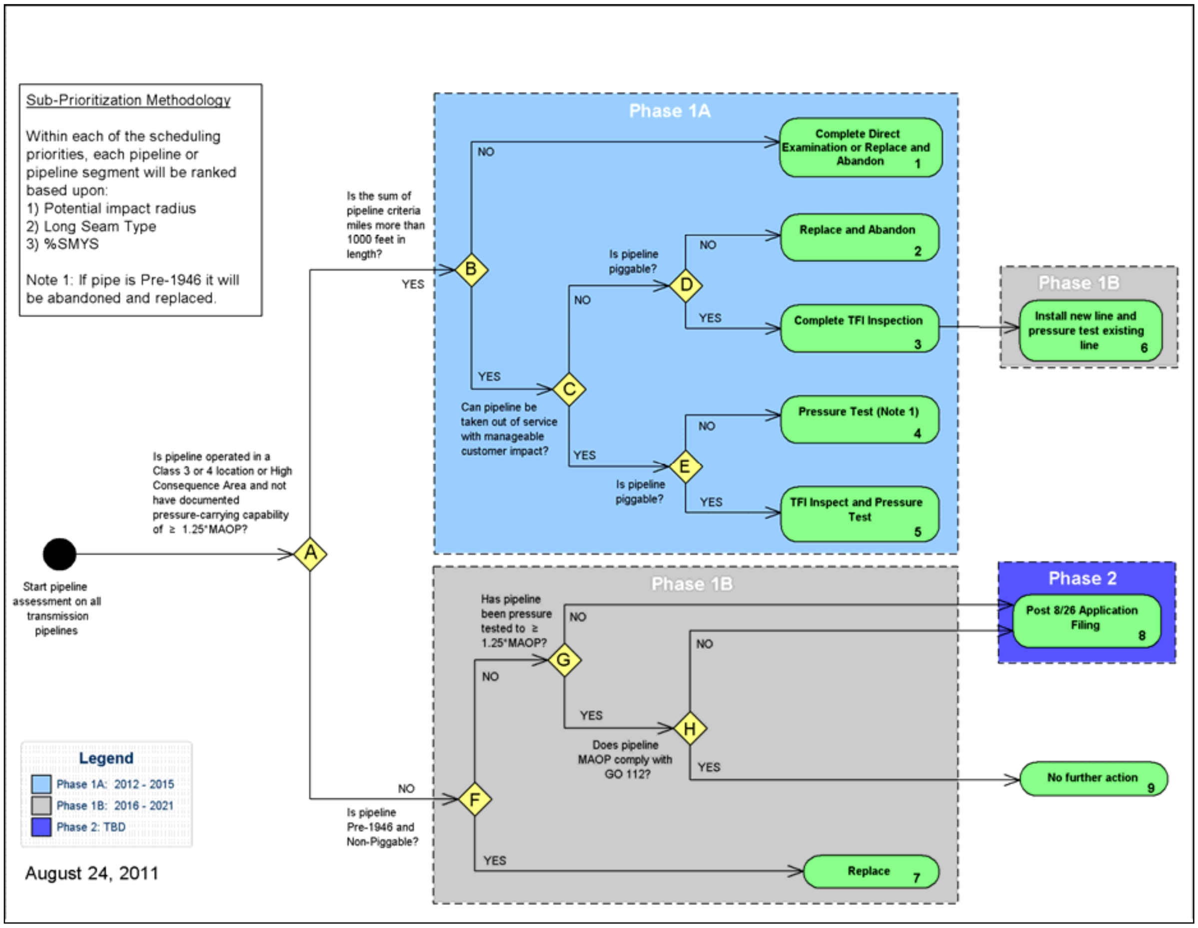
[14] D.11-06-017, at 31, Ordering Paragraph (OP) 3.
[15] *See* D.14-06-007, at 24.
[16] *Id.* at 22-23.

concepts embodied in the Decision Tree,"[17] "the intended scope of work as summarized by the Decision Tree,"[18] and "the Phase 1 analytical approach for Safety Enhancement…as embodied in the Decision Tree…and related descriptive testimony."[19]

FIGURE 1
PSEP DECISION TREE



Under the Utilities' approved Decision Tree in Figure 1 above, all PSEP pipelines in populated and HCAs are prioritized for further action and placed within one of three categories: (1) pipeline segments that are 1,000 feet or less in length;[20] (2) pipeline segments greater than

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[17] *Id.* at 1.
[18] *Id.* at 22.
[19] *Id.* at 59, OP 1.
[20] Although the Decision Tree approved in D.14-06-007 and included as Attachment 1 to the decision indicates in Box 1 that segments of less than 1,000 feet may be addressed through Direct Examination or

1,000 feet in length that can be removed from service for pressure testing with manageable customer impacts;[21] and (3) pipeline segments greater than 1,000 feet in length that cannot be removed from service for pressure testing with manageable customer impacts.[22] Additionally, the Utilities' clarified that, as prudent operators, they would also "consider cost and engineering factors for the improvement of the pipeline asset"[23] and may identify situations in which spending incremental dollars to replace a pipe segment today will avoid the need to request additional funds in a future regulatory proceeding to make a line piggable, add capacity, or replace sections of a pipeline that qualifies for replacement due to leakage history. For example, the Utilities may identify situations where the installation of a new pipeline may improve the overall safety of the system and quality of life of the pipeline asset because the newer pipe can have structural advantages compared to earlier vintage lines.[24]

The Utilities' testimony in support of PSEP described Line 1600 as being in the third category because it was identified as not being able to be removed from service for pressure testing with manageable customer impacts.[25] Under the Decision Tree, Line 1600 was therefore identified as being included within Box 6 (Phase 1B), which specifies "Install new line and

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replacement and abandonment, Public Utilities Code Section 958 precludes the Utilities from addressing these segments using Direct Examination.

[21] "Manageable customer impacts" means that the Utilities: (1) will not interrupt service to its core customers in order to pressure test a pipeline; (2) will work with noncore customers to determine if an extended outage is possible; (3) will, where necessary, interrupt noncore customers for short periods of time as provided for in their tariffs; and (4) will – as is their current practice – work with noncore customers to plan, where possible, service interruptions during scheduled maintenance, down time, or off peak seasons. A.11-11-002, Exh. SCG-20, Phillips Rebuttal Testimony, at 3. The criteria used to determine whether a segment can be taken out of service varies based upon specific pipeline and local system characteristics that may include, but are not limited to, system looping and flexibility; impact to capacity; curtailment to noncore customers; impact to shippers, customers, and the gas market; availability of alternate sources of gas; anticipated outage duration; and the ability to mitigate these negative impacts through construction of parallel systems.

[22] D.14-06-007, Attachment 1.

[23] A.11-11-002, Exh. SCG-20, R. Phillips Rebuttal Testimony, at 8-9.

[24] *Id.* at 10.

[25] A.11-11-002, Exh. SCG-04, D. Schneider Amended Direct Testimony, at 51.

pressure test existing line." Because the Utilities identified Line 1600 as a pipeline that could not be addressed in the near term due to the need to construct new infrastructure to maintaining service during pressure testing, the Utilities sought authorization to recover the costs of engineering and designing a replacement pipeline and to conduct a detailed in-line inspection of Line 1600.[26] As the knowledgeable operators of the Gas System, in assessing these other cost and engineering factors, the Utilities determined the Proposed Project offers the best approach to compliance with State test or replace requirements, further enhances safety beyond minimal compliance by "[o]btaining the greatest amount of safety value, i.e., reducing safety risk,"[27] provides beneficial system reliability/resiliency, and enhances operational flexibility. As a result, the Utilities filed the original Application seeking approval of the Proposed Project.

IV. Line 1600 is Legacy Pipe with Known Manufacturing Flaws

Line 1600 was manufactured by A.O. Smith Corporation using the electric flash weld process. A.O. Smith flash welded pipe is identified by the Pipeline and Hazardous Materials Safety Administration (PHMSA) as "legacy pipe."[28] The non-state-of-the-art flash welding manufacturing process is associated with a number of seam-related anomalies, including cracks referred to as "hook cracks." While these cracks can be proven to be stable at the time of a pressure test, this manufacturing process has higher safety risks compared with other manufacturing processes due to the risk of an interactive threat with corrosion, as explained further in the Prepared Direct Testimony of Travis Sera. Line 1600 contains the largest mileage

[26] A.11-11-002, Exh. SCG-22, D. Bisi Rebuttal Testimony, at 5-8.
[27] A.11-11-002, Exh. SCG-20, R. Phillips Rebuttal Testimony, at 2.
[28] PHMSA defined a legacy pipe as part of its Proposed Gas Transmission Integrity Verification Process, a multi-disciplinary engineering effort to verify that steel gas transmission pipeline integrity is adequate for continued operation for some desired future period. There, PHMSA found that a legacy pipe means low-frequency electric resistance weld (LFERW), spiral submerged arc welding (SSAW), flash weld (A.O. Smith), or pipe with a joint factor less than 1 (*e.g.*, lap welded pipe).

of A.O. Smith pipe operating in the Gas System at a transmission service level, and is located in high consequence areas.

The Utilities do not have documentation to demonstrate Line 1600 was pressure tested when placed in service in 1949. Rather, Line 1600 was "grandfathered" under federal pressure testing regulations adopted in 1970.[29] As such, Line 1600 is also required to be pressure tested, replaced, or removed from transmission service to comply with PUC Section 958 and D.11-06-017.

As an interim measure to validate the safety of the pipeline, consistent with the approach described in the approved PSEP, the Utilities performed ILI of Line 1600 using both axial and transverse (circumferential) magnetic flux leakage technology. The Utilities completed ILI of approximately 49 miles of Line 1600 (99 percent of Line 1600) with axial and circumferential ILI tools in 2012 - 2014.[30] The ILI data resulted in over 50 excavations to verify the integrity of the pipeline and confirmed that Line 1600 does indeed have numerous hook cracks and other manufacturing anomalies. Assessment data from both ILI technologies demonstrate that, for the remaining anomalies in Line 1600, adequate safety margins exist and the line is safe for operation at this time. However, Line 1600, while safe for service, should be considered for risk reduction efforts (pressure reduction), in light of the facts that Line 1600 was constructed using non-state-of-the art manufacturing methods that leave hook cracks in the long seam, hooks cracks are known to exist as verified by the recent ILI results, and the potential for an ongoing interactive threat with corrosion.

[29] *See* D.11-06-017, at 5, n.3.
[30] Line 1600 includes approximately less than ½ mile of 14-inch seamless pipe that was internally inspected in 2015 with axial magnetic flux technology. The discussion in this testimony centers around the 2012-2014 findings.

As explained in Mr. Sera's testimony, as part of the Commission-approved PSEP prioritization process, pipeline segments are sub-ranked for scheduling purposes, primarily based on the consequence of failure of each segment. Based on the Utilities' sub-prioritization risk factors of potential impact radius, long seam factors, and higher percentage of the specified minimum yield strength (SMYS) at MAOP, Line 1600 would potentially have a higher likelihood of failure and consequence of failure if pressure tested and maintained at a transmission service stress level than if it were de-rated and its transmission function replaced. Thus, a higher level of safety can be achieved through de-rating Line 1600 and replacing its transmission function.

Replacing the transmission function of existing Line 1600 and converting Line 1600 to distribution service, rather than pressure testing the line and returning it to transmission service, would provide a greater margin of safety; and do so without taking the pipeline out of service and potentially impacting customers. As explained in Mr. Sera's testimony, lowering the operating pressure on Line 1600 would permanently and significantly reduce exposure to all risk factors where the likelihood of failure or the consequences of failure are affected by operating stress level. Therefore, it is prudent for the Utilities to take this opportunity to significantly and permanently reduce long-term risks associated with this vintage, non-state-of -the-art pipe by permanently lowering its operating pressure.

V. THE PROPOSED PROJECT IS THE MOST BENEFICIAL AND PRUDENT MEANS TO ADDRESS LINE 1600

The Utilities must either pressure test, replace, or reduce the pressure on Line 1600 below a transmission level of service in order to comply with PUC Section 958 and D.11-06-017. The Utilities propose reducing the pressure on Line 1600 and replacing its transmission function with Line 3602, a state-of-the-art 36-inch pipeline that will enhance safety, reliability, resiliency, and operation flexibility. The Utilities propose to repurpose Line 1600 for distribution service to prevent the need to build additional infrastructure to connect the taps of Line 1600 to the proposed new line. In so doing, the Utilities will reduce Line 1600's MAOP below a transmission level of service, and to a level where the safety margin in distribution service is demonstrated by its operating history and addresses the risk associated with Line 1600 operating at higher pressures. Replacing Line 1600's transmission function and operating Line 1600 at a lower pressure achieves a greater margin of safety.

Reducing Line 1600's operating pressure to distribution service would permanently and significantly reduce exposure to all risk factors where the likelihood of failure or the consequences of failure are affected by operating stress (for example, the effect of higher stress levels on increased likelihood of seam rupture). In this way, as explained in Mr. Sera's testimony, long-term pipeline safety would be enhanced to a level greater than that achievable with a pressure test, given the greater overall risk reduction that results from lower stress operation.

As further discussed in the testimony of Mr. Sera, in 2011, the Utilities already proactively reduced the MAOP of Line 1600 from 800 to 640 psig to provide an additional safety margin. The Utilities subsequent in-line inspections and associated remediation work further validated the adequacy of the line's safety margin at an MAOP of 640 psig. Lowering the pressure further so that Line 1600 operates below 20 percent of the SMYS would add an additional safety margin and address future risks associated with the electric flash welded long seam. This further reduction of the operating pressure of Line 1600 aligns with the Commission's safety policy statement "…to achieve a goal of zero accidents and injuries across all the utilities and businesses…"[31] and is consistent with the Commission's efforts to "continue to strive for the safest possible operations from California's investor-owned utilities."[32] The Utilities share the Commission's goals and also strive to operate and maintain the safest possible system. And, by de-rating Line 1600, an increased level of safety will be achieved for Line 1600 beyond that which can be achieved through pressure testing and increased monitoring. As explained in the testimony of Mr. Sera, the replacement of non-state-of-the-art pipeline systems, like Line 1600, is a prudent method of system management and a comprehensive approach to minimizing risks while progressing toward continual improvement under the Transmission Integrity Management Program (TIMP).[33]

In addition, in replacing Line 1600's transmission function, the Utilities propose constructing Line 3602 using state-of-the-art manufacturing methods including pipeline enhancements to further system safety by monitoring and protecting against right-of-way intrusions and dig-ins. In this way, system safety will be significantly improved. The safety measures associated with the new pipeline are explained in the Prepared Direct Testimony of Deanna Haines.

State law and regulations require the Utilities to pressure test, replace, or remove Line 1600 from transmission service. The Proposed Project would satisfy this requirement in a manner that exceeds minimum safety requirements, further enhances system safety through the installation of a state-of-the-art Line 3602, and avoids the cost and difficulties of connecting customers currently served on Line 1600 to a new pipeline.

[31] Safety Policy Statement of the California Public Utilities Commission, July 10, 2014.
[32] CPUC, 2016 Safety Action Plan Update, at 3.
[33] 49 C.F.R. §§ 192.921, 192.935, and 192.937.

A. Pressure Testing Line 1600 would only meet the minimum requirements of Public Utilities Code Section 958 and D.11-06-017

In contrast to the Proposed Project, pressure testing Line 1600 would only meet the minimum requirements of PUC Section 958 and D.11-06-017 and would not represent the most prudent investment in the long-term safety and integrity of the system. Pressure testing would not address the long-term risks associated with electric flash welded pipe on Line 1600. The de-rating of Line 1600 and construction of a new transmission line, however, greatly enhances system safety and improves reliability, resiliency, and operational flexibility.

First, de-rating would further enhance safety by increasing the margin of safety and minimize the risks associated with operation at a transmission service stress level on 1949 flash welded legacy pipe, such as the potential for long seam flaws or unpredictable third-party damage (*e.g.*, dig-ins) occurring coincident with a long seam weld anomaly.

Second, the construction of Line 3602 would provide long-term safety and environmental benefits through installation of modern safety features, such as warning mesh above the pipeline to alert excavators they are near the pipeline and 24-hour real-time leak detection monitoring and intrusion detection monitoring on the new line.

Therefore, the Proposed Project represents the most prudent investment in system safety and should be approved to not only comply with PUC Section 958 and D.11-06-017, but to greatly enhance system safety and improve reliability, resiliency, and operational flexibility.

B. Replacing Line 1600's Transmission Function and Operating Line 1600 at a Lower Pressure Avoids Potential Service Disruptions from Pressure Testing

The Utilities acknowledge that while pressure testing is technically possible, it would be complicated and would not meet the other objectives identified above: enhanced safety through replacement of non-state-of-the-art legacy pipe, reliability/resiliency, and operational flexibility. Indeed, as explained in the Prepared Direct Testimony of Neil Navin, a pressure test of Line

1600 would be complicated and protracted, especially if additional time is needed to repair possible failures or anomalies discovered during testing.

To illustrate, sequentially removing 19 segments of an approximately 45-mile pipeline from service would occur during shoulder months and would take approximatey four years to complete the hydrotest. Each of the 19 test segments would take approximately four to six weeks to conduct, and more time to repair should leaks occur. Further, Line 1600 is potentially exposed to greater risk of unpredictable pressure test failure given the known long seam flaws (*i.e.*, hook cracks) that exist. The number of customers served off the pipeline, pipeline accessibility, and work space availability would add to the complexities of testing the pipeline. Maintaining gas service to all customers served by Line 1600 without interruption would be challenging. The pressure test plan, costs, and schedule are discussed in greater detail in Mr. Navin's testimony.

Moreover, as explained in Mr. Bisi's testimony, pressure testing existing Line 1600 prior to or without the construction of a replacement pipeline would likely require the Utilities to provide natural gas transmission service to the SDG&E service territory primarily through a single pipeline – Line 3010. If there is an extended outage on a segment for possible repairs or other contingencies, this would reduce SDG&E's total transmission capacity by approximately 100 MMcfd. Further, an outage on Line 3010 or the Moreno Compressor Station could impact the Utilities' ability to maintain continuous service to customers.

Finally, as explained by Mr. Bisi and Prepared Direct Testimony of S. Ali Yari, if Line 1600 is removed from service for pressure testing and repair of any leaks, the loss of this capacity could lead to more frequent curtailments of EG demand in San Diego. As explained in the Prepared Direct Testimony of Gwen Marelli, this is particularly true if repairs must be scheduled during periods of high sendout when gas cannot be scheduled for delivery at Otay Mesa.

As such, upon further evaluation, although the management of customer impacts is technically possible, it would be complicated and costly. Based on these complexities and the risk factors associated with continuing to operate Line 1600 as a transmission line, the prudent approach is to put a new pipeline in place and further reduce the operating pressure of Line 1600. In so doing, the Proposed Project will avoid the potential risks, complications, and costs of alternative supplies to manage customer impacts from pressure testing Line 1600. Line 1600 will be removed from transmission service and Line 3602 will be pressure tested prior to being placed into service, and thus, will comply with PUC Section 958 and Commission pipeline safety requirements and objectives.

C. A 36-Inch Replacement Line is Needed for Reliability and Resiliency

The transportation of natural gas is dependent upon pipelines and compression facilities to move the natural gas from the sources of supply to end-use customers. Installing a 36-inch replacement pipeline[34] would improve resiliency for both Line 3010 and the Moreno Compressor Station and increase Gas System and electric grid reliability.

The Gas System currently primarily relies on Line 3010 and Moreno Compressor Station to meet the overall demands of San Diego County, with Line 1600 meeting the needs of customers in the northeastern part of the county and supporting overall system capacity and peak day requirements. The San Diego metropolitan area is the seventeenth largest in the United States and of the top thirty largest metropolitan areas, it appears to be the only one so reliant on

[34] *See* Mr. Bisi's testimony for a detailed explanation of the differences in diameter and effects on SDG&E system capacity.

just one gas transmission pipeline.[35] While this has been the case for many years, implementation of State test or replace requirements provides a timely opportunity to address this vulnerability.

In the Prepared Direct Testimony of Jani Kikuts, he illustrates one plausible example of the kinds of potential impacts that could occur to core, noncore, and electric generation customers in the event of an outage on Line 3010. In this example, he shows that an outage on Line 3010 could possibly result in core customers losing service for a week or more, depending on the number of customers requiring restoration of service. A complete outage of Line 3010 would result in a loss of gas service to both SDG&E's core and noncore customers. A partial outage due to a loss of compression or pressure reduction on the pipeline is very likely to impact noncore customers and may affect core customers, depending upon its scope, location, and duration. A severe outage on Line 3010 could result in core customers losing service, and depending on the number of customers losing service and the extent of damage, customers may be without service for a week or more. In addition to residential outages and business losses, outages could affect hospitals, retirement homes, universities, schools, and the military. Furthermore, an unexpected outage on Line 3010 could result in gas curtailment of noncore customers and EG, threatening the electric grid, as explained by Mr. Yari.[36]

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[35] This is based on the Utilities' review of the U.S. Energy Information Administration (EIA) Energy Mapping System, *available at* http://www.eia.gov/state/maps.cfm?v=Natural. Seattle Tacoma metro area is served by one pipeline, but unlike San Diego, has significant supplies available at both receipt points. Miami metro area appears to have just one pipeline on the EIA mapping system, but the Utilities have found more detailed maps that show multiple pipelines. The population in 2014 for these metropolitan areas was: over 3.2 million for San Diego/ Carlsbad Metro, over 3.6 million for Seattle/Tacoma Metro, and over 5.9 million for Miami/Fort Lauderdale /W. Palm Beach Metro. *See* http://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=bkmk

[36] Mr. Yari addresses in more detail the risks associated with gas-curtailment-driven electric outages.

Contingency planning and system redundancy/resiliency can play a vital role during any major unplanned outage or pressure reduction.[37] Providing redundancy to Line 3010 and Moreno Compressor Station through approval of the Proposed Project is necessary to provide a safe, reliable, and resilient gas system in the event of unplanned outages or pressure reduction affecting the one line that almost entirely supplies San Diego County.

A new 36-inch gas pipeline would backup Line 3010 and, together with Line 3010, meet the gas demand necessary for the winter 1-in-10 year cold day design standard for all core and noncore customers.[38] As explained by Mr. Bisi, this would reduce the risk of noncore customer outages and gas curtailments of EG in San Diego, provide SDG&E personnel more time and flexibility to address maintenance issues and conduct safety inspections on Line 3010, and allow for greater free flow of supplies south of the Rainbow Station, thus reducing the reliance upon and hours of operation of Moreno Compressor Station. A new 36-inch pipeline would provide resiliency for the Moreno Compressor Station and allow gas to flow to meet system requirements

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[37] Although gas system outages have been rare, contingency planning is reasonable and prudent. To illustrate the potential for unpredictable system outages, following a scheduled pipeline safety inspection of two contiguous transmission lines (Lines 293 and 7000) running through rural parts of the San Joaquin Valley, test results indicated that additional assessments were required on three sections of the pipeline. Until further assessments and testing could be completed, SoCalGas was required to temporarily reduce the maximum operating pressure of the pipelines. These mandated pressure reductions were required in order to establish an additional margin of safety when inspection results indicated conditions may exist that pose a risk to the integrity of the pipeline. In this particular case, unreported third-party damage was the cause of the mandated pressure reductions. To help provide continued service to higher priority core and firm noncore customers in the region, SoCalGas was obligated to curtail service to certain noncore customers who had opted to receive interruptible service. The unplanned and unpreventable curtailment persisted for nearly two weeks while expedited work was conducted to return to normal operating conditions as quickly as possible. *See* CPUC Resolution G-3482, at 2-3 (dated Dec. 5, 2013).

[38] In D.02-11-073, the Commission affirmed a 1-in-35 year cold day condition as the design criteria for core service, and established a new 1-in-10 year cold day design criteria for noncore firm service. These standards were reaffirmed in D.06-09-039.

on all but the highest demand days in the event Moreno Compressor Station becomes damaged or inoperable.[39]

As such, a 36-inch replacement Line 3602 should be approved to provide much needed reliability and resiliency for both compression and pipeline service interruptions that pose a critical risk to the reliability of the SDG&E system. Increasing the diameter of the new line is a practical solution to provide a backup supply of gas to San Diego and mitigate the risks of a single point of failure scenario.

D. A 36-Inch Replacement Line is Needed for Operational Flexibility

Installing a 36-inch replacement line enhances operational flexibility by providing incremental capacity to meet peak demand requirements and future population growth in San Diego County, which is projected to grow by nearly one million people by 2050.[40] San Diego has been a potentially capacity-constrained area for quite some time, as no new pipeline capacity has been built for 15 years, despite the construction of more natural gas-fired power plants during that timeframe. Moreover, due to the intermittency of the growing portfolio of renewable power sources (solar and wind), peak demand is becoming increasingly harder to forecast, anticipate, and serve.[41] Further, as explained by Mr. Yari, as more renewable generation comes online, additional quick-start natural gas-fired generation may be needed.

As explained in Mr. Bisi's testimony, the additional capacity would be beneficial in serving EG demand at levels greater than expected or forecast on a daily or hourly basis.

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[39] Currently, an outage at Moreno Compressor Station could lead to the curtailment of EG in San Diego.
[40] San Diego Association of Governments (SANDAG) Series 13: 2050 Regional Growth Forecast (dated Oct. 15, 2013), ("SANDAG projects the region's population will grow by nearly one million people by 2050. This forecast is consistent with previous expectations although future growth rates have been reduced due to increased domestic migration out of the region. The growth in population will drive job growth and housing demand within the region – adding nearly 500,000 jobs and more than 330,000 housing units by 2050."), *available at* http://www.sandag.org/index.asp?classid=12&subclassid=84&projectid=503&fuseaction=projects.detail
[41] *See* Prepared Direct Testimonies of Mr. Bisi and Mr. Yari.

Although such peak conditions are not typically considered in the development of formal demand forecasts, these conditions occur, and are anticipated to become more common as weather conditions change and the use of natural gas to support renewable electric generation continues to increase. With the Proposed Project, on a daily basis, the capacity of the San Diego gas system will be increased by approximately 30 percent, or 200 MMcfd (assuming all transmission pipeline and compression assets are available), allowing for elevated demand conditions above the peak demand forecast.

Therefore, it is prudent to build a 36-inch pipeline to not only provide redundancy for Line 3010 and Moreno Compressor Station, but also to build incremental capacity for this potentially capacity-constrained area to reduce the risk of curtailments.

E. A Continuous 36-Inch Diameter Pipeline is Preferable from a Pigging Perspective

D.11-06-017 instructs the Utilities to address pipelines as part of PSEP so as to better enable for the use of in-line inspection tools.[42] Currently, approximately one mile of 36-inch diameter pipeline already exists in the Poway area. Thus, from a piggability perspective, it would be beneficial to maintain a continuous 36-inch diameter pipeline for the remainder of the Proposed Project for geometric consistency in light of future integrity management assessments. Complications can arise with the technical challenge of smart pigging a dual diameter pipeline. Dual diameter pipelines require the use of specialized dual-diameter in-line inspection devices, and these devices are typically limited in availability. Additionally, these devices tend to be the last tools modified with technical advancements in sensor technology. Limitations with availability also extend to the number of vendors that offer dual diameter tools in this 30-inch

[42] D.11-06-017, at 30 (Conclusion of Law 9) ("The Implementation Plan should also address retrofitting pipeline to allow for in-line inspection tools and, where appropriate, automated or remote controlled shut off valves.").

and 36-inch diameter range. Limited availability creates exposure to market forces that can affect compliance with schedules. Limited tool availability can be a significant factor when there is simultaneous demand for tools, when tools experience unpredictable outages due to breakage and downtime for repair, or when the limited number of competing vendors experience instability in their ability to support the service. Each of these factors creates potential limitations to the options available for future compliance-related inspections.

F. The Proposed Project Provides Environmental Benefits Through Emission Reductions

i. Benefits of Natural Gas as a Transportation Fuel

The Proposed Project could also help the State meet both near-term and long-term environmental and petroleum reduction goals by facilitating the delivery of natural gas for use by Natural Gas Vehicles (NGV), particularly in the heavy-duty vehicles sector. Reducing emissions and petroleum use within the transportation sector will be critical to meet the State's air quality goals, climate change policy goals, and achieve energy independence and stability for California. Since natural gas is not a petroleum product, the use of natural gas in transportation can play an important role in reducing the State's reliance on petroleum fuels and the Proposed Project would assist in delivering that fuel to the clean transportation sector in San Diego County.

Further, with the use of increasing volumes of Renewable Natural Gas (RNG), the transit sector has the potential to drive the carbon intensity of its emissions below electric buses. In addition, the California Air Resources Board (CARB) has reflected deployment of low emission, low-carbon fueled trucks, such as low nitrogen oxide (NOx), RNG-fueled trucks, as part of its 2014 Scoping Plan Update on how to meet the 2020 greenhouse gas (GHG) reduction goals.[43]

[43] SoCalGas Comments on Draft CEC AB 1257 Report, at 5-7 (dated Oct. 2, 2015).

ii. Potential Environmental Benefits at Moreno Compressor Station

The Proposed Project could also provide environmental benefits through reduced use of the Moreno Compressor Station. Moreno Compressor Station is located in the South Coast Air Basin, which has a federal designation of extreme non-attainment for the eight-hour ozone standard.

As explained by Mr. Bisi, the additional pipeline capacity that the Proposed Project provides could enable the Utilities to reduce the operational hours at Moreno Compressor Station and continue to meet the current level of demand. A 36-inch pipeline operating in common with Line 3010 can support an SDG&E demand of 630 MMcfd at times without compression required at Moreno Compressor Station. A reduction in engine utilization for compression not only reduces fuel usage and maintenance cost, but also may translate directly into emission reductions.[44] Potential reductions at Moreno Compressor Station based on current level of demand include NOx, NO, and CO along with GHG reductions for CO_2 and methane. The Utilities reported 29,302 metric tons of CO_2 equivalent (MT CO_2e) in 2013 and 15,800 MT CO_2e in 2014 of GHG combustion emissions at Moreno Compressor Station to CARB. Methane emissions from SDG&E's single compressor station at Moreno are among SDG&E's top ten emission sources.[45] Thus, a reduction in methane emissions due to less compressor blowdowns, seal losses, and engine starts at Moreno would also be consistent with the State's climate change policies such as SB 1371.[46]

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[44] *See* Attachment A to Prepared Direct Testimony of Neil Navin – San Diego Gas & Electric and Southern California Gas Co. Pipeline Safety & Reliability (PSRP) Report. Attachment XII to the PSRP Report, Moreno Compressor Station – Operation Analysis.

[45] R.15-01-008, SDG&E Natural Gas Leakage Abatement Report, Attachment 2 (dated May 15, 2015).

[46] Any potential emission reductions are estimates only. The dynamic needs of the Gas System will dictate the operational schedule of the Moreno Compressor Station.

VI. ALTERNATIVES TO THE PROPOSED PROJECT

On January 22, 2016 the Assigned Commissioner and Administrative Law Judge issued a joint ruling[47] directing the Applicants to file and serve an Amended Application by March 21, 2016 that includes, among other things, a cost analysis that compares the relative costs and benefits of the Proposed Project and various project alternatives (Alternatives).[48] Specifically, the Ruling requires that the analysis 1) quantify seven categories of benefits, and 2) apply quantifiable data to define the relative costs and benefits of the Proposed Project and the alternatives identified in the Ruling.[49] The seven categories of benefits that must be quantified are (1) increased safety; (2) increased reliability; (3) increased operational flexibility; (4) increased system capacity; (5) increased ability for gas storage by line packing; (6) reduction in the price of gas for ratepayers; and (7) other benefits identified by the Applicant.[50]

In compliance with the Ruling, the Utilities retained Pricewaterhouse Coopers (PwC) who, with input and data from the Utilities, undertook a cost-effectiveness analysis to quantify and compare the relative costs and benefits of the Proposed Project and Alternatives described in the Ruling.[51] The costs analysis includes the estimated fixed costs, the on-going operating costs, and the avoided costs (*i.e.*, costs that will not be incurred when the Proposed Project or a particular Alternative is implemented). The benefits analysis evaluates each of the seven types of benefits specifically identified in the Ruling. The full analysis has been included in the Amended Application in Volume III, but the table below indicates the benefit rank and net cost of the Proposed Project and Alternatives.

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[47] Joint Assigned Commissioner and Administrative Law Judge's Ruling Requiring an Amended Application and Seeking Protests, Responses and Replies (Ruling).
[48] Ruling, at 11-14.
[49] *Id.* at 12.
[50] *Id.*
[51] *See* Amended Application, Volume III – Cost-Effectiveness Analysis. The Cost-Effectiveness Analysis and underlying methodology were performed by PwC with input and data from the Utilities.

TABLE 1
Proposed Project and Alternatives Relative Benefit Ranking[52] and Net Costs[53]

Project Alternatives		Benefit Rank	Net Cost ($M)
A	Proposed Project (36” pipeline Rainbow to Line 2010 Route)	1	$256.2
B	Hydrotest Alternative[54]	15	$118.7
C1	Alt Diameter Pipeline, Proposed Route (10")	18	$302.7
C2	Alt Diameter Pipeline, Proposed Route (12")	18	$291.6
C3	Alt Diameter Pipeline, Proposed Route (16")	11	$241.4
C4	Alt Diameter Pipeline, Proposed Route (20")	10	$239.2
C5	Alt Diameter Pipeline, Proposed Route (24")	9	$229.6
C6	Alt Diameter Pipeline, Proposed Route (30")	8	$233.5
C7	Alt Diameter Pipeline, Proposed Route (42")	1	$341.9
D	Replace Line 1600 in Place with a 16" Transmission Pipeline Alternative	12	$560.4
E/F	Otay Mesa Alternatives[55]	13	$876.8
G	LNG Storage (Peak-Shaver) Alternative	14	$2,584.7
H1	Alternate Energy Alternative: Grid-Scale Batteries	16	$8,330.1
H2	Alternate Energy Alternative: Smaller-Scale Batteries	16	$10,010.1
I	Offshore Route	7	$1,295.5
J1	Blythe to Santee Alternative 1	3	$1,219.3
J2	Blythe to Santee Alternative 2	3	$1,157.3
J3	Cactus City to San Diego Alternative	3	$981.1
K	Second Pipeline Along Line 3010 Alternative	3	$427.1

After evaluating the net costs and benefits of the Proposed Project and Alternatives, the Cost-Effectiveness Analysis concludes that the Proposed Project is the most cost-effective, prudent alternative.

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52 Ranked from 1 through 19 with 1 being the highest rank.

53 Net costs are calculated as: Fixed Costs + Operations & Maintenance Costs + Avoided Costs. Net costs are discussed in Section IV. C of the Cost-Effectiveness Analysis.

54 In the Ruling, Alternative B is referred to as the “No Project Alternative” and defined as hydrotesting Line 1600 in sections and repairing or replacing pipeline segments as needed. The Utilities refer to Alternative B herein as the “Hydrotest Alternative.”

55 The Ruling identifies two alternative projects utilizing the Otay Mesa receipt point: Non-Physical (Contractual) or Minimal Footprint Solutions (Alternative E); and the Northern Baja Alternative (Alternative F). Ruling, at 13. Both of these rely upon the use of Otay Mesa receipt point (Otay Mesa) capacity in place of the Proposed Project. Accordingly, the Applicants will refer to the two alternatives as a single project titled “Otay Mesa Alternatives.” *See* Prepared Direct Testimony of Gwen Marelli.

This is because, as explained in the Cost-Effectiveness Analysis attached to the Amended Application, the Proposed Project provides the greatest degree of benefit relative to its cost. When considering both net project costs and benefits, the Proposed Project is the most cost-effective and prudent option, as it provides more benefits than any of the alternatives except for the 42-inch diameter pipeline, which has an equal benefit rank of #1, but costs approximately $85 million more (on a net cost basis) than the Proposed Project.

VII. TIME IS OF THE ESSENCE

The Utilities must take action due State law and D.11-06-017 to either pressure test, replace, or de-rate Line 1600. Pressure testing and, if necessary, repairing Line 1600, which is over 65 years old, would not produce the greater safety margin that can be achieved with de-rating Line 1600 and constructing a new, state-of-the-art Line 3602 transmission line. Moreover, keeping Line 1600's transmission function or replacing it with a 16-inch (or smaller) pipeline, would be inadequate to address the additional reliability, resiliency, and operational flexibility needs of the Gas System. As discussed above, SDG&E core, noncore, and EG customers are dependent on one pipeline to meet gas demand and provide reliable service. The faster the Utilities put this new pipeline into service, the faster the Utilities can deal with threats to both the gas system reliability and electric grid reliability in San Diego County.

As explained in Mr. Navin's testimony, it would take at least five more years to bring this project into service assuming no unforeseen regulatory or environmental delays. Further, as pointed out by Mr. Navin, delay would add additional costs to the project and needlessly delay PSEP implementation. In order to avoid extending our estimated project timeline, the Utilities request that the Commission deem this Amended Application complete in an expeditious manner.

VIII. CONCLUSION

Although alternatives exist that may each address a single objective of the Proposed Project, the Proposed Project offers the only approach that can achieve all objectives in a manner that would sufficiently minimize the potential impacts on customers, the economy, and the environment. For example, replacing Line 1600's transmission function with a new line would provide a greater safety margin than pressure testing Line 1600. As another example, it would make little sense to replace Line 1600 with an identical 16-inch diameter pipeline to minimally comply with State test or replace requirements, only to build another pipeline in the future to address the system need for reliability, resiliency, and operational flexibility.

The Proposed Project presents a unique opportunity to not only achieve shared safety enhancement objectives in compliance with State law, but also to improve the reliability, resiliency, and operational flexibility of the integrated Gas System. The Commission should approve the Proposed Project without delay and authorize construction of a 36-inch replacement transmission to enhance the safety and integrity of the Utilities' integrated Gas System and enable the Utilities to meet additional reliability, resiliency, and operational flexibility needs, and authorize the Utilities to include Proposed Project costs in integrated backbone transmission system rates.

IX. QUALIFICATIONS

My name is Douglas M. Schneider. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. I am the Vice President of Gas Engineering and System Integrity for both SDG&E and SoCalGas.

I joined SoCalGas in 1991 as an engineer and have held a number of engineering and related roles including Technical Services Manager, Pipeline Integrity Manager, Project Manager, Engineering Design Manager and Director of Pipeline Integrity. I left SoCalGas briefly, from 1997 to 2001, and during this time held the title of Vice President of Sales and Marketing for Rohrback Cosasco Systems, a manufacturer of corrosion control instrumentation and related systems. I was promoted into my current position in January 2014.

I am responsible for gas engineering, measurement, gas enterprise asset management, and pipeline integrity policies and programs for both SoCalGas and SDG&E. I am a registered Professional Engineer with a Master's Degree in Business Administration from California State University, Fullerton, and a Bachelor of Arts degree in Chemistry from Rutgers University.

I have previously testified before the California Public Utilities Commission.

This concludes my prepared direct testimony.