BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms.	R.11-02-019 (Filed February 24, 2011)

COMMENTS OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902 M) ON PROPOSED REVISIONS TO G.O. 112-E

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Per the Administrative Law Judge's Ruling Setting Schedule for Filing Comment on Proposed Rule Changes to General Order 112 issued on July 8, 2014, Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) submit the following comments on the Proposed Revision of the Safety and Enforcement Division (SED) to General Order (GO) 112-E.

SoCalGas and SDG&E commend SED Staff for their proposed revisions to GO 112-E and appreciate SED's consideration of SoCalGas and SDG&E's September 27, 2013 comments and incorporation of some of SoCalGas and SDG&E's proposed revisions. SoCalGas and SDG&E largely welcome and support the revisions proposed by SED, but offer a few proposed clarifications and suggested changes.

SoCalGas and SDG&E have limited our comments to areas where SED's proposed revisions do not address the practical implications of incorporating regulatory changes into a natural gas utility's operations, would create economic inefficiencies, or would result in arduous or expensive reporting requirements without corresponding pipeline safety benefits. Where applicable, and in order to avoid repeating previously stated arguments, SoCalGas and SDG&E incorporate by reference the arguments made in our September 27, 2013 comments. SoCalGas and SDG&E maintain that the proposed revisions presented therein would improve GO 112-F, appropriately respond to issues identified by SED, provide logical alternatives, and utilize economic efficiencies.

I. INTRODUCTION AND SUMMARY

In issuing GO 112-F the Commission should be aware of the significant amount of time and resources necessary to effectuate the proposed changes. As the Code of Federal Regulations recognizes, various factors such as the relevancy of the data, regulatory burden, recordkeeping and cost and benefits are all elements that should be considered during a proceeding to add, amend, or repeal a procedural regulation.[1] This same guidance should apply to the Commission's efforts to add and amend its GO 112-E regulations. Changes in regulatory requirements, even seemingly minor changes, may require significant modifications to SoCalGas' and SDG&E's automated scheduling, data collection and work process systems. Regulatory changes may also require the development of revised written procedures, the development of new employee and contractor training materials, and formal training of all impacted personnel and contractors. The process takes time, and must be coordinated so as to minimize the impact on other safety and compliance related work.

In the period between the first proposed changes to GO 112-E and now, SoCalGas and SDG&E have accelerated work on their Pipeline Safety Enhancement Plan; allotting additional personnel and resources to plan implementation. Furthermore, other proceedings before the Commission may further impact pipeline integrity management practices and require additional changes.[2] Institutionalizing changes will require additional time and resources to update

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[1] 49 CFR §190.331 Petitions for rulemaking.

(c) If the potential impact of the proposed action is substantial, and information and data related to that impact are available to the petitioner, the Associate Administrator or the Chief Counsel may request the petitioner to provide—

(1) The costs and benefits to society and identifiable groups within society, quantifiable and otherwise;

(2) The direct effects (including preemption effects) of the proposed action on States, on the relationship between the Federal Government and the States, and on the distribution of power and responsibilities among the various levels of government;

(3) The regulatory burden on small businesses, small organizations and small governmental jurisdictions;

(4) The recordkeeping and reporting requirements and to whom they would apply…

[2] For example, the cost and timing of implementing these proposed changes is further complicated by proposals in PG&E's Gas Transmission and Storage Rate Proceeding (A.13-12-013) to modify how PG&E classifies its transmission pipelines. The proposal potentially reclassifies a significant number of distribution pipelines as transmission – requiring that transmission pipeline safety regulations apply to those pipelines. SoCalGas and SDG&E have filed a motion to transfer consideration of this issue into this Rulemaking.

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procedures and training programs, quality-control the reported data, follow-up on training to address data errors, and maintain overall data integrity. Therefore, SoCalGas and SDG&E ask that the Commission, in adopting proposed revisions to GO 112-E, also adopt a period of time of no less than one full calendar year for the new requirements to go into effect and reporting the following year to align with Pipeline and Hazardous Materials Safety Administration's annual reporting deadlines. Meaning, a period of no less than two years may be needed before the information can be readily produced for reporting purposes, depending on the specific information and processes impacted. The order could direct natural gas utilities to begin implementing the new requirements immediately, but allow the utilities sufficient time to operationalize the new regulations.

In addition to an investment of time, implementation of new regulatory requirements will require an investment of funds. The costs required to implement these significant changes are not currently included in rates, nor are they included in SoCalGas' and SDG&E's upcoming general rate case application.[3] The more time the utilities are provided to implement the changes, the greater their ability to coordinate those changes with ongoing work in a cost efficient manner. Thus, the less time provided for implementation, the greater the costs of implementation will be and the greater the impact on rates. In order for the system changes and training described above to be implemented without diverting funds from other safety-related work, the Commission should adopt a mechanism to allow the natural gas utilities to recover the costs of implementing the new GO 112-F regulatory requirements. As such, SoCalGas and SDG&E propose the creation of a balancing account to record the costs incurred to implement these regulatory changes. These recorded costs would be incorporated in transportation rates charged to ratepayers in connection with SoCalGas' and SDG&E's annual regulatory account balance update filing. This process would be used until the costs of compliance could be included in a future rate proceeding.

[3] As just one example, new Section 143.1(b) requires gas leakage survey of transmission pipelines using leak detecting equipment at least twice each year and at intervals not exceeding 7 ½ months. Company leak survey procedures require gas leakage survey of transmission pipelines using leak detecting equipment. However, Class Locations 1 and 2 only require annual leak surveys (Class Locations 3 and 4 do require surveys at least twice per year). To increase frequency in Class Locations 1 and 2 would be a significant resource requirement that is not included in rates nor included in upcoming rate requests. Implementation of this change requires an additional funding mechanism to implement.

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II. CLARIFICATIONS AND COMMENTS ON SED PROPOSED REVISIONS TO GO-112-E

SoCalGas and SDG&E offer proposed revisions to these Proposed Rule Changes (PRC) and explain why such clarifying edits are needed in the subsections below.

a. PRC-1: Remove the reference with to GO-112-E to 49 CFR, Part 190, per agreements with PHMSA, which applies only to federal processes. This also provides additional clarity and addresses a minor housekeeping issue.

No comments or proposed changes.

b. PRC-2: Remove the reference with to GO-112-E to 49 CFR, Part 190, per agreements with PHMSA, which applies only to federal processes.

No comments or proposed changes.

c. PRC-3: Provide clarification on existing GO-112-E terms and define new terms related to new metrics or more stringent requirements than otherwise required by 49 CFR, Part 192.

i. Public Attention

The definition of public attention should be limited to incidents where it is determined that the "public attention" is attributable to a natural gas operator's facilities. This will avoid the reporting of incidents unrelated to the pipeline operator's facilities.

Additionally, in order to allow a reasonable timeframe for the reporting to be made, the time of discovery should be defined as when the natural gas pipeline operator determined that the concerns identified in the calls/complaints are attributable to the pipeline operator's facilities. The applicable reporting window should commence upon such determination.

Finally, to avoid unnecessary reporting regarding known or planned activity, phone calls regarding planned maintenance operations (*e.g.*, calls from customers to report gas odor attributable to the deliberate release of natural gas as part of scheduled maintenance activities), should be exempted from this new reporting requirement. Therefore, the definition of "Public Attention" should be revised as follows:

> Public Attention means any event that escalates to a level that initiates calls/complaints of ~~concerning~~ a common safety concern being submitted to a utility from 10 or more individuals or organizations <u>attributable to the operator's facilities</u>. This can include, for example, large scale reports of the smell of gas by customers in the vicinity of an operator's gas facilities. Public Attention criterion does not necessarily include an individual, or a crowd of persons, watching work being performed on company facilities. <u>Planned operations where the customers have been notified are also excluded.</u>

ii. Near-miss Events

The first challenge with this proposal is the definition of a near-miss event. For this to be a meaningful metric, it is essential to create a definition that is workable, reproducible, and consistent across operators. Further, once defined, near-misses may still go undetected, or be detected years after the event occurred. As such, the Commission should limit the reportable near-miss events to those events that the operator knew to have occurred. Finally, near-miss events should be defined as only including "otherwise non-reportable incidents" that had the potential to be reportable. As currently written, the definition would require duplicative reporting by requiring separate reporting of "otherwise reportable incidents."

Reporting related to an "incorrectly mapped pipeline facility" should be made more specific to avoid unnecessary reporting. Reporting all mapping inconsistencies, no matter how de minimis, would require additional resources to more frequently and review and update maps absent a corresponding increase to safety. The more important near-miss event metric would be the discovery of an incorrectly mapped pipeline facility during construction activity. SoCalGas and SDG&E propose the following revisions to the proposed definition of near-miss event:

> Near-miss events mean unplanned, undesired, events, that the operator knew of, and that adversely affect an operator's facilities or operations but do not result in injury, illness, damage, release of gas, loss of gas service, or over-pressurization of operator's gas pipeline facilities, or in an otherwise non-reportable incident, but had the potential to do so. Such events can include, but are not limited to:
>
> (a) A subsurface pipeline facility not marked or mismarked for excavation purposes;
>
> (b) Excavation activity near a pipeline facility conducted without ~~an~~ a valid Underground Service Alert ticket;
>
> (c) The incorrect operation of a~~n~~ ~~incorrect~~ valve or pressure regulator;
>
> (d) An incorrectly mapped pipeline facility discovered during construction activity;
>
> (e) Work activity in which a standard, procedure, or process approved by an operator was correctly applied but the activity, nonetheless, resulted in creating a situation or condition where damages or injuries could have easily occurred.

iii. High Consequence Area (HCA)

SoCalGas and SDG&E support the Commission's goal of increasing the amount of pipeline subject to subpart O assessment requirements. However, it is important to be mindful of the time and expense associated with the inclusion of additional HCA mileage. Currently, PRC-3's definition of HCA only notes the following with regard to timing: "HCAs newly identified through the Commission's restriction on Method 2 shall be scheduled for baseline assessment in accordance with 49 CFR §192.905(c)." 49 CFR §192.905(c) requires:

> If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

While it is possible to incorporate these newly designated HCAs into the baseline assessment plan within one year from adoption of the proposed rule change, it would not be possible to complete the baseline assessment in an expedited manner without additional resources or shifting resources away from other pipeline safety efforts. Regardless, the Commission should also more clearly provide the timeframe for the completion of the baseline TIMP assessment. Specifically, 10 years, in alignment with the requirements set forth in 49 CFR 192.921 for new High Consequence Areas. Therefore, the definition of High Consequence Area should be revised as follows:

> High Consequence Area (HCA) is defined by 49 CFR §192.903, which allows two different methods to be used towards determining locations where HCAs exist. However, in an effort to be more conservative towards ensuring the safety in areas of more densely populated areas, the Commission restricts the use of Method 2 in 49 CFR §192.903, in determining HCAs to pipeline segments of 12-inches or less. Accordingly, the Commission modifies paragraph (2) of the High Consequence Area defined by 49 CFR §192.903 to read as follows:
>
> > (2) The area within a potential impact circle of a pipeline 12-inches or less in diameter containing - HCAs newly identified through the Commission's restriction on Method 2 shall be scheduled for baseline assessment in accordance with 49 CFR §192.905(c) <u>and 49 CFR §192.921(f)</u>.

d. *PRC-4: Require the reporting of overpressure and underpressure events on all gas pipeline systems.*

No additional comments or proposed changes.

e. *PRC-5: Incorporate minor updates in federal regulations and implement requirements for the reporting of metrics discussed in the June 27, 2013 Metrics Workshop.*

iv. <u>Leak Response Time</u>

SoCalGas and SDG&E currently collect and track leak response time data and do not oppose reporting of such information to the Commission. SoCalGas and SDG&E note, however, that in the proposed revisions to GO 112-E, SED should limit section 123.2(c) to response time and not include the repair time since repair time is already captured in section 123.2(b).

Therefore, response time would end when the first company responder arrives on the scene. SoCalGas and SDG&E propose the following revision:

> **123.2** At the same time copies of the reports required by paragraph 123.1 are submitted, each operator shall submit, in a format and guidance provided by the Commission's Safety and Enforcement Division or its successor, the following information to demonstrate to the Commission and the public an Operator's efforts towards minimizing the risk from system leaks and failures:
>
> a) Number of gas leaks repaired associated with grades, causes, pipeline materials, sizes, and decades of installation.
>
> b) For leaks repaired in the calendar year, show time between finding the leak and its repair in intervals of 0-3 months; 3-6 months; 6-9 months; 9-12 months; 12-15 months; and greater than 15 months. For the aggregated value of leaks repaired greater than 15 months, segregate the value into leaks that are never regraded; regraded once; regarded twice; regraded three times; and regraded more than three times.
>
> c) Response times in five-minute intervals, segregated first by business hours (0800 – 1700 hours), after business hours and weekends/legal state holidays, and then by Division, District, and/or Region, to reports of leaks or damages reported to the Operator by its own employees or by the public. The intervals start with 0-5 minutes, all the way to 40-45 minutes, an interval of 45-60 minutes and then all response times greater than 60 minutes. The timing for the response starts when the utility first receives the report and ends when ~~an Operator's qualified representative determines, per the operator's emergency standards, that the reported leak is not hazardous or the Operator's representative completes actions to mitigate a hazardous leak and render it as being non-hazardous (i.e., by shutting off gas supply, eliminating subsurface leak migration, repair, etc.) per the operator's standards. In addition, the Operator must report, using the same intervals, the times for~~ the first company responder ~~to~~ arrive<u>s</u> on scene.

v. <u>Excavation Damage Prevention Related Data</u>

SoCalGas and SDG&E recommend that the new proposed reporting requirements be revised to remove the reporting of person-days and costs to perform all USA ticket response activities. Instead, providing a total employee hour metric would provide sufficient transparency in resources dedicated to (1) excavation field meetings, (2) stand-by activities for preventing damage to subsurface facilities during an excavation, (3) mark and locate activities, and (4) other subsurface damage prevention activities. Additionally, reporting on "all other" activities should only include "field" activities. These revisions will provide sufficient information, while also lowering the resources necessary to comply and minimize the impact on customer rates. SoCalGas and SDG&E propose the following revision:

h) Excavation Damage Prevention Related Data

1. Number of excavation damages and related costs involving homeowners;

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2. Number of damages and related costs involving agencies (i.e., Caltrans, non-pressurized sewer, etc.) excluded per California Government Code 4216 (GC4216);

3. Total hours related to USA ticket response activities

3. Total employee hours ~~Number of person-days, along with total costs,~~ devoted to: i) excavation field meetings (per GC4216); and ii) stand-by activities for preventing damage to subsurface facilities during an excavation;

4. Total employee hours ~~Number of person-days, along with total costs,~~ devoted to: i) mark and locate activities (per GC 4216); and ii) all other field employee subsurface damage prevention activities excluding those from paragraph 3 above.

vi. Public Liaison Activities

SoCalGas and SDG&E recommend that Public Liaison Activity reporting be limited to the annual meetings with local fire departments having fire suppression responsibilities required by California Public Utilities Code Section 956.5. These are the only Public Liaison Activities which require meetings. Other public liaison activities may permissibly occur through correspondence. For example, federal regulations require maintaining liaison with fire, police and other public officials, but don't require annual meetings.[4] As such, reporting public liaison activities with police and other appropriate emergency response public officials is unnecessary and would require an undue amount of time and resource since there is more flexibility as to how and when the liaison activities may take place.

Additionally, the Commission should not require the listing of public agencies which did not attend a public liaison meeting on the operator's web site. As discussed above, there are means to maintain liaison with public agencies (save those required by California Public Utilities Code Section 956.5) that do not involve in-person meetings. Good relationships between operators and first responders are essential to public safety and listing public agency non-attendance could have a detrimental effect on those relationships as it would likely be viewed negatively by any first responders who may not have been able to attend a particular session. SoCalGas and SDG&E use their relationships to emphasize the importance of such sessions. Often there are legitimate reasons for a department not to attend a session. Publicizing lack of attendance by a department under such circumstances would undermine, rather than encourage, supportive relationships between pipeline operators and first responders. Therefore, the definition of Public Liaison Activities should be revised as follows:

j) Public Liaison Activities with Fire Departments

[4] *See* 49 CFR Parts 192.615 and 195.402.

1. The number of in-person public liaison activities scheduled by the Operator with local fire department having fire suppression responsibilities

in the area where Operators transmission and distribution lines are located and the number of in-person public liaison activities actually performed along with available information ~~details~~ to explain what caused the difference between the scheduled and performed liaison activities.

2. A summary of local fire department having fire suppression responsibilities in the area where Operators transmission and distribution lines are located (by county and city ~~agency~~ name) to which the Operator provided notice of, and made available for participation, its annual liaison sessions during each of the five calendar years preceding the reporting year. ~~The summary must also denote which agencies were able to have representation at the session.~~

~~3. In an effort to provide a convenient resource for the public to use towards confirming that Operators and first responders continue to work together in better coordinating responses to emergencies, each Operator shall make the same information provided per paragraph 2 above available on its website with a link to the same information provided on the CPUC website. Attendance of agencies at liaison sessions is voluntary and may be dependent on agencies having to allocate resources to emergencies that occur when sessions are scheduled.~~

f. PRC-6: Minor housekeeping issue.

No comments or proposed changes.

g. PRC-7: Clarify the requirements for proposed installation reports and adjust the cost thresholds for reporting, that were determined many decades ago, for inflation.

Currently, the California Public Utilities Code and Commission precedent make clear that a utility need not obtain a CPCN for pipeline construction activity that is necessary in the ordinary course of its business and is located in a city or county in which it already is providing service.[5]

PRC-7's reference to the Commission's CPCN introduces ambiguity as to what GO 112-F will require in order to construct a new pipeline. Although it appears clear that the Commission is not requiring a CPCN for operators not "commencing service for the first time" (e.g., operators who are already providing service to the city or county wherein the pipeline is located), the potential for misinterpretation should be entirely eliminated. Adoption of a new requirement in GO 112-F that even arguably requires pipeline operators submit to a CPCN for all

[5] *Se*e Cal Pub Util §1001(Section 1001 provides that a utility is not required to secure a CPCN "for an extension within any city or county within which it has theretofore lawfully commenced operations . . . or for an extension within or to territory already served by it, necessary in the ordinary course of business."); *see also* Decision 07-01-014.

new pipeline installation projects introduces needless ambiguity and could undermine the Commission's safety objectives by increasing the costs of and delaying the start of work on new pipeline installation projects. Such ambiguity and potential negative consequences can be eliminated by adopting the following revisions:

> "Construction of a new pipeline" means the installation of pipeline that will serve as a loop or extension to an existing pipeline or as an independent or stand-alone pipeline, any of which will be placed in service for the first time by an operator who filed a Form PHMSA F-7100.1-1 for the calendar year preceding the year in which construction takes place. Should a CPCN be required, an ~~An~~ operator commencing service for the first time shall file a Proposed Installation Report with the Commission after receiving Certificate of Public Convenience and Necessity (CPCN) approval from the Commission and prior to the start of construction of the approved project. A CPCN is not required for an extension within any city or county within which an operator has lawfully commenced operations or for an extension within or to territory already served by it, necessary in the ordinary course of business.

h. PRC-8: Minor housekeeping issues.

No comments or proposed changes.

i. PRC-9: Place limitations on how long plastic pipe can be stored unprotected outdoors.

No additional comments or proposed changes.

j. PRC-10: Provide clarification, specify requirements related to the prioritization and repair of leaks, and to confirm that employees performing covered tasks are qualified using equipment similar to that used in operations.

SED's new proposed rule on encroachments contains ambiguity that could result in unintended negative consequences. Specifically, the proposed requirement that if an encroachment is unresolved after 180 days the utility must "discontinue service to the pipeline system" is ambiguous as to what is meant by "pipeline system." Without a definition of "pipeline system" this could result in a significant number of customer's having their service discontinued even if the system extends well beyond the encroached upon segment of pipeline. The same desired safety effect could be accomplished by discontinuing service to the encroached upon segment of pipeline. To eliminate the ambiguity of what discontinuing service to the "pipeline system" would entail, SoCalGas and SDG&E propose the following revisions:

> 143.5 Encroachments – With the exception of gas pipeline facilities related to installations in gas meter rooms or other specially designed indoor locations where an outdoor meter installation is not possible or practical, a utility

transporting LNG, natural gas or other gas shall not construct any part of a LNG, natural gas or other gas pipeline system under a building. In addition, the utility shall not allow constructed encroachments on to its pipeline right-of-way that would hinder maintenance activities on the pipeline or cause a lengthy delay in accessing its pipeline facilities during an emergency. If the utility finds a building or other encroachments built over a pipeline system after the effective date of this section, then the utility may require the party causing the encroachment to remove the building or other encroachment from over the pipeline or to reimburse the utility for its costs associated with relocating the pipeline system.

The utility shall determine, within 90 days after discovering the encroachment, whether the encroachment can be resolved within 180 days. If the utility determines that the encroachment cannot be resolved within 180 days, the utility shall, within 90 days of discovery of the encroachment, submit to the CPUC a written plan to resolve the encroachment within a period longer than 180 days. The CPUC may then extend the 180-day requirement in order to allow the party causing the encroachment and the utility to implement the written plan to resolve the encroachment. If the utility does not submit a written plan, and the encroachment is not resolved within 180 days of discovery, the utility shall discontinue service to the pipeline segment which is being encroached upon ~~pipeline system~~. The utility must provide written notice of any imminent service discontinuance per this section to the Commission 30 days prior to discontinuing service.

k. *PRC-11: Provide clarification for test requirements pertaining to all pipelines, provide clearance requirements not specified in federal regulations, and to align clearance requirement in GO-112-E with the clearance requirement contained the Commission's GO-128.*

No additional comments or proposed changes.

l. *PRC-12: Establish a section within GO 112-E to specify recordkeeping requirements related to transmission lines.*

No comments or proposed changes.

m. *PRC-13: Minor housekeeping issues.*

No comments or proposed changes.

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n. PRC-14: Incorporate new requirements related to Operator's mobile LNG operations.

SoCalGas and SDG&E propose edits to clarify that the new regulation is applicable only to Operator's mobile LNG operations.[6] Currently, SED describes the PRC as applying to "Operator's mobile LNG operations," but the language of the regulation lacks the same specificity. The following proposed revisions to Section 162.4 would clarify that the regulation is directed at Operator owned mobile LNG equipment:

> All operators must include Operator-owned mobile LNG equipment within the written operations and maintenance plans required by 49 CFR, Part 192, §192.605, to the extent that they own, operate, or utilize mobile LNG equipment. Such operators must provide written, detailed procedures for the operation and maintenance of their mobile LNG units which conform to the requirements of 49 CFR, Part 193, §193.2019(a). Moreover, these procedures must include a requirement to perform operational tests of Operator-owned mobile LNG equipment, after any modifications are performed to the equipment (including computer equipment and software) that could affect equipment operation, before using modified equipment for actual field use.

o. PRC-15: Minor housekeeping issues.

No comments or proposed changes.

p. PRC-16: Minor housekeeping issues.

No comments or proposed changes.

q. PRC-17: Minor housekeeping issues.

No comments or proposed changes.

r. PRC-18: Minor housekeeping issues.

No comments or proposed changes.

s. PRC-19: Implement a new subpart within GO 112-E to include whistleblower protections already established as a regulation by D.12-12-009.

No comments or proposed changes.

III. CONCLUSION

SoCalGas and SDG&E would like to once again reiterate their appreciation for SED's efforts. SoCalGas and SDG&E share the Commission's commitment to enhancing the safety

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[6] PRC-3 proposes the following definition for "Operator":

> Operator means any utility, person or entity operating a natural gas transmission or distribution system, including master-meter distribution system subject to PU Code Section 4351-4361, or a propane gas (LPG) distribution system subject to PU Code Section 4451-4465.

and reliability of California's natural gas transmission infrastructure and look forward to continuing to work closely with Commission Staff to achieve this goal.

Respectfully submitted,

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