California Air Resources Board and California Public Utilities Commission Joint Staff Report

Analysis of the Utilities' June 17, 2016, Methane Leak and Emissions Reports Required by SB 1371

SB 1371 (Leno). Natural Gas: Leakage Abatement

R.15-01-008

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January, 2017

Executive Summary

On September 14, 2014, Governor Jerry Brown signed into law Senate Bill (SB) 1371, which requires gas corporations to report natural gas emissions from their facilities and summarize utility leak management practices, among other requirements.[1] In accordance with SB 1371, the California Air Resources Board (ARB) and California Public Utilities Commission (CPUC) prepared this report to analyze and account for natural gas emissions from leaks and vented emissions in the natural gas transmission, distribution and storage facilities in California.[2]

This is the second annual report in compliance with SB 1371 on natural gas emissions from utilities within the jurisdiction of the CPUC. The 2014 ARB and CPUC Joint Staff Report (the 2014 Joint Report) used 2014 data submitted by the utilities in May 2015 and was issued in February 2016. This Joint Staff Report (the 2015 Joint Report) uses 2015 data submitted by utilities on June 17, 2016, with additional data submitted in response to data requests from staff.[3]

On September 19, 2016, the Governor signed into law SB 1383 requiring "…the state board, the Public Utilities Commission, and the State Energy Resources Conservation and Development Commission to undertake various actions related to reducing short-lived climate pollutants in the state." SB 1383 directs ARB to "…approve and begin implementing the comprehensive short-lived climate pollutant strategy…to achieve a reduction in the statewide emissions of methane by 40 percent…below 2013 levels by 2030."[4] In addition, SB 32, which sets a 40% greenhouse gas reduction target for 2030, was passed and signed into law in 2016.[5] Both of these statutes build upon California's 2006 landmark policy, expressed in AB 32, for reducing greenhouse gas (GHG) emissions to 1990 levels by 2020.[6] This additional legislation directs ARB to develop plans to reduce statewide methane emissions. Although this legislation directs ARB to achieve certain methane and GHG reduction goals, neither statute has been explicitly scoped into a Phase 1 or Phase 2 of this proceeding.

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[1] PUC Code Section 975, Article 3 added by Stats. 2014, Ch. 525, Sec. 2. Effective January 1, 2015.

[2] Unless specified as a fugitive leak or vented emission, for the purposes of this report "emissions" include both fugitive leaks, and vented emissions of natural gas.

[3] R. 15-01-008, *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*

[4] *HSC - CHAPTER 4.2. Global Warming [39730 - 39731] (Chapter 4.2 added by Stats. 2014, Ch. 523, Sec. 1.) Sections 39730.5, 39730.6, 39730.7, and 39730.8.* https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1383

[5] California Global Warming Solutions Act of 2006: emissions limit. SB32, Pavley, Reg. Sess. 2015-2016. (2016).

[6] California Global Warming Solutions Act, AB32, Reg. Sess. 2005-2006 (2006)

This report provides the total estimated emissions from the gas storage and delivery systems and discusses emissions by system categories, by source categories and by leak grades.[7] This information should be used by gas system operators to help determine where emission reductions can be achieved to meet the State's methane emission reduction goal, while maintaining the safe and reliable operation of the regulated gas storage and delivery systems.

ARB's latest statewide GHG inventory, using 2014 data, reports California methane (CH_4) emissions in 2014 were about 39.8 million metric tons of carbon dioxide equivalent (MMTCO2e), using the 100-year global warming potential (GWP) of methane (see Table ES-1) from the Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Report (AR4), comprising approximately 9% of the State's total GHG emissions.[8]

Based on the utilities' latest reports, the total natural gas emissions estimate is 6,601.2 million standard cubic feet (MMscf) in 2015.[9] Using the IPCC global warming potential (GWP) value of 25 (AR4, 100-year methane GWP), this equates to approximately 2.96 million metric tons of carbon dioxide equivalent (MMTCO2e) emissions. Or using the IPCC GWP AR4, 20-year methane GWP value of 72 the 2015 emission estimate equates to 8.51 MMTCO2e. The CH_4 emissions from gas utility facilities in 2015 are about 7.5% of the statewide CH_4 emissions documented in 2014.

Table ES-1: SB 1371 Sector Emissions for 2015 (without Aliso Canyon):

Million Standard Cubic Feet (MMscf)	**6,601.2**
100-year GWP (x25) Million Metric Tons CO2e[10]	2.956
20-year GWP (x72) Million Metric Tons CO2e[11]	8.512

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[7] "System Category" refers to the grouping of assets by function within the natural gas delivery system. "Source Category" refers to grouping emissions based on like source, e.g. pipelines emissions, or M&R station emissions. See page 9 of this report for definition of leak grades.

[8] https://www.arb.ca.gov/cc/inventory/data/data.htm

[9] Note: This intentionally excludes the methane released from the 2015 Aliso Canyon storage failure because the extraordinary failure of the Aliso Canyon storage facility investigation and resultant regulations were handled outside this proceeding. The emissions from Aliso Canyon have been reviewed by ARB and the results are discussed in the Findings and Discussion section of this report.

[10] For purposes of this report we will use a GWP multiplier consistent with EPA and ARB which is 25 times the CO2e for methane. See calculation method in Appendix D.

[11] For comparison and context, we included the GWP consistent with ARB's methods that shows methane over a 20-year life cycle is 72 times more potent than CO_2. See calculation method in Appendix D. Regardless of which GWP is used, the relative ratios of methane emissions from various components of the gas system remain consistent.

One of the key findings of this report is that graded leak emissions make up 22% of all reported emissions in 2015. The majority of emissions, 78% of the total, come from ungraded leaks and vented emissions (Figure 6).[12] In the 2014 data, graded leaks only accounted for 11% of emissions and ungraded leaks and vented emissions accounted for 89% of reported emissions in the gas delivery system.

Table ES-2: SB 1371 2015 Emissions by System Category:

System Categories	Category Total MMscf	%
Transmission Pipelines	549.2	8.3%
Transmission M&R Stations	1,007.2	15.3%
Transmission Compressor Stations	162.7	2.5%
Distribution Main & Service Pipelines	1,702.9	25.8%
Distribution M&R Stations	1,348.1	20.4%
Customer Meters	1,638.3	24.8%
Underground Storage (without Aliso Canyon)	192.8	2.9%
	6,601.2	100.0%

CPUC and ARB Staff (Staff) attribute the differences between 2014 and 2015 graded and ungraded leak volumes to the changes in the data requested in 2015, such as the inclusion of the estimated graded leaks in un-surveyed areas, as well as requiring consistent application of conservative emissions factors (EFs) for 2015. Because of the changes in the data request, direct and detailed comparisons between 2014 and 2015 are not practical.

For both the 2014 and 2015 Joint Reports, the Distribution Mains and Services pipeline leak volumes make up virtually all graded leak volumes.[13] In the current report, the Distribution Mains and Services leaks comprise 99.6% of emissions from graded leaks and Transmission Mains and Services Leaks make up the remaining 0.4%. Grade 1 leak volumes comprise 25% of the total, Grade 2 about 16%, and Grade 3 the remaining 59.0% (Figure 4 and Table 3).[14]

[12] Vented emissions include operational blowdowns, automatic pressure relief valves, and other venting done for safety or operational reasons.

[13] In 2015 the transmission pipeline leak volumes are included but only make up 0.4% of graded leaks and 0.08% of total emissions. See Lessons Learned item number 7, page 32 below.

[14] Grade 1 leaks are leaks that represent an existing or probable hazard to persons or property and require prompt action. Grade 2 leaks are leaks that are not hazardous at the time of detection but justify a scheduled repair based on potential for a future hazard. Grade 3 leaks are leaks that are not hazardous at the time of detection and can reasonably be expected to remain non-hazardous.

For the 2015 Joint Report, utilities estimated the proportion of graded leaks that occur between surveys in the un-surveyed portions of their service territory based on the leak occurrence rate. As such, 46% of the graded leaks are estimated to exist in the un-surveyed areas (Figure 4 and Table 3) made up of approximately 660 MMscf, and this comprises 10% of the total emissions reported.

The ungraded leaks and vented emissions (78% of the total natural gas emissions) comprise the following system categories (Figure 2):

- Metering and Regulation (M&R) stations (both transmission and distribution) 35.7% of the total,
- Customer Meters 24.8%,
- Ungraded Pipeline emissions (both transmission and distribution) 11.9%,
- Compressor stations 2.5%, and
- Underground Storage facilities (excluding Alison Canyon) 2.9%.

Figure 6 shows emissions by activity category.[15] All blowdown and venting associated with operations and maintenance activities when grouped together account for 9.2% of emissions. Pipeline damages accounts for 4.8% of the total. Storage leaks and emissions (excluding the Aliso Canyon event) make up 0.8% and are combined with the ungraded leaks from M&R, Compressor, and Odorizer stations and their associated component leaks as well as Customer meter set assemblies (MSAs) that contribute 64.8% of the total natural gas emissions. This grouping highlights potential areas to focus on for improving practices, equipment or detection methods.

Conclusion:

The report describes a framework for understanding the data submitted in the June 17, 2016, reports and subsequent resubmittals. Some of the major findings are:

- The baseline emissions estimate for 2015 from SB 1371 sector utilities totals 6,601.2 MMscf, equal to 2.96 MMTCO2e using the AR4 100-year methane GWP or8.51 MMTCO2e using AR4 20-year methane GWP, which provides a starting point to measure future natural gas emission reductions.
- Significant changes to emission factors (EFs) could occur based on improved information. Staff would need to consider the implications of the change and potential need to adjust the baseline to avoid incorrect accounting. Nevertheless, the categories with the highest emission levels should be the

[15] For the Figure 6 chart the blowdowns and venting in each system category were grouped together, likewise pipeline damages were grouped together, and all ungraded leaks and emissions in the M&R, Compressor, and Odorizer stations.

starting point for establishing best practices to achieve the greatest amount of reductions for resources expended.

- The vast majority of ungraded emissions (64%, Figure 6) come from the components and equipment found throughout the delivery system. By parsing the emissions and identifying the volume of emissions and their sources, utilities can focus on the most cost-effective means to reduce emissions. By using actual emissions data, utilities should be able to address operating and maintenance practices, and component designs and materials to facilitate emission reductions.
- Among leaks that have been categorized as potential hazards, the grade 3 leaks make up a significant amount of leaks that are carried over year after year, making up 59% of the volume of all graded leaks. Even though grade 3 leaks are not considered a safety threat, cost-effective ways should be found to fix them sooner to reduce this persistent source of emissions.
- About 10% of the total emissions were from graded leaks in un-surveyed areas, estimated to occur between leak survey cycles. By reducing leak survey cycle times, the leaks occurring between cycles will emit for shorter lengths of time until they are detected and repaired. This effort should reduce emissions from graded leaks.
- Use of EFs may be acceptable in the short term for establishing the baseline emission levels. However, in order to better quantify emission reductions over time utilities must devise better ways to measure actual leak volumes. Relying on EFs may not fully account for emissions and reductions over time (e.g. every leak fixed is assumed to be emitting the same amount). Because it is difficult to quantify the actual volume of leaks and emissions, more work is needed to develop and improve California specific EFs until actual emissions measurements are available for the sources where it is feasible to directly measure emissions.
- Continuing refinement and improvement of the data reporting templates should increase transparency, and provide formats that consistently capture reliable leak and emission data for measuring changes in natural gas emissions.

Introduction

In accordance with Senate Bill (SB) 1371, the California Air Resources Board (ARB) and California Public Utilities Commission (CPUC) prepared this report to analyze and account for methane from leaks and vented emissions in the natural gas transmission, distribution and storage units in California.[16] On September 14, 2014, Governor Jerry Brown signed into law SB 1371, which required reporting and verification of emissions of greenhouse gases and also required gas corporations to file a report summarizing utility leak management practices, a list of new methane leaks by grade, a list of open leaks that are being monitored or are scheduled to be repaired, and a best estimate of gas loss due to leaks.

The report quantifies the emissions reported from the gas storage and delivery systems as well as shows those emissions by system categories, source categories and by grade. The information should be used by the gas system operators to help determine where emission reductions can be achieved while maintaining the safe and reliable operation of commission-regulated gas pipelines and other facilities. The metrics being used to compile this report should provide operators, the Commission, and the public with reasonably accurate information about the type, number, and severity of emissions and about the quantity of gas emitted to the atmosphere over time.

Additionally, on September 19, 2016, the Governor signed into law SB 1383 requiring "the state board, the Public Utilities Commission, and the State Energy Resources Conservation and Development Commission to undertake various actions related to reducing short-lived climate pollutants in the state." [17] The State Board (ARB) "shall approve and begin implementing the comprehensive short-lived climate pollutant strategy developed pursuant to Section 39730 to achieve a reduction in the statewide emissions of methane by 40 percent… below 2013 levels by 2030."

SB 1383 strengthens the work initiated by SB 1371 and focuses on the coordination between state and local agencies to develop measures for evaluating the progress of gas emission reductions. SB 1383 "… would require the state board *[Air Resources Board]*, no later than January 1, 2018, to approve and begin implementing that comprehensive strategy to reduce emissions of short-lived climate pollutants to achieve a reduction in methane by 40%, below 2013 levels by 2030. …"

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[16] Unless specified as a fugitive leak or vented emission, for the purposes of this report "emissions" include both fugitive leaks, and vented emissions of natural gas.

[17] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1383

In addition, SB 32, which sets a 40% greenhouse gas reduction target for 2030, was passed and signed into law in 2016.[18] Both of these statutes build upon California's 2006 landmark policy, expressed in AB 32, for reducing greenhouse gas (GHG) emissions to 1990 levels by 2020.[19] This additional legislation directs ARB to develop plans to reduce statewide methane emissions. Although this legislation directs ARB to achieve certain methane and GHG reduction goals, neither statute has been explicitly scoped into a Phase 1 or Phase 2 of this proceeding.

Background

According to the Intergovernmental Panel on Climate Change (IPCC) fourth Assessment Report (AR4), methane is 72 times more potent a greenhouse gas (GHG) than carbon dioxide (CO2) over a 20-year time frame. Although the more recent fifth Assessment Report (AR5) estimates a Global Warming Potential (GWP) multiplier as high as 86 times the impact of CO2 over a 20-year span, the AR4 values are used for consistency. ARB and EPA also use an alternate method for estimating methane emissions based on the AR4 for reporting GHG inventory levels that assumes an impact time frame over a 100-year span that results in a GWP factor of 25.[20] Many climate change researchers claim that using the 100-year time frame significantly understates the near-term impact of potent GHGs like methane. At this time, ARB uses the 100-year GWP for its official reporting of GHG inventories but uses the 20-year GWP for short lived climate pollutants such as methane. Both the 100-and 20-year GWP will be shown in this report.

ARB Staff analyzed sources of methane emissions as part of the annual Greenhouse Gas Inventory and the draft Short Lived Climate Pollutant (SLCP) Reduction Strategy. The chart below shows 2014 methane emissions from the transmission and distribution sector (i.e. pipelines) accounted for approximately 9% of total methane emissions in California. Using the 100-year methane GWP shown in the chart methane emissions are about 9% of the total GHG emissions in the state[21]; with methane emissions from the natural gas transmission and distribution systems making up 7.5% of 9%, or about 0.7% of California's total GHG emissions. Using the 20-year

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[18] California Global Warming Solutions Act of 2006: emissions limit. SB32, Pavley, Reg. Sess. 2015-2016. (2016).

[19] California Global Warming Solutions Act, AB32, Reg. Sess. 2005-2006 (2006).

[20] ARB used the AR4 100-year value of 25 times the CO2e for methane in its accounting for the 2000-2014 GHG inventories. See https://www.arb.ca.gov/cc/inventory/background/gwp.htm

[21] The 2014 GHG inventory shows 441.5 metric tons of CO2e and of that 39.8 metric tons of CO2e come from Methane or 9% of California's GHG in 2014 (39.8mtCO2e/441.5mtCO2e = 0.09 or 9%).

methane GWP increases the natural gas transmission and distribution systems contribution to statewide GHG to 1.7%.[22]

Purpose of the Gas Leak Abatement Report

This report provides a summary of the 2015 emissions inventory reports submitted by the utility companies on June 17, 2016. In order to meet the State's greenhouse gas reduction targets, California needs a current picture of methane leaks and emissions.[23]

The Administrative Law Judge (ALJ) ruling, *Entering Newly Revised Natural Gas Leak Annual Reporting Requirements into the Record and Seeking Comments,* issued on January 26, 2016, proposed using 2015 as the baseline year for natural gas emissions.[24] The CPUC received comments from the parties through February 24, 2016, and for the most part parties did not object to using 2015 as the baseline year. It is with this common understanding that the 2015 estimated methane leaks and emissions (sans extraordinary events such as Aliso Canyon) are at approximately the same level of emissions that occurred in 1990.[25]

Starting from this premise, the 2015 reported emissions provide a reasonable and reliable baseline to gauge reduction efforts going forward.

On April 12, 2016, the CPUC Staff issued a data request to all utilities in California to collect the information required by Article 3, Section 975 (c) and (e)(6). The data requests were developed to meet the requirements of Article 3, Section 975 (c) (1 through 4) and (e)(6). (See Appendix C for detailed wording.)

Pipeline leaks are categorized according to their "grade."

- Grade 1 leaks are leaks that represent an existing or probable hazard to persons or property and require prompt action.[26]
- Grade 2 leaks are leaks that are not hazardous at the time of detection but justify a scheduled repair based on potential for a future hazard.

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[22] Using the 20-year methane GWP increases the methane component of California GHG inventory to 113.7 MMTCO2e, added in place of the 39.8 MMTCO2e gives an estimated total of 515.4 MMTCO2e GHG for California. The natural gas transmission and distribution 20-year methane GWP of 8.512 MMTCO2e is 1.7% of 515.4 MMTCO2e.

[23] http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB 1371: SB 1371 refers to the AB 32 requirement to reduce California emissions to 1990 levels by 2020.

[24] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M157/K902/157902581.PDF

[25] California emissions of GHGs fell during the economic downturn from 2008 through 2012 and have not rebounded back to levels before the downturn.

[26] If a leak has not been graded but has been labeled Hazardous it will be included with the Grade 1 totals.

- Grade 3 leaks are leaks that are not hazardous at the time of detection and can reasonably be expected to remain non-hazardous.[27]
- Any remaining leaks are classified as ungraded leaks, such as leaks at customer meters and storage facilities.

Even though the system categories of emissions remained largely the same as those in 2014, a greater effort was made to standardize the data submissions to improve consistency and integrity of the data. To that end, the data request recommended the use of standard emissions factors (EFs) for this year's report.[28] The 2015 Joint Report covers emissions and leaks for associated components within system categories. Additionally, the report includes general discussions of changes to operational practices, new methods for leak and emission detection and mitigation programs. Lastly, improvements to data capture and methodology for estimating leaks and emissions may provide greater accuracy in future reporting cycles.

Basis for the Annual Gas Leak Abatement Report:

The data obtained for this report were provided by the natural gas operators including the large and small gas utilities (utilities), and independent storage providers (ISPs). The data were separated into seven system categories:

1. Transmission Pipelines (leaks, damages, blowdowns, components, and odorizers),
2. Transmission Metering and Regulation (M&R) stations (leaks, blowdowns, and components),
3. Compressor stations (compressor leaks and emissions, blowdowns, components, and storage tanks),
4. Distribution Pipeline Mains and Services (leaks, damages, blowdowns, and components),
5. Distribution M&R stations (leaks and emissions, and blowdowns),
6. Customer Meters (leaks, and venting), and
7. Underground Storage Facilities (leaks, compressors leaks and emissions, blowdowns, components, and dehydrators).

The respondents provided contextual information and explanations for their data to help understand the composition of the emissions, emission sources and related calculations underlying the emission estimates. The respondents summarized the data

[27] If a leak has not been graded but has been labeled Non-hazardous it will be included in Grade 3 totals.
[28] See Appendix 9 of the Data Request for specific EF's recommended by each System Category. http://www.cpuc.ca.gov/General.aspx?id=8829

and provided their system-wide leak information. See Appendix A for explanation of methods used to estimate emissions.

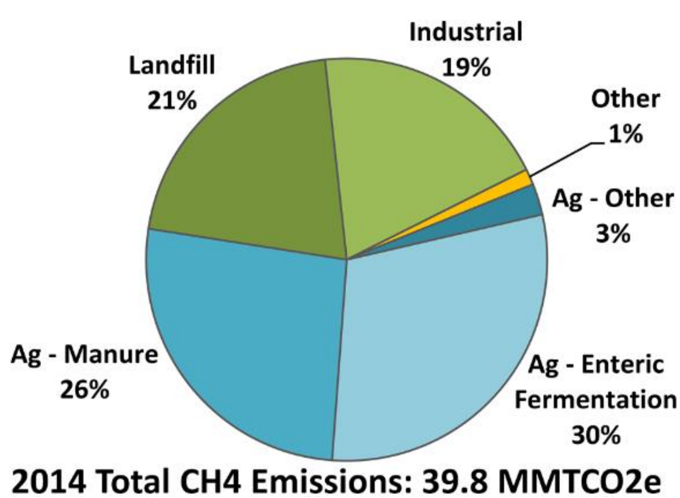
ARB and CPUC Staff worked together to prepare the templates used to report the data requested for the 2015 Joint Report. The templates were developed through working groups and feedback from parties on the data to be requested and how it should be structured in the template. The templates establish consistency in the data reporting and serve to highlight differences between data from different respondents.

ARB and CPUC Staff jointly analyzed the data for integrity and consistency. To complete the analysis, Staff requested supplementary information for clarification and submission of subsets of the data as issues were identified and corrected. Staff acquired insights and identified potential improvements through this process and noted opportunities for enhancements in future data requests in the "Lessons Learned" section of the report. Staff expects further evolution and improvement of emissions estimation methods going forward, as well as improved actual measurements.

Many of the improvements in the 2015 data request and emission estimating methods used render the 2014 data not directly comparable to the data collected in 2015. However, in the future it may be possible to apply improved estimation methods to previous year's estimates for like categories.

Findings and Discussion

Figure 1: The Latest Data on California Methane Emission Sources - 39.8 MMTCO2e Emissions in 2014:[29]



Ongoing Systemic Leaks and Emissions:

[29] https://www.arb.ca.gov/cc/inventory/background/ch4.htm

January, 2017

ARB's latest reported emission figures for 2014 (Figure 1) show that California is responsible for 441.5 million metric tons' carbon dioxide equivalent (MMTCO2e) GHG emissions.[30] Of this, the CH4 emissions comprise 9% or 39.8 MMTCO2e of California Statewide emissions. Staff does not have 2015 statewide total GHG data at this time, but assume 2015 emissions are roughly consistent with 2014.

The 2015 estimated natural gas emissions of 6,601.2 MMscf, which equates to 2.96 MMTCO2e emissions (AR4, 100-year methane life cycle) represent 0.67% of 2014 statewide GHG emissions and 7.5% of 2014 methane emissions.[31]

Methane is recognized as a very potent GHG, which has an impact many times greater than carbon dioxide (CO2). Using AR4's 20-year methane life cycle for the 2015 emission estimate would equate to 8.51 MMTCO2e.

ARB's SLCP reduction strategy concludes that California can reduce its methane emissions by 40 percent below current levels through a collaborative and mixed approach that combines incentives, public and private investment, and regulation.[32]

The 2015 reported emissions totaled 6,601.2 MMscf, whereas the 2014 reported emissions totaled 3,880.7 MMscf. Though this initially might lead one to believe a 70% increase in natural gas emissions took place year over year, the difference can be partially explained by changes made as a result of changes to 2015's data request resulting from lessons learned from the 2014 report. There are several reasons why the 2015 data are not comparable to 2014 data:

1) The 2014 Distribution Mains and Services pipeline leaks included all detected leaks including above ground leaks that may have been associated with customer meter set assemblies (MSAs). The 2015 data excluded any above ground leak considered to be part of the MSA.
2) Because pipeline leak surveys are done on multi-year cycles, for 2015 pipeline operators made a significant effort to estimate the leaking potential from the leaks that occur between surveys in un-surveyed territory.
3) The 2015 templates recommended specific EFs to ensure consistency between operator data; whereas in 2014 operators were allowed greater latitude in the EFs each could use and justify.
4) Greater rigor was imposed on the calculation of emissions from blowdowns, components and equipment.

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[30] https://www.arb.ca.gov/cc/inventory/data/data.htm

[31] Total Natural Gas emissions reported to the CPUC/ARB for the 2015 annual report without Aliso Canyon come to 6,601.2MMscf which translates to 118,228 metric tons of methane. See Appendix D for calculations.

[32] https://www.arb.ca.gov/cc/shortlived/shortlived.htm

5) The categorization in the 2015 data templates differs significantly from 2014's. As a result, comparing 2015 reported data to 2014 may result in misleading or invalid conclusions about the trend or changes in emissions.

Aliso Canyon Storage Facility:

Beginning in October 2015 and lasting through February 2016, operators of the Aliso Canyon gas storage facility in Southern California reported an uncontrolled leak preliminarily attributed to the failure of well pipe casing below ground level. The root cause analysis is still ongoing. Based on ARB analysis, the Aliso Canyon leak event contributed about 5% to California's State wide natural gas emissions in 2015.[33] The ARB study used various measurement and quantification methods to evaluate the range of estimates that converged around a total quantity of 99,650 metric tons of methane emissions for the duration of the leak.[34]

The duration of the event and difficulty to contain the large storage leak raised the national awareness of the risks associated with natural gas storage facilities. Consequently, this large leak resulted in new storage facility regulations and a new awareness of the significant impact that storage facilities have on California electric generation and consumers of natural gas in southern California. The environmental risks from this single leak were substantial and the safety, operations and maintenance regulations are still under examination.

For purposes of this report, Staff focused on the leaks and emissions from ongoing operations. The catastrophic nature of Aliso Canyon emissions will be discussed in context, but they are largely outside the scope of this report and the efforts to reduce systemic emissions in this sector.

Key Findings:

A key finding from 2015 data is that although the graded leaks are significant, the ungraded leaks and associated emissions make up the largest subset of emissions reported. The ungraded leaks and vented emissions comprised 3.5 times the amount as the graded leaks at 78% of the total system emissions from the gas delivery system (Shown in Table 2).

In 2014, Staff reported that graded leaks were about 11% of the emission volume and ungraded leaks and emissions were approximately 89%. In 2015, the magnitude of

[33] The 78,895 MT of CH_4 equated to 1.97 MM MT CO_2e or 4.7% of estimated 2015 CH_4 emissions assuming 2014 and 2015 CH_4 overall emissions would be the same. Calculated emissions based on ARB report page 25 data. https://www.arb.ca.gov/research/aliso_canyon/aliso_canyon_methane_emissions-arb_final.pdf

[34] Ibid, Pg.1.

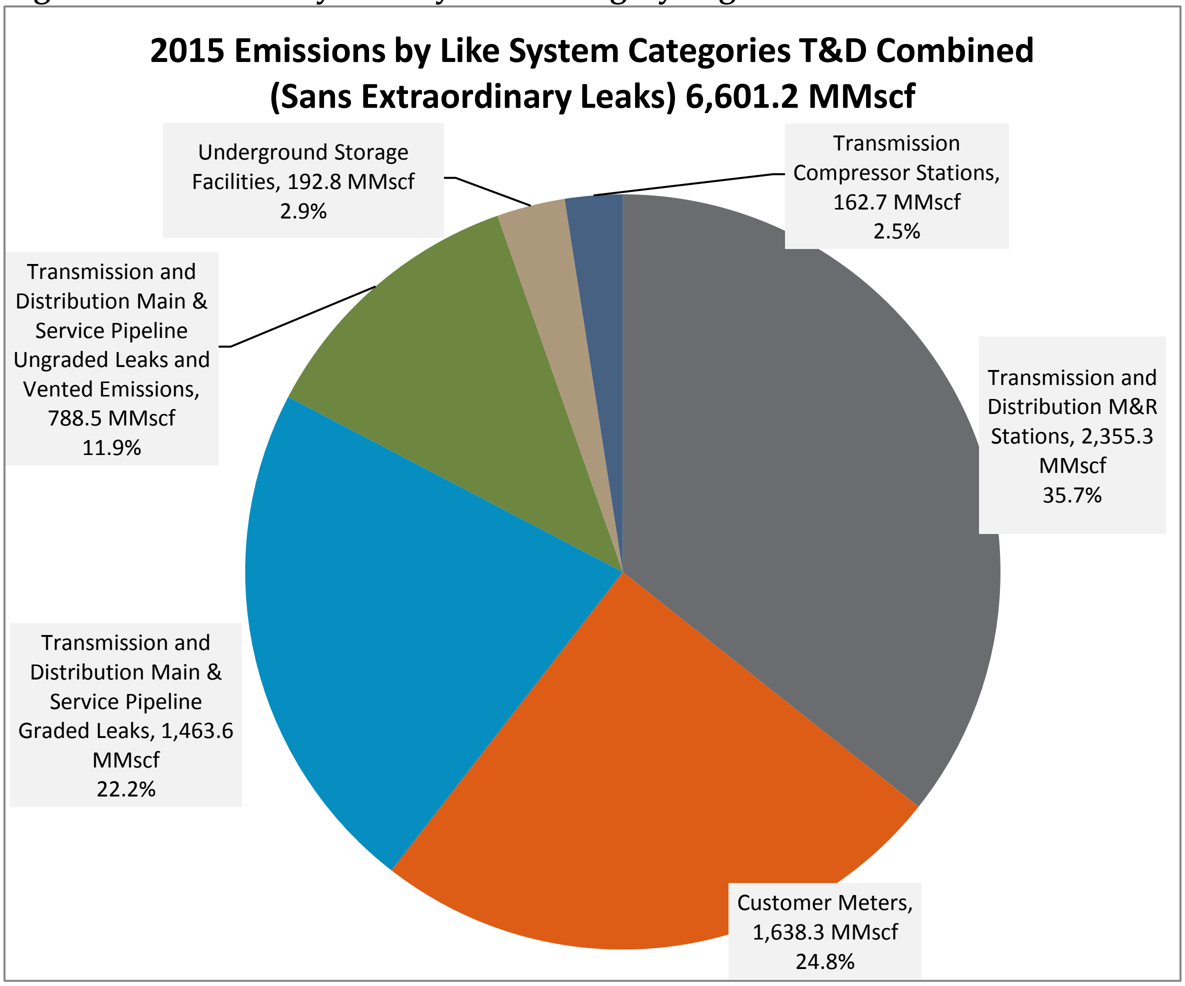
the difference appears to be significantly less, which Staff attribute to several changes to the data provided year over year as noted above.

The graded leaks volume makes up 22% and almost exclusively represents Distribution pipeline leak volumes.[35] As noted in the prior section, the changes in the data request make detailed comparisons between 2014 and 2015 difficult. The ungraded leaks and vented emissions that make up the remaining 78% of the total (see Figure 2) are listed below by system category:

1. M&R stations (both transmission 15.3% and distribution 20.4% combined), 35.7%,
2. Customer meter set assemblies (MSAs), 24.8%,
3. Ungraded leaks and vented emissions in the combined Transmission (8.2%) and Distribution (3.7%) pipeline systems, 11.9% (omitting the 22.2% for graded leaks),
4. Compressor stations, 2.5%, and
5. Underground Storage facilities (sans Alison Canyon) 2.9%.

[35] Transmission pipeline leak volumes are included but only make up 0.04%.

Figure 2: Emissions by Like Systems Category (e.g. All M&R stations.):[36]



In Figure 2, both the Transmission and Distribution Pipelines data were combined, graded leaks were combined and the remaining emissions from the pipeline system categories were also combined to differentiate the emissions from pipeline components, damages, and other sources other than pipeline graded leaks.

The potential for mitigation of emissions from facilities and components becomes apparent because it comprises nearly two thirds of the sector emissions. Venting and blowdown emissions are approximately 9% of the total, and though this is significant, it by itself would not provide enough reduction opportunity to achieve the reduction goals needed to meet the levels required by SB 1371 and SB 1383.

Additionally, by separating out and combining the emissions by the source activity, such as all blowdowns together, or station facilities, or compressors no matter

[36] For this chart the compressors from underground storage, compressor stations and their related components were grouped together. The underground storage facility emissions represent the grouping of the underground storage facility, components and dehydrators. Any venting or blowdowns from all facilities were grouped into the Blowdown and Venting total.

where located, it is easier to see emissions from like activities and systems. This is discussed further and shown in Figure 6 later in the report.

Global Warming Potential – Putting the Emissions into Context:

Table 1 shows the total emissions reported (excluding the Aliso Canyon Storage leak) for ungraded leaks and vented emissions, and pipeline graded leaks in MMscf of natural gas, metric tons of CH_4 as well as for both the 100- and 20-year GWP values.

Table 1: The Global Warming Potential in Various Equivalent Metrics:[37]

	MMscf	Metric Tons CH4	100 Year GWP MMTCO2e	20 Year GWP MMTCO2e
Ungraded Leaks and Vented Emissions	5,137.5	92,013	2.300	6.625
Pipeline Graded Leaks	1,463.6	26,214	0.655	1.887
2015 Total Emissions	**6,601.2**	**118,226**	**2.955**	**8.512**

The total emissions equate to 285,000 trips driven around the world at the equator, which would burn about 332.6 million gallons of gasoline.[38] See Appendix D for details on how the GWP was calculated.

Emissions by System Category:

As required by SB 1371, each utility company was asked to provide information for the seven appendices: (1) Transmission Pipelines, (2) Transmission M&R Stations, (3) Transmission Compressor Stations (4) Distribution Mains and Services Pipelines, (5) Distribution M&R Stations, (6) Customer Meters, and (7) Underground Storage.

All ten natural gas utilities jurisdictional to the CPUC responded to the data request. Each utility reported emissions from more than one appendix. This report will avoid identifying individual companies' data responses, but will report data in aggregate. The companies will collectively be identified as "utilities." The findings for each appendix are discussed following the Figure 3.

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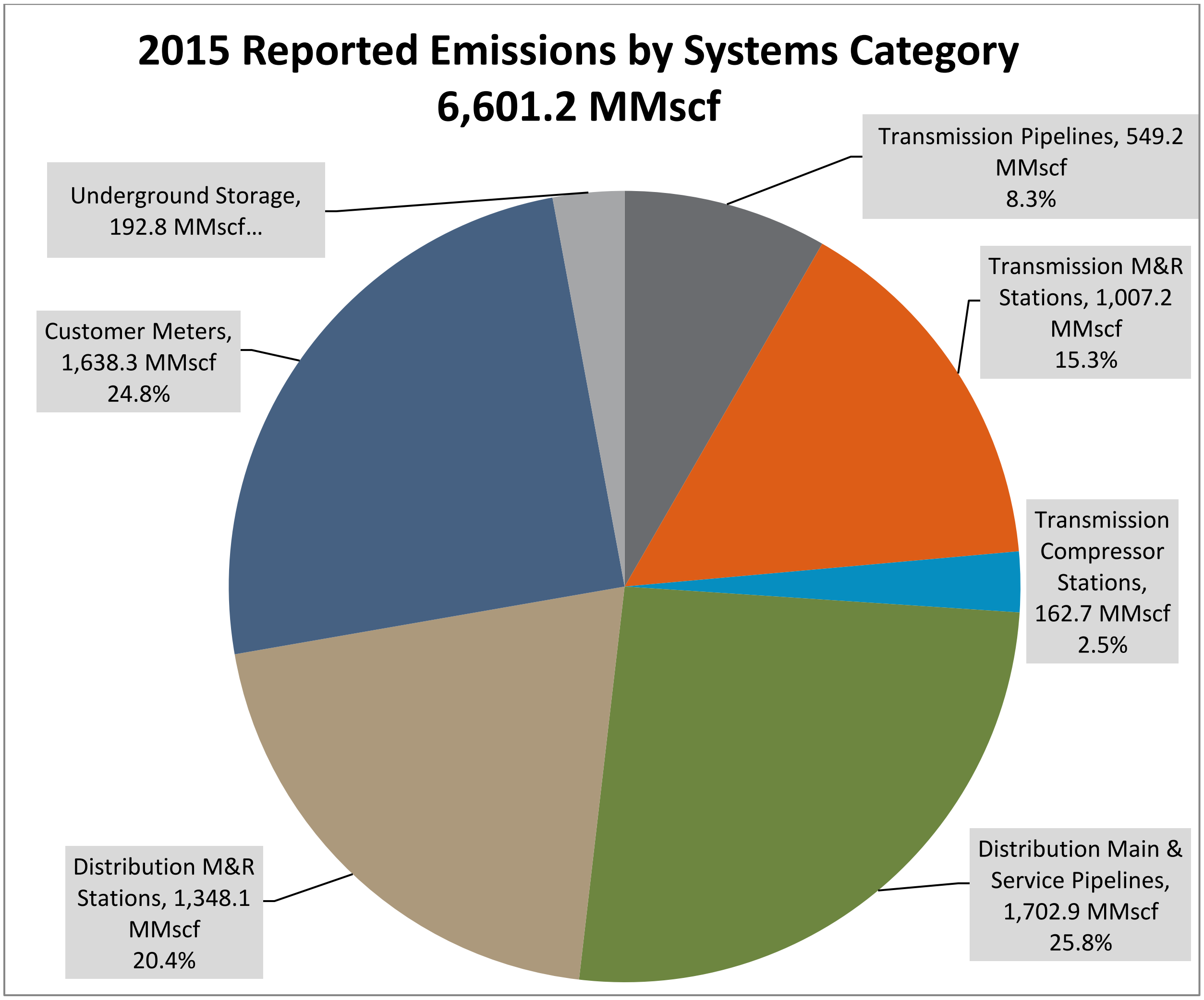
[37] EPA GHG equivalency calculator derived amounts (https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator) using a 100-year GWP multiplier of 25.

[38] EPA's GHG calculator shows that 118,226 mtCO2e equates to 332.6mm gallons of gasoline, or 7,083mm miles driven by the average car. Dividing the 7,083mm miles by the circumference of the earth at the equator (24,901miles) the result is 284,474 trips around the globe. https://www.arb.ca.gov/cc/inventory/slcp/slcp.htm

Figure 3: Reported Emissions by System Category:[39]



Transmission Pipeline

Four utilities reported a total of transmission pipeline emissions of 549 MMscf or 8% of the total. The major contributor to emissions in this category comes from blowdowns of approximately 455 MMscf of natural gas; while pipeline leaks only approximated 5 MMscf. Damages from third parties came to 82 MMscf, associated components emitted 5 MMscf, and odorizers emitted 3 MMscf. Transmission pipeline survey cycles vary from one to five years depending on the type, location and condition of the pipeline.

[39] Each system category includes all the associated leaks and vented emissions from its related infrastructure, such as leaks, component leaks, vented emissions and damages.

Transmission M&R Stations

Four utilities reported total transmission M&R stations emissions of 1,007 MMscf or 15% of the total. This category includes farm taps, transmission inter-connects and intra-connects. The emissions from M&R stations leaks approximated 942 MMscf, blowdowns were 66 MMscf, and associated components added 0.02 MMscf.

Transmission Compressor Stations

Three utilities reported total transmission compressor stations emissions of 163 MMscf or 3% of the total. The majority of emissions of 106 MMscf came from the compressors, blowdowns were 31 MMscf and leaks from associated components were 25 MMscf. The storage tank leaks and emissions amounted to 0.003 MMscf.

Distribution Mains and Services

Six utilities reported total distribution mains and services emissions totaling 1,703 MMscf or 26% of total emissions. This asset category comprised the single largest system category of natural gas emissions. The smaller utilities perform leak surveys annually, whereas the larger utilities perform leak surveys of their service territory over multiple years[40]. After the initial data reports were submitted, Staff discussed the data submissions with utilities and found differences in methods used to estimate leaks in un-surveyed portions of utility territory. The CPUC and ARB worked with utilities to standardize the methodology of calculating emissions from un-surveyed mains and services.[41] The methodology will be reviewed in future workshops and memorialized in future data requests.

Distribution mains and services pipeline graded leaks came to 1,458 MMscf, damages by third parties accounted for 236 MMscf, blowdowns at 5 MMscf and associated component emissions came to 3 MMscf.

[40] The utilities perform periodic surveys with different cycles depending on the type of infrastructure, statutory requirements and regulations and operating practices. Cycles of one, three and five years are common.

[41] The basic approach used takes the leak occurrence rate and estimates the leaks that occur in the sections of service territory since the last survey. For example, if the survey cycle is three years and the leak occurrence rate is 3, then the expectation is that in the section of territory surveyed in the prior year 33% the number of leaks occurred, and in the section surveyed two years' prior 67% the number of leaks occurred. So, these added together would net 100% or a factor of 1 times the number of leaks occurring added to the leaks found in the year of interest to estimate the system leaks.

Distribution M&R Stations

Four utilities reported total distribution M&R station emissions of 1,348 MMscf or 20% of total reported emissions. The M&R station blowdowns were quite small at 0.3 MMscf.

Customer Meters

Six utilities reported emissions from MSAs totaling 1,636 MMscf, which is virtually this entire system category's total of 1,638 MMscf or about 25% of total emissions. The emissions from MSAs are based on EFs applied to the population of customer meters. The venting associated with MSAs was estimated at 2 MMscf. MSA emissions are the second largest source of emissions.

Underground Storage

Six utilities reported underground storage systems emissions totaling 193 MMscf or 3% of the total (sans Aliso Canyon). The emissions from compressors used in this system category constituted the largest source of emissions at 96 MMscf, the associated storage facility leaks come to 15 MMscf, the blowdowns in this category are 46 MMscf, the dehydrators emit 20 MMscf, and other associated components emit the remaining 15 MMscf.

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Table 2: Emissions Details by Category

System Categories	Category Total	%	Emission Source Categories SOURCE	Volume	%
Transmission Pipelines	**549,248**	**8.3%**	**Pipeline Leaks**	**5,237.6**	0.1%
			All Damages	**81,793.0**	1.2%
			Blowdowns	**455,055.5**	6.9%
			Component Emissions	**4,591.8**	0.1%
			Odorizers	**2,570.4**	0.0%
Transmission M&R Stations	**1,007,226**	**15.3%**	**Station Leaks & Emissions**	**941,622.0**	14.3%
			Blowdowns	**65,582.5**	1.0%
			Component Leaks & Emissions	**21.0**	0.0%
Transmission Compressor Stations	**162,686**	**2.5%**	**Compressor Emissions**	**106,257.2**	1.6%
			Blowdowns	**31,087.7**	0.5%
			Component Leaks & Emissions	**25,338.3**	0.4%
			Storage Tank Leaks & Emissions	**3.3**	0.0%
Distribution Main & Service Pipelines	**1,702,871**	**25.8%**	**Pipeline Leaks**	**1,458,398.6**	22.1%
			All Damages	**236,145.2**	3.6%
			Blowdowns	**5,045.6**	0.1%
			Component Emissions	**3,281.2**	0.0%
Distribution M&R Stations	**1,348,067**	**20.4%**	**Station Leaks & Emissions**	**1,347,772.5**	20.4%
			Blowdowns	**294.9**	0.0%
			Component Leaks & Emissions	**-**	0.0%
Customer Meters	**1,638,274**	**24.8%**	**Meter Leaks**	**1,635,910.4**	24.8%
			Vented Emissions	**2,363.4**	0.0%
Underground Storage	**192,797**	**2.9%**	**Storage Leaks & Emissions**	**15,016.4**	0.2%
			Compressor Emissions	**96,313.1**	1.5%
			Blowdowns	**46,358.0**	0.7%
			Component Leaks & Emissions	**14,946.6**	0.2%
			Dehydrator Vent Emissions	**20,162.9**	0.3%
	6,601,169	**100%**		6,601,169.0	100.0%

Specific Data Request Information

As required by SB 1371, each utility company was asked to provide information on the following activities: (1) leak management practices, (2) new methane leaks by grade, (3) open leaks that are being monitored or are scheduled to be repaired, (4) a best estimate of gas loss due to leaks and (5) a baseline system-wide leak rate.

Ten natural gas utilities submitted responses to the data request of which transport, distribute and/or provide natural gas storage services.

(1) Leak Management Practices:

Operator Changes to Identify, Report and Reduce Emissions – Question 1:

Each utility has a policy and an inspection plan to investigate leaks. All the California gas companies participating in this initiative utilize standard industry practices for leak detection and repair. Utilities also noted using novel practices and newer technologies. Some examples of different practices include the use of mobile mounted methane technology to assist in leak detection, while other utilities conduct walking gas leak surveys of their pipeline infrastructure, and some survey their right-of-way using flame ionization leak detection devices. Most operators utilize a combination of equipment, including flame ionization, remote methane leak detection, and amplified catalytic sensor devices, to search for the presence of natural gas leaks. One operator also utilizes the newer infrared based leak detection survey instruments process, as well as the standard hydrogen flame ionization detectors.

The gas utilities started examining and evolving practices and procedures for safety reasons prior to 2014 and the use of new leak detection technologies resulted in a significant increase in leaks detected and graded.

Utility operators expanded their use of technology to detect ambient leaks in their systems, though in varying degrees and types of technology. The use of mobile detection equipment increased and in one case there was a two-fold increase in distribution services surveyed in 2015 from 2014, and in 2015 operators expanded the use of analytical tools that focus on customer usage variables associated with the increased potential for leaks.

Automated use of database analytics, which detect unusual or aberrant gas consumption patterns, may provide a method for early detection that could significantly reduce the duration of a large leak. In addition, operators continued to evaluate and fund research on mobile leak quantification technologies (e.g. Picarro, Washington State University, Colorado State University, and other collaborative projects).

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Operators implemented the U.S. Environmental Protection Agency's (EPA) new Mandatory Reporting Requirements (MRR), which lowered the volume threshold for reporting blowdown events to those with volume of 50 cubic feet or greater. Related to operations and maintenance, where feasible, operators focused their efforts to reduce pipeline pressures prior maintenance procedures that reduce the volumes subject to venting or blowdown. In some cases, operators employed analytics to identify business districts that should be surveyed more frequently, in these cases higher risk areas are being surveyed more frequently with the potential for reduced safety risks as well as quicker identification and mitigation of leaks.

Due to the increased focus on best practices operators have unilaterally begun networking with experts across the nation to find better maintenance and mitigation procedures as well as share their own successes and experience with leak detection and mitigation. One operator reported voluntarily adopting EPA Gas STAR Rod Packing Replacement that is intended to reduce natural gas leakage from rod packings.

Additionally, the operator worked on improving operating procedures and simulated Emergency Shutdown (ESD) procedures to train operators and increase awareness and preparedness for ESD events. In other cases, where operation practices and human factors lead to inadvertent or excessive emissions in the past, utilities focused on changing procedures and increasing training over proper O&M procedures. In addition, third-party owned leak-prone compressors were removed and replaced with equipment less prone to emissions.

Lastly, operators continue to replace distribution mains and service pipeline in accordance with their operations and maintenance plans approved through the general rate cases that fund capital and maintenance investments.

Summary of Proposed Changes to Management Practices – Data Request Question 7.a:

The utilities' 2016 reports show a significant amount of changes to practices, equipment and research. The following brief summary of the intended and proposed changes to management and operating practices shows the potential for significant impact on natural gas emission reductions.

The summary includes the most significant changes outlined by respondents in their annual report filing. Many of the changes indicated a need for funding in order to undertake the proposed practice, or expand it beyond the pilot or research stage. The funding mechanisms and focus on what may be incremental funding for what many might characterize as the normal evolution of business and operating best practices is beyond the scope of this report. Therefore, Staff excludes any reference to funding and focus only on the practice changes listed by respondents.

The items listed were noted by one or more of the utilities. Staff tried to include representative and significant changes in this list and does not include every proposed or initiated change reported by respondents.

1) Refine EFs to improve quantification of leaks and emissions on a granular equipment and component level that is below the macro facility EFs currently used for Customer Meter Set Assemblies, Direct Sale Meter Sets, M&R Stations, and Farm Taps. The current EFs are suspected of understating emissions, moreover, granular component specific EFs should improve quantification efforts and the studies should identify the leakiest components for targeting for reduction opportunities.
2) Reduce hazardous and non-hazardous leak inventories through shortened repair time protocols, and shortened survey cycles.
3) Identify pipeline segments most in need of replacement through GIS tools that facilitate prioritization and optimization of pipeline replacement programs by identifying leak clusters.
4) Increase the amount of annual distribution pipe replaced, focusing on pre-1940 steel and pre-1985 Aldyl-A pipe.
5) Increase commitment and participation in EPA's Methane Challenge to adopted best practices. Areas of impact include but may not be limited to: Excavation damages best management practice (BMP) through the Gold shovel program, and blowdown reductions through re-routing natural gas and flaring.
6) Continue research, evaluation and improvement of Mobile Methane Mapping Assessment of pipeline emissions to identify and prioritize pipeline for replacement results in emissions reductions.
7) Evaluate and Change O&M practices on compressors, e.g. to perform compressor rod packing replacements on more frequent operational intervals, and to evaluate compressor operating procedures that lead to reduced blowdowns during start up.
8) Change or replace high or intermittent bleed pneumatic devices with technology that vents less natural gas.
9) Improve data collection of blowdown activities that support better operational practices. Improve the type and breadth of data collected that may be used to examine current practices in order to streamline the information capture of blowdown and operational activities.

10) Adopt technologies that will allow the electronic tracking of verified gas leaks to facilitate electronic record keeping, with the potential to evolve into automated field readings updates, and provide mapping tools that overlays survey routes on existing infrastructure.
11) Implement site inspections per new Department of Geothermal, Gas and Oil (DOGGR) and ARB rules affecting Storage facilities. In addition, some utilities are going further by proactively identify and mitigate potential storage well safety and/or integrity issues to enhance their existing maintenance and prevention programs.
12) Conduct various research projects to advance the science and tools available to detect and quickly quantify leaks. For example, projects included fast accurate low detection level portable handheld instruments, leak survey tracking, and drone technology for detection and assessments.

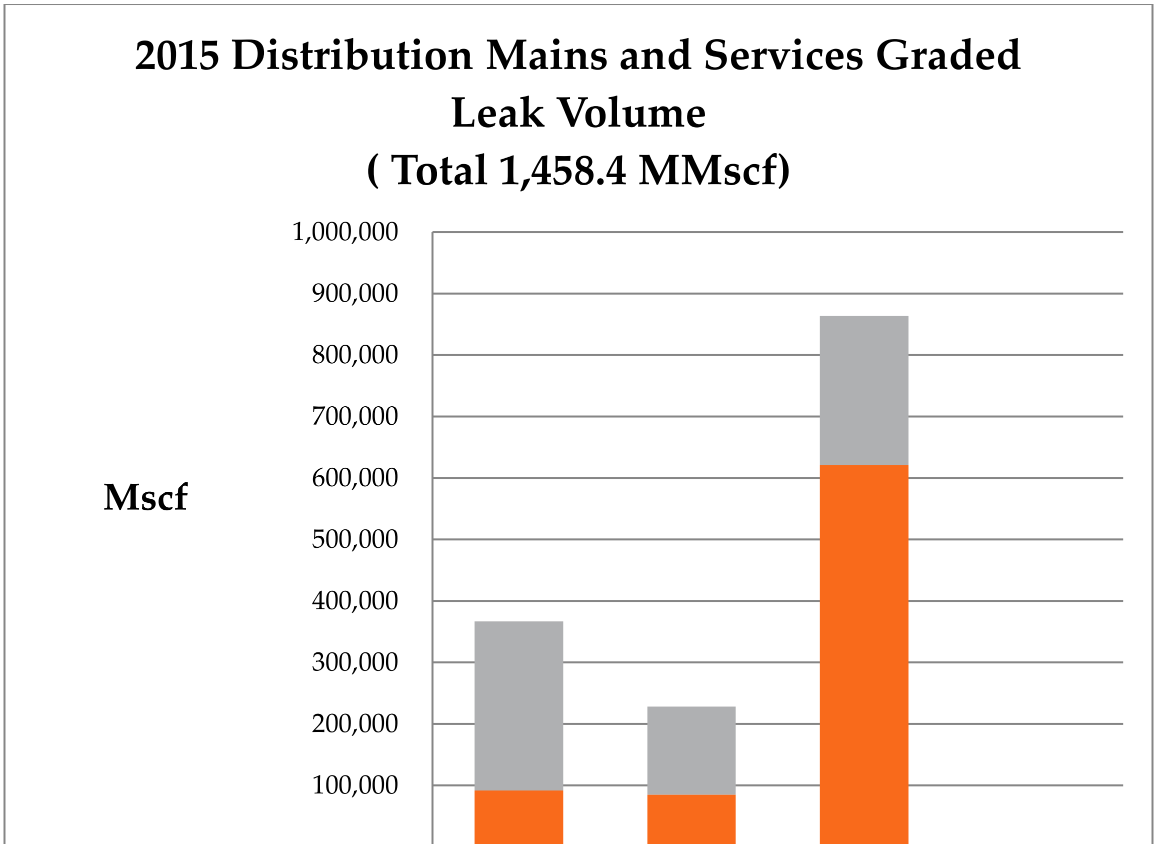
(2) New Methane Leaks in 2015 by Grade:

All utility companies listed the number of methane leaks discovered in 2015. They provided detailed information for such leaks including: the grade type, emission source, pipe size, date discovered, date repaired. The size of the leak volume was estimated using EFs provided in the data request that were primarily based on the 1996 GRI study.[42] A graph of leak volumes by grade in 2015 is shown in Figure 4 with corresponding proportions shown as percentages in Table 3. The grade 3 leaks that go unrepaired comprise the largest volume of leaks. There also could be a safety co-benefit from more frequent survey cycles by finding and fixing grade 1 leaks sooner. The leak counts by grade are found in Figure 5 with corresponding proportions shown as percentages in Table 4.

There is a significant volume of estimated leaks in the un-surveyed areas of the Distribution system that if detected sooner by employing shorter survey cycles (e.g. from a 5-year to 3-rotation) could provide an immediate one-time reduction from detecting and repairing leaks sooner. This assumes the leak rate will not change in the near future so that once the leak repairs reach a new equilibrium; leaks will occur at basically the same rate over time and get fixed within the new survey cycle timeline.

[42] http://www.cpuc.ca.gov/General.aspx?id=8829.

Figure 4: Distribution Mains and Services Graded Leaks:



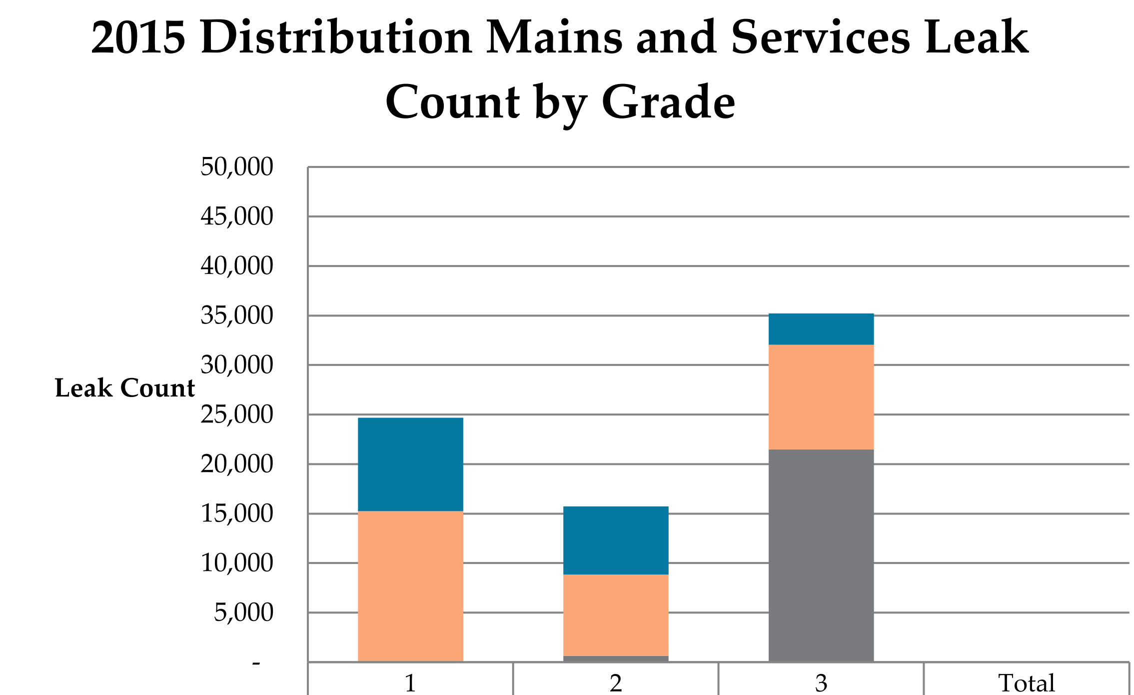
	1	2	3	Total
Estimated Emissions from Un-Surveyed Territory	274,956	143,081	242,456	660,493
Emissions from Open Leaks	91,580	84,977	621,349	797,906
Total	366,536	228,058	863,805	1,458,399

Note: The leak volume includes the estimated leaks in the un-surveyed portion of operator's service territories based on the leak occurrence rate by grade. Staff took the proportion of leaks discovered in 2015 during surveys and applied that ratio to the leaks estimated in the un-surveyed areas.

Table 3: Distribution Mains and Services Contribution to Leak Volume Percentages by Grade:

Grade	1	2	3	Total
Estimated Emissions in Un-Surveyed Territory	19%	10%	17%	45%
Emissions from Open Leaks	6%	6%	43%	55%
Total	**25%**	**16%**	**59%**	**100%**

Figure 5: Distribution Mains and Services Leak Counts by Grade:[43]



	1	2	3	Total
Leaks Repaired in 2015	9,450	6,902	3,139	19,491
Estimated Leaks in Un-Surveyed Territory	15,220	8,190	10,578	33,987
Open Leaks at 12/31/15 Carryover to 2016	25	648	21,483	22,156
Total	24,695	15,740	35,200	75,634

Table 4: Distribution Mains and Services Leak Count by Grade Percentages:

Grade	1	2	3	Total
Leaks Repaired in 2015	12%	9%	4%	26%
Estimated Leaks in Un-Surveyed Territory	20%	11%	14%	45%
Open Leaks at 12/31/15 Carryover to 2016	0%	1%	28%	29%
Total	**33%**	**21%**	**47%**	100%

[43] These counts do not include above ground leaks because the emissions are included in the customer MSA emissions mixing in the count of leaks in these charts would distort the count and emissions comparisons.

In the 2014 Joint Report, one of the notable findings was that ungraded leaks and vented emissions made up the majority of emissions, and this holds true for 2015 but to a lesser extent. However, the fact that a majority of emissions still comes from ungraded leaks and vented emissions supports the continued focus on these sources of emissions for reduction opportunities.

As mentioned earlier, a grade 1 leak represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous. A grade 2 leak is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard. A grade 3 leak is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous, and usually must be rechecked periodically.[44]

(3) Open Graded Leaks Being Monitored or Scheduled for Repair:

A few utilities indicated that they have no open leaks. Those that reported open leaks classified them into graded and ungraded leaks. The graded leaks are found in pipeline delivery systems whereas the majority of ungraded leaks that would be monitored are found in station facilities or customer meter sets. In general, the utilities have a good system for identifying leaks, and tracking them until repaired. Grade 2 leaks are a concern because the time to repair some grade 2 leaks appears to take longer than required by law.[45] Because utilities used cyclical surveys, all open leaks get rechecked and evaluated to ensure their grading is consistent with the current condition of the leak. The pipeline grade 3 leaks make up a significant portion of open leaks.

Customer MSAs are largest single source of estimated emissions. However, MSA emissions are based on the population of meters times an EF. The majority of actual leaking MSAs are non-hazardous; those that are hazardous are repaired on a similar protocol as grade 1 and 2 leaks. The utilities are not required to grade MSA leaks and other types of above ground leaks. However, any they identify as hazardous must be repaired in accordance with regulations.

The data request also required the utility companies to submit a list of all open leaks from 2009 to 2014. There was also concern regarding the year the leak was

[44] https://en.wikipedia.org/wiki/Gas_leak

[45] Per PHMSA - Leaks should be repaired or cleared within one calendar year, but no later than 15 months from the date the leak was reported. In determining the repair priority, criteria such as the following should be considered: a. Amount and migration of gas. b. Proximity of gas to buildings and subsurface structures. c. Extent of pavement. d. Soil type and soil conditions (such as frost cap, moisture and natural venting).

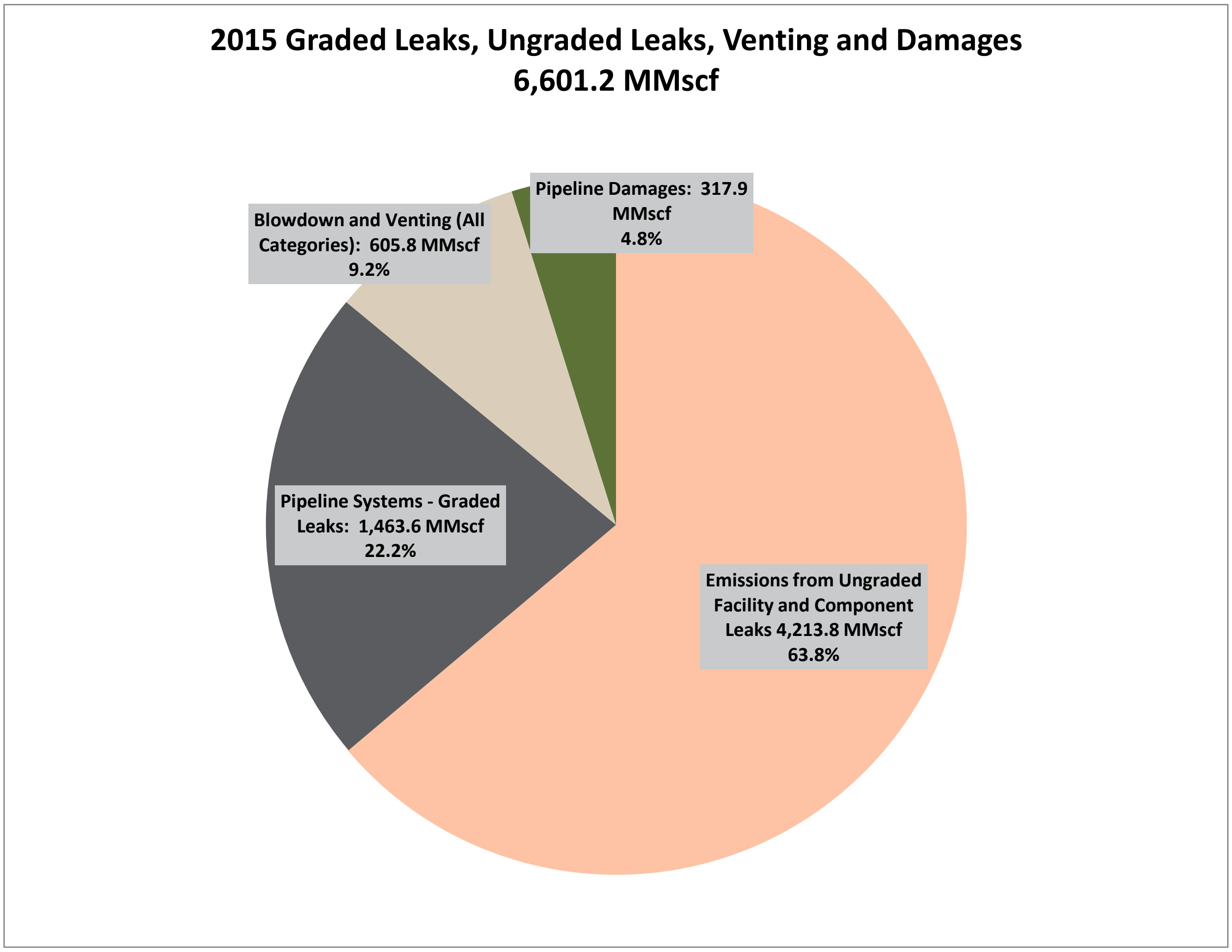
discovered and whether open leaks are rolled over into the next year and included in the emissions volume counted in each period until repaired. For example, a leak discovered in 2013 that was still leaking in 2015, and repaired in 2015, was included as an open leak during 2015 for purposes of estimating 2015 emissions. All emissions from graded leaks, no matter when detected during 2015 surveys, were calculated as if they were discovered on January 1, 2015. This was based on the concern that leaks occur prior to being detected and since we do not know when they began leaking, the utilities used January 1, 2015 to calculate 2015 emissions.

(4) Best Estimate of Gas Loss Due to Ungraded Leaks:

The natural gas lost due to fugitive leaks, other than graded leaks and not associated with venting, blowdowns or pipeline damages equates to 4,213.8 MMscf or 64% of the total reported emissions. For the purposes of this report, ungraded leaks are made up of fugitive leaks from customer meters, M&R stations, compressor stations and associated components, pipeline components and odorizers, storage facilities (compressors, components, and dehydrators) those that, based on the utilities grading system, fall outside their requirements for grading. These leaks are not the same as vented emissions (9% of total) (e.g. planned or unplanned blowdowns, releases etc.) and comprise a relatively significant volume of gas release harmful to the atmosphere.

Because of the large amount of estimated emissions that come from infrastructure in M&R stations, compressor facilities, MSAs and component equipment greater focus on leak mitigation through better designed equipment and facilities, use of better maintenance materials or practices, or improved operating practices should provide incremental emissions reductions over time, which when taken as a whole significantly reduce emissions.

Figure 6: Graded Leaks, Ungraded Leaks, Venting, and Damages:



(5) Baseline System-Wide Emissions Rate:

SB 1371 requires the establishment and annual monitoring of a system-wide leak rate for the transmission and distribution system.[46] The 2015 system wide emissions rate for SB 1371 utilities is 0.32% based on the numerator of 6,601.2 MMscf and denominator of about 2,056,950 MMscf throughput.

In this report, utilities provided their throughput figures used to calculate the emissions rate. Staff determined the System-wide Leak Rate using the total emissions from all source categories divided by the Total Annual Volume of Gas Transported.

Staff defined the Total Volume of Gas Transported as the combination of the following five sources:

1. Total Storage Annual Volume of Injections into Storage

[46] PUC Code Section 975(e)(6), Article 3 added by Stats. 2014, Ch. 525, Sec. 2. Effective January 1, 2015.

2. Total Transmission Annual Volume of Gas Used by the Gas Department
3. Total Transmission Annual Volume of Gas Transported to or for Customers in State
4. Total Transmission Annual Volume of Gas Transported to or for Customers out of State
5. Total Distribution Annual Volume of Gas Used by the Gas Department.

Every effort was made to prevent duplication of quantities that flow through the storage, transmission and distribution systems such that that volume was intended to be counted only once in the denominator.

The "Leak Rate Data" (tab two the Appendix 8 – Summary Workbook) shows the type and format of the information requested. [47]

Staff noted in the 2014 annual report, that "(t)he main reason given for error in calculating the system-wide leak rate was that LAUF volume is many times larger than gas lost due to known leaks and emissions. This could be due to atmospheric pressure and temperature during the metering process as well as metering accuracy. Overall, the utility data submitted to date indicate that leaks are far less than 1% of total gas moving through California's gas system making it difficult to quantify the volume on a system basis using meter readings."[48]

The stated concern was that the leak rate calculation led to double counting, or to negative quantities, or that throughput of the gas was incorrectly attributed to a different utility. In addition, some questioned whether there should be a separate storage, transmission and distribution emission rate. Due to the issues found with determining a California emissions rate in 2014, the 2015 data reporting templates were changed to better define throughput and estimate the emissions rate for this report.

This report does not separate the reporting of a storage, transmission and distribution leak rates, because of the difficulty in allocating the throughput to each sector. Further defining how to allocate the throughput data may help determine the leak rates for storage, transmission and distribution in the future.

[47] http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=9259

[48] Joint Air Resources Board/California Public Utilities Commission Staff report, Pgs. 12-13: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=10263

Lessons Learned

Further Work:

After the 2014 gas emissions report was issued significant effort went into revising the templates and data requested for the 2015 annual gas emissions report. The 2014 information received from stakeholder filings revealed that the information request needed incremental improvement, particularly more work needed to be done in quantification of leak volume, validating and updating EFs to better approximate category population emissions, and increasing the confidence in the methods that would ensure consistent and comprehensive reporting across utilities.

As such, based on formal comments by parties, Staff released a new data request spreadsheet.[49] The data request included a request for more detailed component emissions data, and asked for more event or equipment specific data. Staff also recognized the need to design a simple and reliable definition for quantifying system wide leak/emission rate and formalized a template for respondents to use to ensure consistency in the information. The Staff proposed a system wide leak/emissions definition that focuses on the total volume of emissions (estimated and actual for the period) divided by throughput (purchased, transported, and produced gas) for the transmission and distribution side with a corresponding rate for storage accounting for the amount stored.

The data templates improved the report submissions, but there were small gaps that required Staff to contact respondents for clarification and to work through missing or incomplete data.

2015 Issues and Opportunities:

1. The revised and improved templates helped develop a more consistent record of emission estimates for 2015. All the reporting entities did a very good job responding to the format of the data templates and addressing subsequent follow up questions from Staff. It was clear that the improvements made after the last annual report made a significant difference.

2. During the process of reviewing the data submissions, Staff found that the templates developed for reporting data did not contemplate counting emissions from leaks that occur in the utility's un-surveyed service territory.

[49] April 11, 2016: Administrative Law Judge's Ruling Issuing Staff Data Request Regarding 2016 Annual Reporting Requirements and Directing Responses by June 17, 2016, R.15-01-008. The appendices, referred to in the April 11, 2016 ruling, are posted at: http://www.cpuc.ca.gov/General.aspx?id=8829

One utility proactively calculated the emissions within its un-surveyed service territory and brought this to the attention of Staff. Staff determined that all utilities should estimate emissions from the portions of un-surveyed areas for this report. The utilities worked with Staff during the summer to develop a consistent emissions estimation method. The method was employed to estimate emissions occurring in the un-surveyed portions of their service territory. During 2017, Staff plans to conduct a working group meeting to share the methodology and algorithms used to estimate the total leaks in the utilities territory and refine it where possible. The templates will be updated with the changes noted during these meetings for use in the next reporting cycle (See Appendix E for a table of proposed template changes). Understanding the amount of leaks occurring in the entire service territory facilitates better estimates of pipeline emissions.

3. The 2014 and 2015 annual emissions reports used a mixture of emission estimation methods, such as population counts times EFs, leak detection, direct measurement and engineering estimates. The various methods used to estimate emissions may be sufficient for establishing a baseline from which to start measuring reductions, but going forward the emissions estimation methods should be reviewed periodically to continually improve the emission estimates going forward. More emphasis needs to be placed on finding ways to quantify emissions from infrastructure components and equipment.

4. Currently the use of EFs to estimate emissions from population (e.g. of pipeline miles, or meter sets) based estimates means that the only way to improve the emissions from these sectors would be to change the EF or the population. Greater reliance on scientifically based measurements and readings of actual leaks needs to be established to determine whether emissions reductions actually occur. The lack of effective and efficient volumetric measurement tools creates challenges implementing direct measurement of emissions. Additionally, there are challenges to cost effectively measure and repair minor underground leaks. While emission estimates based on EFs may be expedient and low cost, it appears advances in emissions reductions will be increasingly difficult to achieve unless fact based quantification methods become common practice. Fact based quantification methods become increasingly important for prioritizing mitigation actions and avoiding costly minor reductions.

5. Related to the concern about relying on EFs to estimate emissions, using outdated or obsolete EFs is an additional concern. The 1996 GRI EFs used for the 2015 Joint Report need to be reviewed because going forward they may not be appropriate due to their age and their applicability to California infrastructure. However, these were determined to be the most reliable EFs to consistently estimate emissions for 2015 annual report. Given that there are significant differences in topography and geography within a utility territory let alone the differences between the north and south parts of the state. Staff plans to review the EFs to identify issues with emission estimates, whether better EFs exist and, which EFs should be used going forward. Staff will have a workshop or webinar to vet these potential improvements.

6. Staff reviewed and analyzed the Data Reports and determined that some information in the Data Reports needed revision or augmentation that required follow up with the utilities. As a result, utilities resubmitted some of their data and responded to Staff questions. The additional time to vet the data submission was worthwhile in that it provided greater confidence in the consistency and integrity of the categorization of data. This exercise provided insight into what areas of the Data Templates may need to be updated or revised for clarity and consistency. For example, the data reporting templates though much improved over 2014 versions still did not clearly identify some information that should be reported and this caused confusion and inconsistent reporting. The inclusion of a sheet that calculates estimated leaks from un-surveyed areas should be added to the Appendix 4 workbook for Distribution Mains and Services. Breaking down the summary totals and counts by leak grade as well as by year detected would facilitate grouping and analyzing the data. In addition, the lack of column totals made following the data from supporting sheets to the summary sheet more difficult; therefore, column totals should be added to all worksheets and a summary sheet that ties back to each total within the workbook sheets provided as well. Staff also found that the templates data cells were not always clear and the intent not well defined. Therefore, the templates still need more clarification and better definitions of intent to help respondents provide the desired data. (See Appendix E for a table of proposed template changes.)

7. The process for updating reporting templates should be completed by March 31 of each year to facilitate capturing the data (See Appendix E for a table of proposed template changes). Then the report could be submitted by June 15 of each calendar year. This should be proposed in the First Phase Decision.

Going forward, familiarity with the data templates will increase with greater understanding both for respondents and Staff.

8. In the templates contained in Appendices 1, 4, and 6 for Transmission Pipeline, Distribution System Pipelines and Customer Meter Leaks respectively, respondents provided lists of their leaks. The transmission system template asked for graded and ungraded leaks, the Distribution System template asked for graded leaks and the Customer Meter Sets templates asked for ungraded leaks. During the consolidation of data, Staff used the number of miles of transmission pipeline times an EF to estimate pipeline emissions because there was concern that basing the emission estimate on existing leaks would not provide a reasonable estimate of emission from pipelines given the EF recommended was based on miles of pipe. There was no way to use a spot leak times an Emissions/mile EF that would provide a reasonable estimate of the Transmission pipeline leak volume. Staff learned that a method of quantifying the leak volume is a requirement before using a discrete leak count to estimate emissions volumes.

9. The second tab of the Appendix 8 Summary, labelled "leak rate data" requested that emissions be separated into graded, non-grade, and (vented) emissions where possible. After consolidating the leak rate data, Staff observed that the templates did not clearly state what should be put into each of the categories, and it appeared that respondents were confused as to what information was to be reported into each column. Staff recommends that a future workshop be held to work with respondents to define what information belongs in each of the types of emissions for the three segments being evaluated (Storage, Distribution and Transmission systems).

Conclusion

The report describes a framework for understanding the data submitted in the June 17, 2016, reports and subsequent submittals. Some of the major findings are:

- The baseline emissions estimate for 2015 from SB 1371 sector utilities totals 6,601.2 MMscf, equal to 2.96 MMTCO2e using the AR4 100-year methane GWP or8.51 MMTCO2e using AR4 20-year methane GWP, which provides a starting point to measure future natural gas emission reductions.
- Significant changes to emission factors (EFs) could occur based on improved information. Staff would need to consider the implications of the change and potential need to adjust the baseline to avoid incorrect accounting.

Nevertheless, the categories with the highest emission levels should be the starting point for establishing best practices to achieve the greatest amount of reductions for resources expended.

- The vast majority of ungraded emissions (64%, Figure 6) come from the components and equipment found throughout the delivery system. By parsing the emissions and identifying the volume of emissions and their sources, utilities can focus on the most cost-effective means to reduce emissions. By using actual emissions data, utilities should be able to address operating and maintenance practices, and component designs and materials to facilitate emission reductions.
- Among leaks that have been categorized as potential hazards, the grade 3 leaks make up a significant amount of leaks that are carried over year after year, making up 59% of the volume of all graded leaks. Even though grade 3 leaks are not considered a safety threat, cost-effective ways should be found to fix them sooner to reduce this persistent source of emissions.
- About 10% of the total emissions were from graded leaks in un-surveyed areas, estimated to occur between leak survey cycles. By reducing leak survey cycle times, the leaks occurring between cycles will emit for shorter lengths of time until they are detected and repaired. This effort should reduce emissions from graded leaks.
- Use of EFs may be acceptable in the short term for establishing the baseline emission levels. However, in order to better quantify emission reductions over time utilities must devise better ways to measure actual leak volumes. Relying on EFs may not fully account for emissions and reductions over time (e.g. every leak fixed is assumed to be emitting the same amount). Because it is difficult to quantify the actual volume of leaks and emissions, more work is needed to develop and improve California specific EFs until actual emissions measurements are available for the sources where it is feasible to directly measure emissions.
- Continuing refinement and improvement of the data reporting templates should increase transparency, and provide formats that consistently capture reliable leak and emission data for measuring changes in natural gas emissions.

January, 2017

Appendix A: Methods Used for Reporting and Estimating Leaks and Emissions

Rulemaking (R.) 15-01-008 to Adopt Rules and Procedures Governing Commission Regulated Natural Gas Pipelines and Facilities to Reduce Natural Gas Leaks Consistent with Senate Bill 1371, Leno.

Explanation of Methods Used for Reporting and Estimating Leaks and Emissions (Based on Appendix 9 of Data Request).

System Categories	Emission Source Categories	Emission Factor (EF) Source or Method	Description
Transmission Pipeline	Pipeline Leaks	INGAA	Due to lack of details about each leak (e.g. size of orifice, duration of leak, and volume) pipeline operators were instructed to provide emissions using the approved EF by number of miles of pipeline. It was determined that use of the emission factor from INGAA Greenhouse Gas Emission Estimation Guidelines for Natural Gas Transmission and Storage - Volume 1 GHG Emission Estimation Methodologies and Procedures (September 28, 2005 - Revision 2) - Table 4-4 study would be the best available for Transmission Pipeline emissions at this time.
	All damages (as defined by PHMSA)	Engineering Estimate	Event specific emissions data reported where emissions were estimated either from modelling or size of breach using pressure and duration to calculate the emissions.
	Pipeline Blowdowns	Engineering Estimate	The emissions calculated based on unique equipment attributes using the recommended EF most closely associated with that component to estimate emissions volume (corrected for pressure and temperature). These emissions were assumed to emit for the entire year. Actual measurements of emissions are difficult to calculate due to variations in operations and impact of new equipment versus old and the efficacy of maintenance practices.

	Component Emissions: Pneumatic Devices Pressure Relief Valves	GRI (1996)/ MRR	The emissions from components associated with transmission pipeline operations are based on the recommended EF's outlined in Appendix 9 of the Data Request. In some cases, the components did not meet the definition for the EFs and discrete approximations based on manufacturer provided leak rates, direct measurement of the different operating states as well as the for specific values recommended for use in calculating component specific leaks times number of units of equipment.
	Odorizer (Odorizer and Gas Sampling Vents)	TCR	The EF's recommended in Appendix 9 were used where directly applicable, however where transmission pipeline dehydrator equipment did not match the pipeline operators used the discrete equipment attributes and operations profile to estimate emissions. The methods used appeared to provide the best estimate of emissions given the variety and operating context of these facilities.
Transmission M&R	M&R Stations: - Farm Taps & Direct Industrial Sales - Transmission-to-Transmission Company Interconnect	MRR / GRI (1996)	The emission estimate for M&R stations are based on the EF's recommended in Appendix 9 multiplied by the population of each type of M&R station.
	M&R Leaks	MRR	The discrete leaks for M&R stations would be captured in the recommended EF's used to estimate the M&R station emissions and only where it could be determined that inclusion of discrete M&R leaks were not duplicated were they included in the count of emissions for this category.
	M&R blowdown	Engineering Estimate	Blowdown emissions were estimated based on the calculation of the unique equipment volume being vented corrected for pressure and temperature at the time of the release. The estimates for blowdown events in general provide a reliable emission estimate.
Transmission Compressor Stations	Compressor Equipment - Centrifugal and Reciprocating.	MRR	The emissions calculated based on the direct measurement of each compressor unit given its operating state and pressure, and then the emissions are based on number of operating hours in each operating state.

	Equipment and pipeline blowdowns	MRR	Blowdown emissions were estimated based on the calculation of the unique equipment volume being vented corrected for pressure and temperature at the time of the release. The estimates for blowdown events in general provide a reliable emission estimate.
	Components.	MRR	The equipment and component emissions are based on the leaks detected at the compressor stations times the recommended EF for that type of equipment per Appendix 9.
	Compressor Station Storage Tanks	MRR	These emissions are based on discrete tank pressure fluctuations due to exterior temperature fluctuations. The initial volume of gas release calculation is based on the starting and ending pressures assuming a constant temperature.
Distribution Mains and Services Pipelines	Pipeline Leaks - Below Ground	GRI (1996)	The emissions from leaks detected in 2015 in Distribution Mains and Service pipelines are calculated assuming that the leak was emitting from the first day of the calendar year through date of repair, or the entire year if not repaired in 2015, times the recommended EF. For identified leaks carried over from prior years the emissions are calculated from the beginning of the year through repair date (if repaired in 2015) or end of year times the recommended EF. In addition, leaks occurring in un-surveyed parts of operator's service territory were estimated based on the leak occurrence rate in the surveyed portion of the territory extrapolated based on number of years in the survey cycle to come up with the number of expected leaks in the un-surveyed territory times the recommended EF. This method of estimating the emissions from leaks occurring in un-surveyed portions of the service territory is considered a reasonable way of approximating the emissions and takes into account the frequency of leak detection surveys.
	Pipeline Leaks - Above Ground	GRI (1996)	See above for below ground leaks. Above ground leaks associated with MSAs are not counted in the volume or the numbers of leaks in order to prevent misleading representation of emissions as well as potential for duplication of emissions volumes.
	Blowdowns and Venting	MRR	Blowdown emissions were estimated based on the calculation of the unique equipment volume corrected for pressure and temperature at the time of the release. The estimates for blowdown events in general provide a reliable emission estimate.

	All damages (as defined by PHMSA)	MRR	Emissions from damages for AG Non-hazardous and MSA damages are calculated based on company emission factor for above ground facilities times the number of days leaking. For AG Hazardous and Below Ground Code 1 damages, emission was estimated based on based on engineering calculation using pipe size, damage opening size, and duration. For Code 2 and Code 3 damages, the emission factor for Distribution pipeline leaks was used. Where an estimate was not made at the time of the event, the emission was estimated from population of similar events with respective pipe material and pipe size.
	Components - Pneumatic Devices	Engineering Estimate	Emissions from components such as pneumatic devices are based on manufacturer specifications for bleed rate given the pressure.
	Odorizer (Odorizer and Gas Sampling Vents)	TCR	Not applicable for this category.
Distribution M&R Stations	M&R Stations: - Farm Taps & Direct Industrial Sales - Transmission-to-Transmission Company Interconnect	MRR / GRI (1996)	The emission estimate for M&R stations are based on the EF's recommended in Appendix 9 multiplied by the population of each type of M&R station.
	Blowdowns	Engineering Estimate	Blowdown emissions were estimated based on the calculation of the unique equipment volume corrected for pressure and temperature at the time of the release. The estimates for blowdown events in general provide a reliable emission estimate.
	Components	Engineering Estimate	The emissions from components are captured in the EF used on a station by station basis and the discrete information on a subset of components in the facility would duplicate emissions and present misleading count information. Until further work can be done with more comprehensive survey techniques relying on the recommended EF's on a station by station basis is considered the best estimate of emissions at this time.

Commercial, Industrial and Residential Meters	Residential and Commercial Meters	GRI (1996)	The emissions for this category is based on the MSA population count times the recommended EF per Appendix 9. There is substantial work currently being done to update EF's for MSAs and in future any updated EF's could be backward applied to 2015.
	Vented Emission from MSA	Engineering Estimate	Emissions from venting MSAs are based on the number of events times the estimated volume release by MSA and/or the type of activity.
Underground Storage	Facility Leaks	GRI (1996) / Engineering Estimates	Emissions in this category are based on EPA GHG Subpart W data EF's multiplied by the number of units of each equipment type.
	Compressor	Engineering Estimate	Emissions from storage facility compressors are calculated in the same manner as for compressors in other categories. See the description in the Compressor Station category.
	Blowdown and Venting	Engineering Estimate	Blowdown emissions were estimated based on the calculation of the unique equipment volume corrected for pressure and temperature at the time of the release. The estimates for blowdown events in general provide a reliable emission estimate.
	Components	MRR	Component emissions are based on the leaks detected during GHG leak survey pursuant to the GHG Mandatory Reporting Regulation and each component's EF times the population count. All leak and component emission estimates are based on the assumption that the leak is leaking the entire year.
	Dehydrator Emissions - Venting	MRR	The dehydrator emission estimate is based on the TCR Protocol for dehydrators.

Appendix B: Definitions

For the purposes of SB 1371, the definitions of "leak" and "gas -loss" and the formula for calculating a "system-wide gas leak rate" were defined in a different manner than elsewhere. A "leak" was defined as any breach, whether intentional or unintentional, whether hazardous or non-hazardous, of the pressure boundary of the gas system that allows natural gas to leak into the atmosphere. In essence, any vented or fugitive emission to the atmosphere is considered a "leak". Examples of leaking components include defective gaskets, seals, valve packing, relief valves, pumps, compressors, etc. Gas blowdowns during the course of operations, maintenance and testing (including hydro-testing) were also included as leaks. Consequently, this leak definition is broader than the Pipeline Hazardous Material and Safety Administration's (PHMSA) definition.

The gas utilities are required by Federal Law, 49 CFR 192, to survey their systems for leaks, which could be hazardous to public safety or property. To accomplish this, the gas utility companies developed graded leak programs to detect, prioritize and repair the safety related types of leaks. The same definitions are used within this report and are as follows:

- Graded Leaks –hazardous leaks or, which could potentially become hazardous as described below:
    - A "grade 1 leak" is a leak that represents an existing or probable hazard to persons or property and requiring prompt action, immediate repair, or continuous action until the conditions are no longer hazardous.[50]
    - A "grade 2 leak" is recognized as being non-hazardous at the time of detection but justifies scheduled repair based on the potential for creating a future hazard.51
    - A "grade 3 leak" is a leak that is not hazardous at the time of detection and can reasonably be expected to remain not hazardous.[52]

- Vented Emissions are releases of gas to the atmosphere, which occur during the course of operations or maintenance, for a safety reason. Some examples are:
    - Purging (a.k.a. "blowdown") gas prior to hydro-testing a line.

50 Refer to G.O. 112F for more information.
51 Ibid.
52 Ibid.

- o Gas releases designed into the equipment function, such as gas emitting from relief valve vents or pneumatic equipment.
- o Gas releases caused by operations, maintenance, testing, training, etc.
- o Ungraded Leaks are the remaining leaks, which are not hazardous to persons and/or property.

For further information please see CPUC General Order (G.O.) 112, Revision F.

Lastly, in 2014 the system-wide gas leak rate was calculated as a percent of total input for the 12 months ending June 30 of the reporting year. However, Staff determined that there were problems with this calculation and opted not to report a leak rate using this formula. The formula for calculating a system-wide gas leak was written as follows:

Pipeline Hazardous Material and Safety Administration (PHMSA) Modified Equation for Lost and Unaccounted for (LAUF) Gas:

[(Purchased gas + produced gas + transported gas entering the gas system) minus (customer use +company use + appropriate adjustments + gas injected into storage + transported gas leaving the gas system)] divided by (Purchased gas + produced gas + transported gas entering the gas system) = System Wide Gas Leak Rate.

Note: transported gas includes gas purchased by customers and transported in common carrier pipelines.

In section 5, "Baseline System-Wide Emissions Rate," Staff determined the value for 2015 to be 0.32% by using the total natural gas emissions from all source categories (6,601.2 MMscf) divided by the Total Annual Volume of Gas Transported (2,056,950 MMscf). The five sources for Total Annual Volume of Gas Transported are listed on pages 29 and 30 of this report.

Appendix C: Article 3, Section 975 (c) and (e)(6)

Article 3. Section 975

(c) As soon as practicable, the commission shall require gas corporations to file a report that includes, but is not limited to, all of the following:

(1) A summary of utility leak management practices.

(2) A list of new methane leaks in 2013 by grade.

(3) A list of open leaks that are being monitored or are scheduled to be repaired.

(4) A best estimate of gas loss due to leaks.

(e) The rules and procedures adopted pursuant to subdivision (d) shall accomplish all of the following:

(6) to the extent feasible, require the owner of each commission-regulated gas pipeline facility that is an intrastate transmission or distribution line to calculate and report to the commission and the State Air Resources Board a baseline system-wide leak rate, to periodically update that system-wide leak rate calculation, and to annually report measures that will be taken in the following year to reduce the system-wide leak rate to achieve the goals of the bill.

Appendix D: Conversion of Natural Gas to Carbon Dioxide Equivalents

The conversion of natural gas volume to carbon dioxide equivalent mass requires the use of GWP. ARB used GWP25 (100-year value) from the IPCC, AR4, for the 2014 GHG emissions inventory. The following calculations show the conversion of the total natural gas emissions from this report. The conversion was done in two steps. In the first step, the calculation shows the volumetric natural gas that contains exactly one metric ton of methane.

$$1\ MT\ CH4 * \frac{2{,}204.62\ lbs\ CH4}{1\ MT\ CH4} * \frac{1\ lb\ mole}{16.04246\ lb\ CH4} * \frac{379.48\ scf\ of\ CH4\ gas}{1\ lb\ mole}$$

$$* \frac{1.0\ scf\ of\ natural\ gas}{0.934\ scf\ of\ CH4\ gas} * \frac{1\ Mscf}{1{,}000\ scf} = 55.835\ Mscf\ of\ natural\ gas$$

Using this volumetric unit, the 2015 total natural gas emissions, 6,601 MMscf, is equivalent to about 3.0 MMTCO2e, as shown below:

$$6{,}601{,}169\ Mscf\ natural\ gas * \frac{1\ MT\ CH4}{55.835\ Mscf\ of\ natural\ gas} * \frac{25\ CO2e}{1\ CH4} *= 2{,}955{,}671\ MT\ CO2e$$

ARB has also used GWP 72 (AR4, 20-year) in the Short Lived Climate Pollutant Plan and Oil and Gas Regulation. Based on the higher GWP, the 2015 total natural gas emissions, 6,601 MMscf, is about 8.5 MMTCO2e, as follows:

$$6{,}601{,}169\ Mscf\ natural\ gas * \frac{1\ MT\ CH4}{55.835\ Mscf\ of\ natural\ gas} * \frac{72\ CO2e}{1\ CH4} *= 8{,}512{,}332\ MT\ CO2e$$

The use of 1.0 scf of natural gas per 0.934 scf of CH4 gas accounts for composition of natural gas being not 100% methane. The American Gas Association published a value of 93.4% to be used as a default methane concentration that is comparable to what utilities reported.[1]

The standard cubic foot "scf" for measuring gas is based on 60 degrees Fahrenheit at atmosphere pressure.

In addition, utilities reported trace amounts of concentration for ethane, inert gases, and other elements and compounds. There was not an entry for carbon dioxide explicitly, and so it cannot be assumed that all of the inert gas was carbon dioxide. A calculation was performed that showed CO2 emissions from the inert gases would be less than 0.1% of the total, and is excluded in this report.

Footnote:

1. AGA, GHG Guidelines, page 39, April 18, 2008, http://s3.amazonaws.com/zanran_storage/www.aga.org/ContentPages/18068841.pdf

Appendix E: Table of Proposed Changes to Data Request Templates

Application	Proposed Template Modification	Explanation
Appendices 1 through 7; All Template sheets.	Include a note to each tab for the utilities' formula used to calculate the Annual Emissions, rather than copy and paste-as-value. Please do not include VLOOKUP unnecessarily in the data sheets.	By showing the formula, the review process is expedited. It will also be apparent if EFs or Engineering calculations are used. Staff is interested in seeing calculation assumptions used in estimating emissions of blowdowns. In cases where the formula cannot be shown since it is more complicated than the multiplication of terms on the row, please note in the explanations column.
Appendices 1 through 7; All Template sheets.	A note has been added to each tab for utilities to include the AutoSum function at the end of the Annual Emissions column. Then highlight the total cell orange.	There have been instances of an error made in transferring the total from individual appendices with the Summary 8 appendix.
Appendices 1 through 7; All Template sheets.	A note has been added to each tab to include the total leak, event and population counts.	This will expedite the review process.
Appendix 4: Distribution Mains and Services	Include a new tab for Estimated Un-surveyed Leaks for estimating the number of leaks, and their associated emissions, from un-surveyed mains and services. A standardized calculation methodology is also proposed.	In the review of 2015 Data, it became apparent that this significant emission source was not accounted for. Staff worked with utilities that do not survey all of their mains and services annually to account for leaks and estimate emissions that occur in the un-surveyed areas.
Appendix 4: Distribution Mains and Services	Include a new tab summarizing all of the pipeline leak data (e.g. un-surveyed and surveyed) for emissions, grade, and counts.	This will expedite the review and analysis process.
Appendix 4: Distribution Mains and Services	Include a new tab for capturing leaks detected from meter set assemblies during the distribution mains and services leak detection surveys. Add a note to the pipeline leaks tab to exclude any meter set assembly leaks formerly listed therein, and list them in the new tab set up to capture the MSA data.	Emissions from meter set assembly leaks are already accounted for in Appendix 7, Customer Meters. In the review of 2015 Data, the inclusion of MSA leaks on this tab required further consultation with utilities to accurately count the number of mains and services leaks and prevent double counting. Therefore, an extra tab will be added to allow utilities to capture above ground meter set assembly leak data. The estimated emissions in this new tab would not be included in the annual emissions total.

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Appendix 4: Distribution Mains and Services	Delete the tab for Odorizers.	Odorizer facilities are not part of the Distribution Mains and Services system, therefore, there were no emissions from this category in 2015. Including a tab for this category is unnecessary.
Appendix 8: Summary Table	Two of the Emission Types listed "Graded/Non-graded Leaks" and "Non-graded Leaks/Emissions". The Emissions Types will be changed so that only one type per category is allowed. Where additional emission types exist within a category then an additional line needs to be added for the second (or third) Emission type. For example, the type "Graded/Non-Graded Leaks" would either be shown as "Graded Leaks," "Non-Graded Leaks"; or for "Non-graded Leaks/Emissions" either "Non-Graded Leaks" or "Emissions" would be used.	Staff determined that only one emissions type should be listed per category line item. For example, either the leak type should be "Graded" or "Non-Graded" but the category line item emissions data should not contain both types of emissions. This should facilitate analysis and making charts for the Joint Report.
Appendix 8: Summary Table	Include the AutoSum function at the end of the Annual Emissions column. Then highlight the total cell orange.	Staff determined that the total emissions per utility should be displayed so that it can be used as a reference when consolidating the data.
Appendix 8: Summary Table	On the tab for NG specification, Carbon Dioxide has been added.	Staff determined that carbon dioxide was necessary to be added to the list of NG specifications.