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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Adopt Rules and Procedures Governing Commission-Regulated Natural Gas Pipelines and Facilities to Reduce Natural Gas Leakage Consistent with Senate Bill 1371.	Rulemaking 15-01-008 (Filed January 15, 2015)

JOINT COMMENTS OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 G), AND SOUTHWEST GAS CORPORATION (U 905 G) ON ADMINISTRATIVE LAW JUDGE'S RULING ENTERING NEWLY REVISED NATURAL GAS LEAK ANNUAL REPORTING REQUIREMENTS INTO THE RECORD AND SEEKING COMMENTS

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I. INTRODUCTION

Pursuant to the January 26, 2016 Administrative Law Judge's (ALJ) Ruling Entering Newly Revised Natural Gas Leak Annual Reporting Requirements Into the Record and Seeking Comments (Ruling), Southern California Gas Company (SoCalGas), San Diego Gas & Electric Company (SDG&E), and Southwest Gas Corporation (Southwest Gas) (collectively, the Joint Utilities) hereby submit their joint comments on the California Public Utilities Commission (CPUC) Safety and Enforcement Division's (SED) proposed changes to the revised data request and annual report template found in Attachments 1, 2, and 3 of the Ruling (Revised Report Template).

The Joint Utilities appreciate the enhancements proposed by SED, particularly with respect to their collaboration with the California Air Resources Board (ARB) and the respondents in standardizing the emission factors in Appendix 9, as a consistent reporting methodology will enable a more accurate comparison between systems. As requested in the Ruling, the Joint Utilities generally agree that SED's enhancements meet the requirements of Senate Bill (SB) 1371 and the Scoping Memo's objectives for the annual reporting requirements. There are only a few areas where the Joint Utilities recommend a substantive change from the

Revised Report Template or where future annual requirements (beyond the May 15, 2016 reports) may need to be further refined in the final Phase 1 Commission Decision. The Joint Utilities' recommended changes are noted below to Attachments 1, 2, and 3. Suggested changes by the Joint Utilities to the 9 appendices in Attachment 3, which are excel spreadsheets, are noted in table format in Attachment A.

II. JOINT UTILITIES' COMMENTS ON PROPOSED CHANGES TO THE MAY 15TH DATA REQUEST AND REPORT TEMPLATE (ATTACHMENT 1)

A. The Baseline Year, for Comparison Purposes, Will Be 2015.

As noted in previous comments on the annual reporting requirements,[1] the Joint Utilities support using calendar year 2015 as the baseline report year (to be reported on May 15, 2016). This assumes, however, that the gas corporations' May 15, 2016 reports will reflect methane emissions data based on consistent definitions, formulas, protocols, and methodologies. Consistent with the Scoping Memo, reporting at this point remains an iterative information-gathering process until a final Phase 1 Commission Decision is issued in Q4 2016.[2] Accordingly, to the extent that there are material gaps and inconsistencies that may not produce an apples-to-apples comparison for similar system components among gas corporations, the determination of a "baseline" year may need to be reevaluated. Additionally, how such a baseline is to be used for compliance and enforcement (for example, for purposes of establishing any required reduction targets) is a separate issue in the Scoping Memo that should be vetted by

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[1] *See* Joint Utilities' Comments on ALJ's October 13, 2015 Ruling Regarding Annual Reporting Requirements, at 2.

[2] *See* Scoping Memo, at 5. *See also* ALJ's Email Ruling Seeking Comments Regarding Annual Reporting Requirements, Directing Staff to Develop a Revised Annual Report Template by the end of December 2015, and Addressing Other Procedural Matters, dated Oct. 13, 2015 ("It is possible that a Phase 1 decision in this proceeding could direct further refinements to the Annual Report Template based on proceeding developments and information trends, etc.").

stakeholders in the comment period following the CPUC/CARB Workshop on Targets, Compliance, and Enforcement scheduled for March 2016.[3]

B. Change in the Reporting Year From Fiscal Year to Calendar Year for All Information Including the System Leak Rate.

The Joint Utilities support changing reporting dates to be calendar year. As noted in previous comments,[4] the May 15th submission date is reasonable primarily because the Joint Utilities rely on information that is gathered and provided within other agency reports for the SB 1371 report. These reports submitted to other agencies are due earlier in the year and are also based on calendar year reporting. Per the Joint Utilities' request[5] for procedural clarification, the ALJ's October 13, 2015 Email Ruling directed SED to develop a revised Annual Report Template (to be used for the May 15, 2016 mandatory report) and the Joint Utilities understand that SED will issue a data request with a revised spreadsheet template incorporating any changes from this comment period by March 15, 2016.[6] Depending on how extensive the changes are to the template, the May 15, 2016 deadline for submission of the reports may need to be extended to afford enough time for respondents to compile the responsive data. There is also a possibility that calendar year 2015 data may not be entirely available in the detailed form requested because respondents may not be able to retroactively alter their information-gathering process for historical information.

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[3] *See* Scoping Memo, at 18 (noting Commissioner/ALJ Ruling Issuing CARB/CPUC Staff Proposal on Targets, Compliance, and Enforcement in June 2016 after the May 15, 2016 reports are submitted and Initial and Reply Comments on CARB/CPUC Staff Proposal and Phase 1 Scoping Questions #8-19 in July 2016).
[4] *See* Joint Utilities' Comments on ALJ's October 13, 2015 Ruling Regarding Annual Reporting Requirements, at 2.
[5] The request was also on behalf of Pacific Gas & Electric Company (PG&E).
[6] Ruling, at Ordering Paragraph (OP) 4.

C. Add a Row for Report Emissions Caused by Catastrophic Failures Such as Pipeline or Storage Well Failures.

It is unclear from the Revised Report Template what the definition of a "catastrophic failure" for purposes of the reporting template.[7] SED's explanation in Attachment 1 of the Ruling notes that this is pursuant to the Joint Parties'[8] suggestion to "capture the amount of methane emissions from large accidents."[9] The intent of SB 1371 is to reduce methane emissions from system leaks by establishing "best management practices (BMPs)."[10] Adding a specific focus on isolated events stands to distract from that intent, and could lead to reporting of emissions that are outside of the scope of SB 1371. To avoid ambiguity, the Joint Utilities recommend that "catastrophic failure" not be included as a separate and distinct line item in SB1371's reporting. Instead, only those malfunctions of equipment and associated emissions that could have been reduced with BMPs beyond safety-related and integrity management

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[7] In ARB's comment box for "unusual catastrophic events" in Appendix 8, it is defined as a "rare event with large emissions (e.g., pipeline well failure, storage well failure, etc.)." This is still a vague definition for reporting purposes.

[8] The Joint Parties are the Environmental Defense Fund (EDF) and the Utility Workers Union of America (UWUA). It is worth noting that this suggestion was procedurally improper because it was noted in the Joint Parties' *reply* comments on the annual reporting requirements and was not in any way responsive, let alone in opposition, to another parties' opening comments. In fact, it was responsive to their own opening comments. *See* Joint Parties' Reply Comments, at 7 (dated Nov. 6, 2015) ("*The Joint Parties* [EDF and UWUA] mentioned in the *Joint Parties* Comments [EDF and UWUA] that leaks on storage facilities, gathering lines and intentional releases should be included in the reports and in the database as well as emissions from any other Commission regulated facility. . . . The Joint Parties recommend that these episodic releases [like Aliso] be included in the reports . . . .") (emphasis added). This suggestion should have been suggested in opening comments to afford other parties the opportunity to respond in accordance with due process. *See, e.g.*, Rule 14.3(d) of CPUC's Rules of Practice and Procedure (noting that replies to comments shall be in response to "comments of other parties"). SoCalGas/SDG&E note this procedural issue because there appear to be recurring reply comments that either do not respond to other parties' opening comments or refer to oral statements made during informal workshops that are not part of the record. *See, e.g.*, Joint Parties' Reply Comments, at 5, 8, and 9 (dated Nov. 6, 2015); EDF Reply Comments, 7-9 (dated Apr. 22, 2015).

[9] Ruling, Attachment 1, at 2.

[10] "Best practice" is not defined in SB 1371. However, as an example, according to the EPA's Economic Benefits of Runoff Controls Glossary, a BMP is "a practice or combination of practices that are determined to be the most effective and practicable (including technological, economic, and institutional considerations) means of controlling point and nonpoint source pollutants at levels compatible with environmental quality goals." *Available at* http://ofmpub.epa.gov/sor_internet/registry/termreg/searchandretrieve/glossariesandkeywordlists/search.do?details=&vocabName=Runoff%20Control%20Econ%20Ben%20(1995)

programs should be included in the scope of SB 1371 reporting. In the event of catastrophic pipeline failures, the Joint Utilities are not aware of any established methodology that could be used to determine the release of methane and/or carbon dioxide (in the case of combustion). These types of events require specialized consideration and collaboration with various regulatory agencies to estimate the volume of emissions for potential inclusion in the greenhouse gas inventory for the State. On the other hand, for third-party damages that frequently occur, there are established engineering methods for calculating the total gas lost. Furthermore, these emissions are captured under the SB1371 report and have incremental BMPs that go beyond safety or integrity management programs that can help reduce emissions for these events.

As stated by the Scoping Memo and in Section 975(g) of SB 1371, the CPUC must "ensure that the rules and procedures it adopts are not inconsistent with the regulations and procedures adopted by those [state and federal entities that have regulatory roles of relevance in all aspects of the proceeding]."[11] The SB 1371 Rulemaking may need to consider how best to avoid duplication of the Division of Oil, Gas, & Geothermal Resources' (DOGGR) reporting and compliance requirements (as well as ARB's or other CPUC proceedings) related to underground storage wells. Otherwise, the scope of this proceeding may be significantly expanded in a way that may lose focus on SB 1371's purpose and requirements.

D. Add More Definitions of Terms, Consistent With Pipeline and Hazardous Materials Safety Administration (PHMSA), Where Applicable.

The Joint Utilities appreciate that SED recognized in its Revised Report Template that it is critical to distinguish between natural gas "leaks" (whether "graded" or "ungraded") and other "emissions" to be consistent with state and PHMSA's safety-related definitions and criteria, so that safety remains the top priority as directed by SB 1371. This ensures that hazardous or

[11] Scoping Memo, at 3; SB 1371 (Statutes 2014, Chapter 525), codified in CAL. PUB. UTIL. CODE § 975(g).

potentially hazardous leaks to persons or property remain the highest priority and are repaired first while still allowing Grade 3 leaks to be a focus for mitigation measures based on SB 1371's climate change goal (*e.g.*, a new repair timeline rather than monitoring) if system leaks are a top emission source for a gas corporation. The Revised Report Template's classification of other methane "emissions" that do not fall into the PHMSA definition of leaks as a separate category will avoid confusion or conflict with PHMSA's traditional definition of a leak.[12]

E. Improving the System-Wide Gas Leak Rate Calculation.

The Ruling states:

> The System-Wide Gas Leak Rate equation used in the May 15, 2015 Report was based on the PHMSA equation for Lost and Unaccounted For (LAUF) gas. However, CPUC and ARB staff determined that the equation was not an accurate indicator of gas being emitted and leaked from the system. From the equation, it was impossible to determine whether the volume of "lost" gas was actually being emitted and leaked, was the result of the measuring tolerances of the gas meters, or was the disappearance of the gas from the system. Therefore, staff recommends a System-Wide Gas Leak Rate equation, as shown in the Data Request, Attachment 2, and the Leak Rate tab in Appendix 8.[13]

The Joint Utilities previously recommended that gas corporations establish the "baseline system-wide leak rate"[14] required by SB 1371 utilizing an analysis of the top methane emission sources and estimating for each source the percentage of total emissions. SED's Revised System-Wide Gas Leak Rate formula incorporated the Joint Utilities' input, recognizing the inaccuracies associated with the previous SED formula attempting to calculate emissions as a percentage of throughput. As SED appropriately noted, with a throughput-based formula, "it

[12] It should be noted that parties have yet to comment on Scoping Question #1 regarding the leak definitions and scope of SB 1371: "As to questions of law, what does it mean under SB 1371 to be "consistent with" existing safety regulations and that "nothing in this article shall compromise or deprioritize safety as a top consideration?" Do any of the proposed changes to definitions or new requirements have an unintended consequence of deprioritizing safety?" Scoping Memo, at 6. Scoping Question #1 is scheduled for comments once SED issues its summary of the May 15, 2015 reports. The Joint Utilities reserve the right to comment on any proposed definitions and requirements under SB 1371, not just for reporting purposes, as well as whether they would deprioritize safety or otherwise be inconsistent with the statute's intent.

[13] Ruling, at 5-6.

[14] *See* SB 1371 (Statutes 2014, Chapter 525), codified in CAL. PUB. UTIL. CODE § 975 (e)(6).

was impossible to determine whether the volume of 'lost' gas was actually being emitted and leaked, was the result of the measuring tolerances of the gas meters, or was the disappearance of the gas from the system."[15] Due to the inherent system differences between each gas corporation, each will likely have different emitting sources. SED has recognized that by calculating the rate of methane emissions by emission sources on an annual basis, this will account for the dynamic nature of each utility's pipeline system, and evaluate these systems consistently.

As indicated in SoCalGas/SDG&E's October 27, 2015 workshop presentation,[16] the throughput has a small influence on overall emissions. There are few emission sources that can be directly correlated to throughput. If there is a need to compare performance between systems and/or set performance targets, the more appropriate method would be to develop performance metrics for each category of emission source and normalize the numbers. For example, the emissions from blowdowns are event-based and are driven by the level of activity related to pipeline integrity and safety enhancement programs or maintenance issues. Additionally, distribution system leaks correlate to the pipe material, not how much gas flows through the system (*e.g.*, leaks per 100 miles of unprotected steel main).

Therefore, for Appendix 8's "Leak Rate" tab, the Joint Utilities recommend several changes to reflect an asset-based inventory of estimated volume of emissions:

- the "Leak Rate (%)" column should be eliminated because, as recognized by SED, a throughput-based formula would not provide a suitable basis for comparison and could be potentially misleading; and
- the Transmission and Distribution Systems table should be separated into two

[15] Ruling, at 5.
[16] *See* October 29, 2015 Email Ruling Entering October 27, 2015 Workshop Materials into the Record and Seeking Comments on Refinement to the Annual Reporting Requirements and Cost Effectiveness Considerations.

tables and by asset inventory to align with the activity factor (AF) and emission factor (EF) categories and definitions in Appendix 9. System categories should include asset inventory factors such as miles of pipeline, number and type of compressors, number and type of M&R stations, etc.

F. Add Standardized Emission Factors.

The Ruling stated the following with respect to adding standardized Emission Factors (EFs) in Appendix 9:

> The May 15, 2015 reports contained gas emission volumes based on a wide variety of EFs. There was no consistent set of EFs used by all respondents. Consequently, it was impossible to compare gas leaks and emissions between the systems of the respondents or determine an accurate total amount of gas being emitted and leaked. In addition, the ARB noticed that some respondents were not using the most up-to-date EFs. As a result, the ARB conducted a series of meetings with the respondents to attempt to identify a consistent set of EFs that the ARB and the respondents could agree on. The meetings resulted in a set of EFs, however there was not agreement on all of the EFs. ARB continues to work with the utilities to arrive at mutually agreeable EFs that can be used in the May 15, 2016 report. The EFs in this ruling are considered a draft for the purpose of obtaining comments from the respondents. The draft EFs are found in Appendix 9, titled "Emission Factors."[17]

The Joint Utilities agree that EFs need to be consistent among the reporting gas corporations. Until new EFs are adopted in final form, operators should be using EFs that are consistent with current federal and state GHG reporting protocols under Subpart W and AB 32. This enables comparison among not only the California respondents, but also other gas corporations on a nationwide basis.

Additionally, the most up-to-date EFs are preferable so that the accuracy of estimates of emission volumes can improve over time. There needs to be an explicit process built into SB 1371's reporting process that allows for the incorporation of any updated or new EFs as they become available to ensure operators are reporting based on the most recent, peer-reviewed

[17] Ruling, at 5.

studies. As mentioned in previous comments,[18] the Joint Utilities believe it is important to create an avenue to review, and, if deemed appropriate, update these factors as new peer-reviewed research and findings are identified within the industry, and look forward to establishing this process with the ARB and the CPUC throughout Phase 1 of this proceeding. For example, the Environmental Protection Agency (EPA) is currently soliciting information from stakeholders across the nation on the appropriate EFs to use under federal air quality programs. The American Gas Association (AGA) recently provided their input into this process and the Joint Utilities concur with their recommendations.[19] There should be an informal review process before the issuance of SED's next annual Data Request (*e.g.*, in March 2017) to vet updated or new EFs with the respondents as they become available.

The Joint Parties are also concerned with the lack of explanation and rationale provided by ARB and SED regarding the election of certain EFs over others that were proposed by the utilities during the series of meetings described above in the Ruling. The utilities jointly developed recommendations of standardized EFs based on studies that were most appropriate for each system component and submitted them to ARB and SED on December 7, 2015. There is no explanation in the Ruling, Attachments, or Appendices as to why a particular factor was selected, particularly for those EFs that are different than those recommended by the utilities. For example, the EFs for Distribution Mains and Services in Appendix 9 are listed as "TBD following ARB GTI Contract." The utilities had jointly recommended that the Washington State University (WSU) study's EFs be used for buried distribution leaks in this category of emission sources, yet this was rejected without explanation. Moreover, there has been no opportunity for

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[18] *See* Joint Utilities' Comments on ALJ's October 13, 2015 Ruling Regarding Annual Reporting Requirements, at 5.

[19] *See* AGA's Comments on Revised Natural Gas Distribution Estimates Proposed for the Inventory of U.S. Greenhouse Gas Emissions and Sinks, dated January 14, 2016; Available at https://www.aga.org/sites/default/files/2016.01.14_aga_commentsepa_revisions_ghgi_final.pdf

public comment and peer review of ARB/GTI's study, but will apparently be incorporated into SED's Data Request to be issued on March 15, 2016. There should be a transparent process for vetting any studies to develop EFs adopted for use in SB 1371 reporting.

For emission sources not currently reported in AB 32 and Subpart W, there should be some coordination among all respondents to maintain some relative consistency for "engineering estimates" in Appendix 9. Otherwise, it would be difficult to reasonably compare emission sources that use engineering estimates across the various respondents.

III. JOINT UTILITIES' COMMENTS ON THE DRAFT 2016 DATA REQUEST AND DRAFT MAY 15TH REPORT TEMPLATE (ATTACHMENTS 2 AND 3)

The Draft 2016 Data Request's cover letter states: "If for any reason, you are unable to complete this request by this date, please provide a written explanation – by 5:00 pm on February 26, 2016 – why you cannot meet the response date and when you can provide the information."[20] The deadline of February 26th should be adjusted to March 26, 2016 to accommodate the Ruling's directive in OP 4 for SED to issue the data request with revised spreadsheet template to respondents by March 15, 2016. Otherwise, this would forgo any opportunity for a written explanation by the deadline if there is some need for clarification or an extension.

Section L of the Definitions in Attachment 2 defines "Graded Leaks" as "Gas leaks which are hazardous, or which could potentially become hazardous as described below," yet includes "Grade 3" non-hazardous leaks, which are by definition not hazardous and can be expected to remain so. This definition of "Graded Leaks" at the top of Section L should reflect that clarification to avoid confusion of Grade 3 leaks with the term "hazardous," which can inadvertently deprioritize safety criteria.

Attachment A provided below contains the Joint Utilities' suggested changes to the 9

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[20] Ruling, Attachment 2, at 2.

appendices in Attachment 3 of the Ruling.

IV. CONCLUSION

The Joint Utilities appreciate the opportunity to provide these joint comments and respectfully request that the Commission adopt the recommended changes to the Revised Report Template noted herein.

Respectfully submitted,[21]

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Dated: February 17, 2016

[21] As permitted by Rule 1.8(d), Counsel for SoCalGas and SDG&E has been authorized to sign the Joint Utilities' Comments on behalf of Southwest Gas.

ATTACHMENT A

Joint Utilities' Proposed Changes to the Annual Report Template Appendices

Appendix	Specific Reference	Joint Utilities' Proposed Change(s)	Joint Utilities' Explanation of Change(s)
Overall Comment on the Appendices: There are several instances where the reporting template requires that "Pressure (PSI)" be reported. In the comment box, it is clarified to mean MAOP= Maximum Allowable Operating Pressure; however, the Joint Utilities request that the comment box be edited to state MOP=Maximum Operating Pressure as MOP is applied for purposes of engineering estimates.			
Appendix 1 – Transmission Pipelines			
Tab "Pipeline Leaks"	• Column (E) – Pipe Age (Months) • Column (O) – Number Of Days Until Permanent Repair	• Column (E)- Delete	• Relevance of providing this data is unclear. The age of pipe has no implication for methane emissions calculations and is already provided in integrity management reporting. Providing such data could be misleading, such as inaccurate implication that age correlates to emissions, whereas pipe material bears more relevance. • Relevance of including this data is unclear and is duplicative since the reporting template already requests the scheduled date of the repair (Column L).
Tab "All Damages"	• Column (N)- Number Of Days Until Permanent Repair		• Relevance of including this data is unclear and is duplicative since the reporting template already requests the scheduled date of the repair (Column L).
Tab "Odorizers"	• Column (C)- Total Number	• Column (C)- Delete	• This field is irrelevant since odorizers have an ID column which is a unique identifier for each odorizer.
Appendix 2 – Transmission MR Stations			
Tab "Stations Leaks"	• Column (B)- Classification (Comment Box)		• Need to define the following items in the comment box: D = direct sale; T = transmission-to-transmissions interconnect
Appendix 3 – Transmission Compressor Stations			
Tab "Compressor Leaks"	• Column (D)- Prime Mover	• Column (D)- Delete	• Need to define Prime Mover and how this field is relevant for calculating methane emissions.
Appendix 4 – Distribution Main and Service Lines			
Tab "Pipeline Leaks"	• Column (E) – Pipe Schedule	• Column (E) – Delete	• Pipe Schedule has no relevance for calculating methane emissions.
Tab "All Damages"	• Column (C)- Damage Type (Comment Box Items: D = dig-in accident; N = natural disaster; A= accident) • Column (F) – Pipe Schedule • Column (G)- Pipe Size (inches)	• Column (C)- Damage Type (Comment Box: E=Excavation Damage; N=Natural Force Damage; O=Other Outside Force Damage) • Column (F) – Delete • Column (G)- Pipe Size (nominal)	• Modify this column to be consistent with the PHMSA definition of "Cause" of damage. • This has no relevance for calculating methane emissions. • Using nominal pipe size is consistent with industry standards. For example, a 2" nominal pipe has an actual outside diameter of 2.375."
Tab "Component Emissions"	• Column (D)- Manufacturer	• Column (D)- Delete	• The manufacturer is not relevant for the purposes of calculating methane emissions.
Tab "Odorizers"	• Column (C)- Total Number	• Column (C)- Delete	• This field is irrelevant since odorizers have an ID which is a unique identifier for each odorizer.
Appendix 6 – Customer Meters			
Tab "Blowdowns"	• Tab: Blowdowns • Column (A)- Number Of Blowdowns • Column (B)- Meter Type • Column (C)- Emission Factor (Mscf/yr) • Column (D)- Annual Emissions (Mscf)	• Rename the tab to "Vented Emission from MSAs" • Column (A)- Number Of Events • Column (B)- Activity Type • Column (C)- Engineering Estimate • Column (D)- Annual Emissions (Mscf/yr)	• Change this tab to "Vented Emission from MSAs" to align with the EFs.
Appendix 7 – Underground Storage			
Tab "Compressor Leaks"	• Column (D)- Prime Mover	• Column (D)- Delete	• Need to define Prime Mover and how this field is relevant for calculating methane emissions.
Tab "Blowdowns"	• Column (B)- Sources (Comment Box: W = wellhead rework; C = compressor)	• Column (B)- Sources (Comment Box: W = wellhead rework; C = compressor; P= Piping)	• In the comment box, the option to include "piping" should be included to be consistent with industry reporting.

ATTACHMENT A

Joint Utilities' Proposed Changes to the Annual Report Template Appendices

Appendix	Specific Reference	Joint Utilities' Proposed Change(s)	Joint Utilities' Explanation of Change(s)
Tab "Component Emissions"	• Column (C) – Type (Comment Box: C = connector; O = open-ended line; M = meter; P = pneumatic device; PR = pressure relief valve; V = valve)	• Column (C) – Type (Comment Box: C = connector; O = open-ended line; M = meter; PR = pressure relief valve; V = valve)	• Remove "P = pneumatic device" from the comment box as that item is not relevant.
Tab "Dehydrator Vents"	• Column (C)- Emission Factor (Mscf/yr)	• Column (C)- Delete	
Appendix 8 – Summary Tables			
Tab "Total Emissions"	• Column (D)- Total Annual Leaks & Emissions (Mscf) • Column (E)- Total System-Wide Annual Leaks & Emissions (Mscf) • Row 44, Columns (A)-(E) Unusual Catastrophic Events	• Column (D)-Total Volume of Methane Emissions (Mscf) • Column (E)- Delete • Row 44: Delete	• Rename this column and add a sum calculation to the bottom of Column D to represent the system-wide annual methane emissions in MTCO2e. • Delete this column and add a sum calculation to the bottom of Column D to represent the system-wide annual methane emissions in MTCO2e • Only those malfunctions of equipment and associated emissions that could have been reduced with BMPs beyond safety-related and integrity management programs should be included in the scope of SB 1371 reporting.
Tab "Leak Rate"	• Column (H) - Leak Rate (%) • Transmission and Distribution Systems (Tables)	• Column (H)- Delete • Transmission System (Table) • Distribution System (Table)	• Eliminate the "Leak Rate (%)" tab because, as recognized by SED, a throughput-based formula would not provide a suitable basis for comparison and could be potentially misleading. The tab titled "Total Emissions" already serves as a basis to compare emissions by source. • Transmission and Distribution Systems table should be separated into two tables and by asset inventory to align with the activity factor (AF) and emission factor (EF) categories and definitions in Appendix 9. System categories should include asset inventory factors such as miles of pipeline, number and type of compressors, number and type of M&R stations, etc.
Tab "NG Specification"	Overall Comments on Tab: • Purpose of this tab is unclear. For all the volumes being reported in the various tables, is the expectation to report volume of natural gas as opposed to volume of methane or CO2e?		
Appendix 9 – Emission Factors			
Tab "ARB Recommended Emission Factor"	Overall Comments on Tab: • Add a New Row in the "Underground Storage" System Category: Compressor station - Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters (using leak detection) • The EFs for Distribution Mains and Services in Appendix 9 are listed as "TBD following ARB GTI Contract." The utilities had jointly recommended that the Washington State University (WSU) study's EFs be used for buried distribution leaks in this category of emission sources, yet this was rejected without explanation. There has been no opportunity for public comment and peer review of ARB/GTI's study. • For emission sources not currently reported in AB 32 and Subpart W, there should be some coordination among all respondents to maintain some relative consistency for "engineering estimates" in Appendix 9. Otherwise, it would be difficult to reasonably compare emission sources that use engineering estimates across the various respondents. • Since internal systems have not been configured to capture the information required for calculating the emissions based on the recommended reporting methodology, SoCalGas and SDG&E will have to provide a rough estimate for purposes of the 2016 Report, reporting on 2015 data based on available data.		
	• Rows 14-15, Column (C): Engineering Estimate; Column (D), Rows 14-15: Emissions estimated from size of breach / pressure / duration calculation • Row 23: Storage-surface casing leakage • Column (C), Rows 42-44: GRI (1996) • Column (C), Rows 45-47: GRI (1996) • Column (C), Rows 50-51: GRI (1996)	• Column C = TCR; Column (D): EF (TCR) X Miles of Pipe /Year • Row 23: Delete • Column (C), Rows 42-44: MRR • Column (C), Rows 45-47: MRR • Column (C), Rows 50-51: MRR	• EF source should be TCR instead of an engineering estimate due to the fact that the overall emissions represent a nominal amount of the overall emission sources- it is not a top source emitter. • This item is not defined and no methodology is established for detection and estimation of emissions. • GRI EFs seem to significantly over-estimate emissions when compared with Subpart W results where actual survey data is used to estimate the emissions. Subpart W uses actual leak data x component EF on 20% of category facilities annually and accounts for the entire population as a running total over a 5-year period. The EFs used by component type are: Connector = 1.69 scfh/component; Block valve = 0.557 scfh/comp.; Control valve = 9.34 scfh/comp.; Pressure relief valve = 0.27 scfh/comp.; Orifice meter = 0.212 scfh/comp.; Regulator = 0.772 scfh/comp.; Open ended line = 26.131 scfh/comp