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

Analysis of the Utilities' May 15th, 2015,  
Methane Leak and Emissions Reports  
Required by Senate Bill (SB) 1371 (Leno)  
and Rulemaking (R.)15-01-008

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## Executive Summary

The California Air Resources Board (ARB) and California Public Utilities Commission (CPUC) are tasked by Senate Bill (SB) 1371 (Statutes 2014, Chapter 525) and CPUC Rulemaking (R.) 15-01-008<sup>1</sup> with undertaking an initiative to account for and reduce methane emissions from leaks in the natural gas transmission, distribution and storage units in California. SB 1371 also recognized that the economic cost must be considered in order to reach the gas reduction goals as cost-effectively as possible. As noted in ARB's draft Short-Lived Climate Pollutant (SLCP) Reduction Strategy,<sup>2</sup> California can reduce methane emissions by 40 percent below current levels through a collaborative and mixed approach that combines incentives, public and private investment, and regulation. Environmental Defense Fund (EDF) portrays similar conclusions at a national level in a recent report, with particular focus on oil and gas systems:

“Methane is an important climate change forcing greenhouse gas (GHG) with a short-term impact many times greater than carbon dioxide. Methane comprised 9% of U.S. greenhouse gas (GHG) emissions in 2011 according to the U.S. EPA Inventory of US Greenhouse Gas Emission and Sinks: 1990-2011, and would comprise a substantially higher portion based on a shorter timescale measurement. Recent research also suggests that mitigation of short-term climate forcers such as methane is a critical component of a comprehensive response to climate change. Emissions from the oil and gas industry are among the largest anthropogenic sources of U.S. methane emissions. At the same time, there are many ways to reduce emissions of fugitive and vented methane from the oil and gas industry and, because of the value of the gas that is conserved, some of these measures actually save money or have limited net cost.”<sup>3</sup>

In partial fulfillment of R.15-01-008 scoping memo objectives, this report summarizes reports submitted to ARB and CPUC on May 15, 2015, from the gas utilities, which reported on the categorization of numbers and volumes of gas leaks and other emissions in their respective systems. Emissions will be discussed from both pipeline

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<sup>1</sup> [“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,” issued January 22, 2015.](#)

<sup>2</sup> Draft issued September 30, 2015; <http://www.arb.ca.gov/cc/shortlived/shortlived.htm>

<sup>3</sup> [Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, March 2014, Prepared for Environmental Defense Fund, Prepared by ICF International, 9300 Lee Highway, Fairfax, VA 22031; Pg. 1-1.](#)

leaks and other emissions throughout the systems. 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. 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 not hazardous. There are also vented emissions resulting from intentional releases, or venting. Finally, the remaining leaks are classified as ungraded leaks, such as leaks at customer meters. The reports also included discussions of their leak and emission detection and mitigation programs.

As will be discussed, there are still large uncertainties and concerns about this data. This report provides a summary; but conclusions on magnitude and distribution of sources cannot be definitively made until data issues have been resolved.

## **Findings**

A key finding from the reports is that, in 2014, according to the utility data, emissions from ungraded leaks and vented emissions comprise 89% of the total system emissions (Figure 2) from the gas transportation and distribution system, or more than eight times the amount of graded leaks. After ungraded leaks and emissions, emissions from grade 3 leaks are the second highest category, about equal to the volume of grade 1 and 2 leaks combined (Figure 4). Grade 3 leaks are not considered a safety threat so the urgency to repair them depends on their individual volume, such that grade 3 leaks may not get repaired until convenient and cost-effective, which may take several months to years (Figure 8).

It is clear that more work needs to be done to address vented emissions, ungraded leaks, and grade 3 leaks. Changing the way we think about these emissions will be important to focus more resources on establishing new policies and practices that cost-effectively address a larger proportion of these types of leaks in order to reach the gas leak and emission reduction goals.

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

For instance, the number of leaks detected from 2013 to 2014 increased 21% overall – due partly to improved leak detection technology – with 6% grade 1 and 46% grade 2 increases in detected leaks, and a 4% decrease for grade 3. The count of open leaks changed similarly by grade 5%, 13% and -6%, respectively, but overall open leaks only increased 4%.

However, the 2014 leak volume reflects a 5% decrease from 2013 levels due to a dramatic increase in grade 2 leak repairs even though it is slightly offset by a decrease in the number of grade 3 leak repairs. There is an increase in leak volume in grade 1 and grade 3 of 8% and 7%, with a decrease of 36% in grade 2 volume.

## **Further Work**

The information received from stakeholder filings reveals that the information request from May 15, 2015, needed improvement, particularly more detail to ensure consistent and comprehensive reporting across utilities. As such, staff has released a proposed new data request spreadsheet. In addition to the detailed data, staff recognized the need to design a simple and reliable definition for quantifying a system wide leak/emission rate. The CPUC, Safety and Enforcement Division, and ARB staff (staff) proposed a system wide leak/emissions definition as part of the revised templates being considered by parties and for potential future adoption by the CPUC.

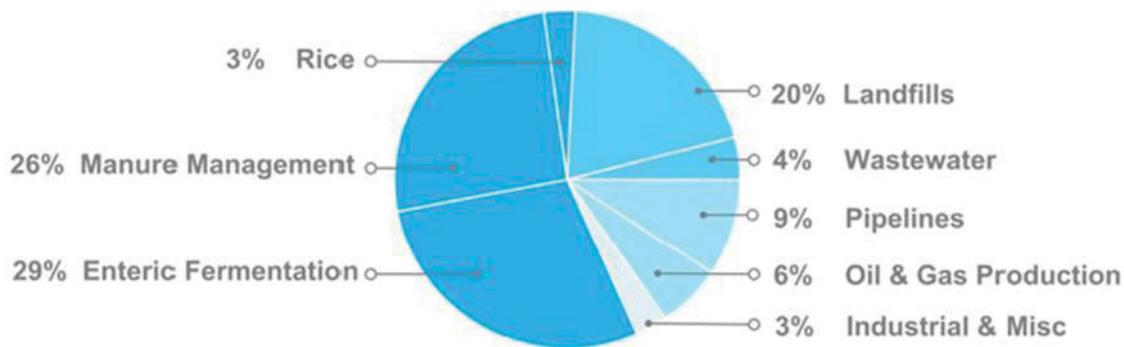
Understanding the emissions data will help in developing reasonable emission factors (EFs) and best practices that should be used for the different categories of pipes and equipment by California's gas utilities. It is important to recognize that each utility has its own unique geography, age of pipes and equipment, and maintenance policy and practices.

The preliminary reports indicated that the major sources of ungraded leaks were from emissions or "blowdowns" of gas from the transmission or distribution systems, in order to conduct maintenance, and leaks from threaded fittings at meter sets. While the reports provided some estimation of the volume of these emissions and leaks, more work needs to be done to better quantify actual volumes rather than relying on emission factors and estimates.

## Introduction

Methane is 72 times (IPCC, AR4) more potent a greenhouse gas (GHG) than carbon dioxide, on a 20 year time frame. Researchers have identified the oil and natural gas industry as one of the major sources of methane emissions in the United States. California Air Resources Board staff has also analyzed sources of methane emissions as part of the annual Greenhouse Gas Inventory and the draft Short-Lived Climate Pollutant (SLCP) Reduction Strategy. As shown in the chart below, methane emissions from the transmission and distribution sector (i.e. pipelines) accounted for approximately 9% of total methane emissions in California in 2013. Methane emissions are about 10% of the total GHG emissions in the State.

Figure 1: California Methane Emission Sources  
41.1 MMTCO<sub>2</sub>e Emissions in 2013<sup>4</sup>



Senate Bill 1371 (SB 1371) (Leno, 2014) was signed by Governor Brown on September 21, 2014, to reduce methane emissions from leaks in the natural gas transmission, distribution and storage units in California. Reducing emissions will mean more natural gas is delivered to the end-user and less is emitted to the atmosphere to contribute to climate change.

<sup>4</sup> [http://www.arb.ca.gov/cc/inventory/data/tables/ghg\\_inventory\\_by\\_sector\\_00-13\\_20150424.xlsx](http://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_by_sector_00-13_20150424.xlsx); The Pipeline equivalent volume of Methane (CH<sub>4</sub>) (comprising transportation and distribution) comes to 3.81 MMTCO<sub>2</sub>e, or 9.3% of the total Methane emissions of 41.1MMTCO<sub>2</sub>e. The 3.81 MMTCO<sub>2</sub>e is equivalent to 0.83% of all estimated 2013 Green House Gas (GHG) emissions in California that totaled 459.3 MMTCO<sub>2</sub>e. The Methane emissions alone totaled 41.1 MMTCO<sub>2</sub>e or 9.0% of all GHG emitted in California from all sources.

Staff prepared this report to provide a summary of the reports submitted by the utility companies on May 15, 2015 (May 15<sup>th</sup> Reports). The May 15<sup>th</sup> Reports were developed to meet the requirements of Article 3, Section 975 (c) (1 through 4) and (e)(6), of the State of California Public Utilities Code, which states:

### Article 3. Section 975 Methane Leak Abatement

(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.

(d) Not later than January 15, 2015, the commission in consultation with the State Air Resources Board shall commence a proceeding to adopt rules and procedures for those commission-regulated pipeline facilities that are intrastate transmission and distribution lines, as respectively described in paragraphs (1) and (2) of subdivision (a) of Section 950, to achieve the goals of subdivision (b).

(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 subdivision (b).

CPUC staff presented a preliminary analysis of the May 15<sup>th</sup> Reports at a CPUC/ARB workshop on September 23, 2015. Upon additional review of the reports, staff determined that some information in the May 15<sup>th</sup> Reports was incomplete and required follow up with the utilities. As a result, utilities resubmitted their data and responded to staff questions, which delayed this summary report.

After a comprehensive review of the May 15<sup>th</sup> Reports, staff determined that the original reporting template was not clear and comprehensive for a number of categories, including emissions from compressors stations, compressors, and metering and regulating stations. Data are needed from all of the emission source categories to accurately estimate total emissions from the natural gas transmission and distribution system. As such, following ARB/CPUC review of parties' comments on a newly revised template, a final revised template will be provided to the utility companies for the May 15, 2016, submittals.

The revised template will make future reports more accurate and complete. Subject to further review, the May 2016 reports could represent the baseline against which future methane emission reductions will be compared.

## Initial Data Request

On January 9, 2015, the CPUC staff sent out a data request to all utilities in California to collect the information required by Article 3, Section 975 (c) and (e)(6).

### Definitions

For the purposes of SB 1371, the definitions of “leak” and “gas lost” and the formula for calculating “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 which allows methane 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 blow-downs during the course of operations, maintenance and testing (including hydro-testing) were also included as leaks. Consequently, this definition of a leak is broader than the Pipeline Hazardous Material and Safety Administration (PHMSA) definition of leak.

The gas utilities are required by Federal regulation, 49 CFR Part 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 – Leaks which are hazardous, or which could potentially become hazardous as described below<sup>5</sup>:
  - 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.
  - A "grade 2 leak" is a leak that is recognized as being not hazardous at the time of detection but justifies scheduled repair based on the potential for creating a future hazard.

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<sup>5</sup> Refer to G.O. 112F for more information.

- 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.
- Vented Emissions are releases of gas to the atmosphere, which occur during the course of operations or maintenance. Some examples are:
  - Purging (a.k.a. "blowdown") gas prior to hydro-testing a line.
  - Releases of gas which are a design function of equipment such as gas emitting from relief valve vents or pneumatic equipment.
  - Releases of gas caused by operations, maintenance, testing, training, etc.
- 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, as approved by Commission in Decision D.15-06-044 issued July 1, 2015.

The PHMSA definition for "gas lost" was used for the report except that "gas lost" was not adjusted for losses from construction, purging, line breaks, operations, maintenance whether intentional or unintentional. In other words, these types of losses were considered part of "gas lost."

Lastly, the system-wide gas leak rate was to be calculated as a percent of total input for the 12 months ending June 30 of the reporting year. The formula for calculating system-wide gas leak was written as follows:

PHMSA Modified Equation for Lost and Unaccounted for (LUAF) Gas:

$$\frac{[(\text{Purchased gas} + \text{produced gas} + \text{transported gas entering the gas system}) \text{ minus } (\text{customer use} + \text{company use} + \text{appropriate adjustments} + \text{gas injected into storage} + \text{transported gas leaving the gas system})]}{(\text{Purchased gas} + \text{produced gas} + \text{transported gas entering the gas system})} = \text{System Wide Gas Leak Rate.}$$

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

## Data Request Findings

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 in 2013 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.

Eleven natural gas utilities<sup>6</sup> submitted responses to the data request. Seven companies transport, distribute and store natural gas and the remaining four exclusively store natural gas. However, one utility was exempted from reporting since it only transports liquefied petroleum gas. This report will avoid identifying individual companies' data responses, but will report data in aggregate. The companies will collectively be identified as "utilities."

Below are findings in each of the five categories:

**(1) Leak management practices**

Each utility company 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. Gas companies also noted using novel practices and newer technologies. Some examples of different practices include Pacific Gas & Electric Company (PG&E) using the Picarro technology to assist in leak detection, while another utility and San Diego Gas and Electric Company (SDG&E) conduct a walking gas leak survey of their pipeline right-of-way using flame ionization leak detection devices. Wild Goose Storage (WGS) flies over pipelines fourteen times per year to visually look for anomalies or for third party activity close to the lines as part of their leak management practices. Southwest Gas (SWG) currently utilizes a combination of equipment, including flame ionization, Remote Methane Leak Detection (RMLD), and amplified catalytic sensor devices, to search for the presence of natural gas leaks. SWG also utilizes the newer Detecto Pak Infra-Red (DPIR)<sup>7</sup> process, as well as the standard Hydrogen Flame Ionization (HFI).

In addition, PG&E reported on their proactive efforts in reducing its leak repair backlog by addressing non-hazardous leaks through repair or replacement instead of rechecking them per requirements.

"Specifically, PG&E has reduced its Grade 3 leak backlog by 32 percent over the last three years using this approach. ...In 2014, PG&E deployed the use of Picarro leak detection technology... surveying 187,000 services. PG&E also created the leak optimization pilot team called Super Crew. This pilot program established a

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<sup>6</sup> Alpine Gas Storage, Central Valley Storage, Gill Ranch Storage, Lodi Gas Storage, Pacific Gas and Electric Company, Southern California Edison, Southern California Gas Company, San Diego Gas and Electric Company, Southwest Gas Company, West Coast Gas Storage, Wild Goose Storage.

<sup>7</sup> The DPIR does not require the operator to carry a supply of hydrogen fuel, as it utilizes an infrared optical gas detection system.

new process model to help work flow more efficiently across teams focused on performing leak survey and leak repair. For example, the Super Crew team was able to leak survey 107,000 services and repair over 3,100 leaks (including repairing meter set leaks and replacing 77 percent of all leaking services) in only 41 business days. “<sup>8</sup>

However, the leak management practices described in the May 15<sup>th</sup> reports may not represent the universe of best leak management practices. To address this, staff held several working group discussions with all the parties to develop a more robust list of potential best practices based on technologies proven to detect and reduce leaks. During December 2015 and January 2016, three teleconferences and two meetings were held to discuss the following topics:

- Transmission blowdowns and M&R Station blowdowns
- Customer Meter and PHMSA “minor” releases (threaded connection times and required repair times for graded leaks)
- Storage – control vents, leaks, blowdowns, storage compressors, casings, other sorts of leaks and emissions
- Compressor stations – leaks from valves, connections, meters, vents, packing, blowdowns, etc.
- Mitigation choices for Working Group Proposal

Based on the discussions with the utility companies, trade unions, and other parties to the rulemaking, the CPUC will publish a complete list of the best leak management practices subject to formal review by parties. The list is also expected to include the United States Environmental Protection Agency’s best leak management practices in their Natural Gas STAR (US EPA) Program.

## **(2) New methane leaks in 2013 by grade**

All utility companies listed the number of methane leaks discovered in 2013. They provided detailed information for such leaks including: the grade type, emission source, pipe size, date discovered, date repaired as well as the size of the leak in volume. The size of the leak in volume was generally estimated using emission factors from a recent

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<sup>8</sup> Pacific Gas and Electric Company’s Amended Gas Leak Report (Period 2013-2014): October 16, 2015; pg. 7.

Washington State University study, but there was not consistency since there was no guidance in the original template on how to estimate leak volume. PG&E experienced a substantial increase in grade 3 leaks from 2013 to 2014, due primarily to using the Picarro technology, which is approximately 1,000 times more sensitive than previous technology. A graph of the quantity of leaks in 2013 and 2014 by grade is shown in Figure 3.

One of the significant findings was that ungraded leaks and vented emissions make up the majority of emissions shown in Figure 2. As mentioned earlier, ungraded leaks are those that are neither graded leaks nor vented emissions.

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. Where 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.<sup>9</sup>

Ungraded leaks are those that, based on the utilities grading system, fall outside their requirements for grading. These leaks are not the same as vented emissions (e.g., planned or unplanned blowdowns, releases, etc.) and comprise a relatively significant volume of gas release harmful to the atmosphere.

Several workshops and working group meetings/calls have occurred or will occur to actively review and discuss aspects of the proceeding:

- Gas Leak Technology Forum Hosted by SoCalGas for Leak Detection Vendors
- Working Group Workshop on Best Practices Based on "Target" Emissions
- Working Group Proposal on Analysis of Leaks and Best Practices
- CPUC/ARB Workshop on Targets, Compliance and Enforcement

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<sup>9</sup> Refer to G.O. 112F for more information.

### **(3) Open leaks that are being monitored or are scheduled to be repaired**

A few utilities indicated that they have no open leaks. However for the utility companies that reported open leaks, the number of open leaks did not equal the number of discovered leaks minus the number of repaired leaks. To correct this issue, these companies were requested to resubmit their data.

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 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 2008 that was still leaking in 2009, and repaired in 2010, was not listed as an open leak at the end of 2009. There was agreement that going forward utilities would report all open leaks and indicate which ones were carried over from prior years. However, this was not done in this submission and therefore the emissions will be underestimated.

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

The data request required a best estimate of total gas lost due to leaks annually from June 30, 2008, through June 30, 2014.<sup>10</sup> Some of the smaller utilities reported that they have no gas loss due to leaks. Eight of the eleven utilities reported a gas loss due to leaks. Further investigation needs to be made as to why a few small utilities report no leaks.

### **(5) Baseline system-wide leak**

The data request specified a baseline system-wide leak rate equation based on a modified PHMSA equation for Lost and Unaccounted For (LUAF) gas. However, the utilities reported problems using the equation. Some of the problems were due to misunderstanding of the terms of the equation, while other problems were apparently due to the terms of the equation being incompatible with the bookkeeping and accounting methods of at least one utility. The latter problem led to the inability of the utility to calculate one or more terms for the equation.

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<sup>10</sup> Some reported their estimate on a calendar year basis and others reported on the 12 months July 1<sup>st</sup> through June 30<sup>th</sup>. We used their reported amounts in this first year of the program to obtain a reasonable estimate of annual natural gas emissions.

Staff has also concluded that the PHMSA equation for LUAF gas is not a good basis for calculating a system-wide leak rate. This is because the equation calculates the volume of gas lost for ANY reason, including metering margin of error and deviations in gas volume due to temperature and pressure. These errors and deviations turned out to be very large in comparison to actual known leaks and emissions.

Based on feedback from the Respondents, staff has worked to develop an improved baseline system-wide leak rate equation for the next data request.

The main reason given for error in calculating the system-wide leak rate was that LUAF 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.

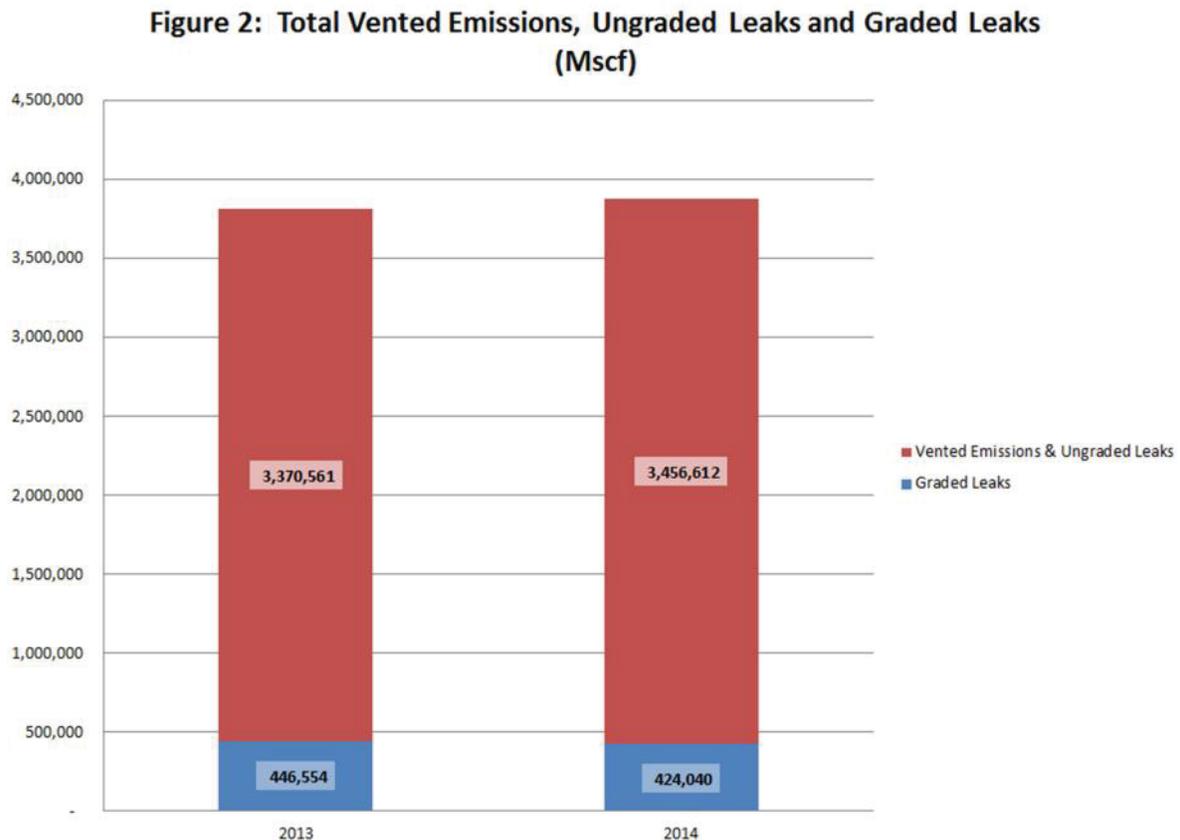
Lastly, some utilities provided additional information including: number of accidents that occurred, top ten emission categories, and top ten leaks. However, the information did not include data for compressor stations, compressors, metering and regulating stations, dig-ins, customer services, and storage information. This information is required to estimate the total emissions from the transmission and distribution system in California. Also, various emission factors were used to estimate emissions for the same emission source categories.

Given the lack of consistency and comprehensiveness, any findings should be recognized as inconclusive. Staff has worked with the utilities and others to develop an improved approach for the next data request.

## Data Request Summary

CPUC staff presented a preliminary analysis of the May 15<sup>th</sup>, 2015 report data at the workshop held on September 23, 2015. As mentioned above, some utilities were asked to resubmit their report due to missing data. However, based on the original information from the utility companies, the data showed that the majority of the methane emissions are ungraded leaks and vented emissions. The volume of graded leaks in 2013 and 2014 was around 450,000 Mscf and 420,000 Mscf, respectively, while the volume of ungraded leaks and vented emissions for both years was around 3,400,000 Mscf.

The chart for Figure 2 reflects the all California vented emissions, ungraded leaks and graded leaks reported by utilities per the CPUC data request. For this purpose, vented emissions and ungraded fugitive leaks are combined together. Also, the amount from graded leaks is shown as a subset of the total.



Graded leaks represent 11.7% and 10.9% of all emissions and leaks reported for 2013 and 2014 respectively. The following charts focus on graded leaks because that is where staff used disaggregated data.

Apparently, confusion over the May 15, 2015, report request resulted in respondent reports with differences between calculated and estimated emissions totals being reported. Where it was clear to staff that the responses met the intent of the request, then staff used the total reported. However, where staff could discern that the reported total was for a subset of leaks and/or vented emissions, then staff combined those subtotals to arrive at an appropriate cumulative total. Otherwise, where the reported amounts could not be justified, they were not used.

Since the majority of the data reported was on the graded leaks, several graphs on graded leaks were presented at the workshop and are shown in the next figures. Figure 3 shows the distribution by count of grade 1, grade 2, and grade 3 leaks for 2013 and 2014. Some reported their data on a fiscal basis and some on a calendar year basis. Both data sets were combined to approximate counts that would occur over a 12-month period. Using the tables provided by utilities, staff counted leaks that were open at any time during each period per their reporting method not singling out just those detected in each year.

The increase or decrease in count of open graded leaks does not correlate to leaks detected in any given year. The count depends on the number detected and how quickly repaired. Some utilities may have increasing leak detection rates and falling leak counts, and others may have increasing leak counts due to either or both increased/decreased detection rates and increased/decreased repair rates.

**Figure 3: Count of Graded Leaks  
2013 and 2014**

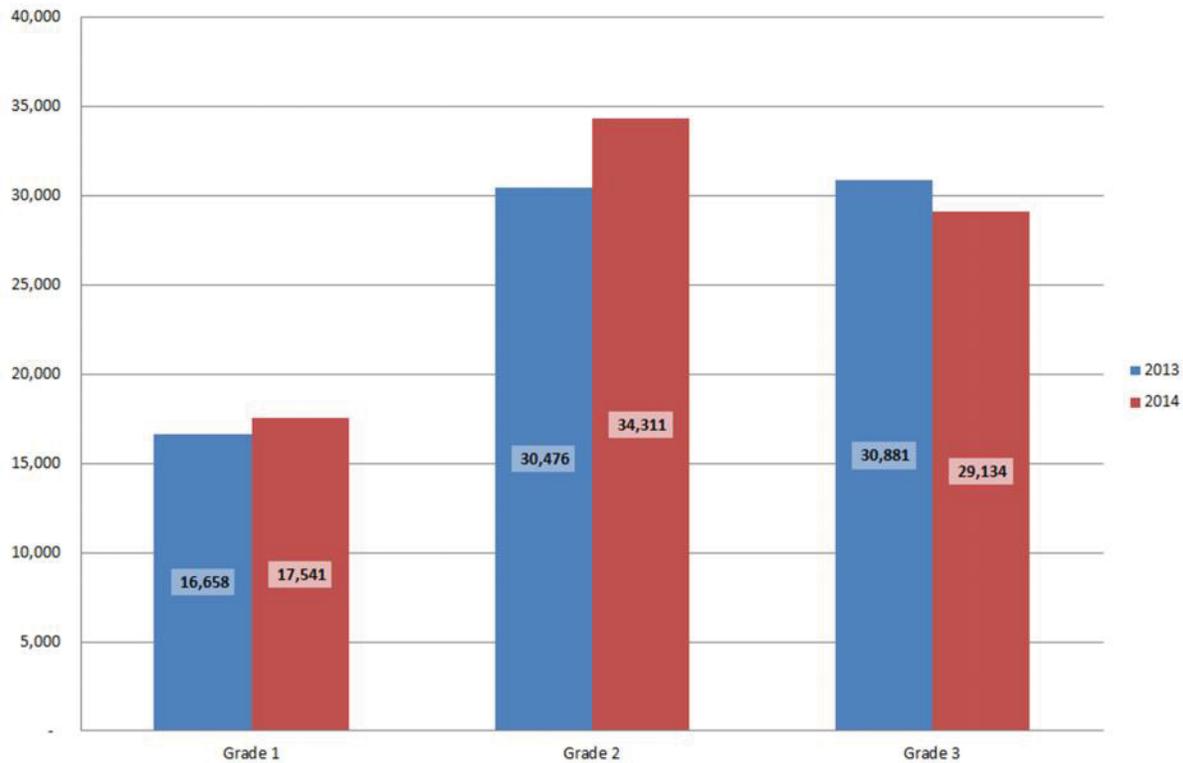
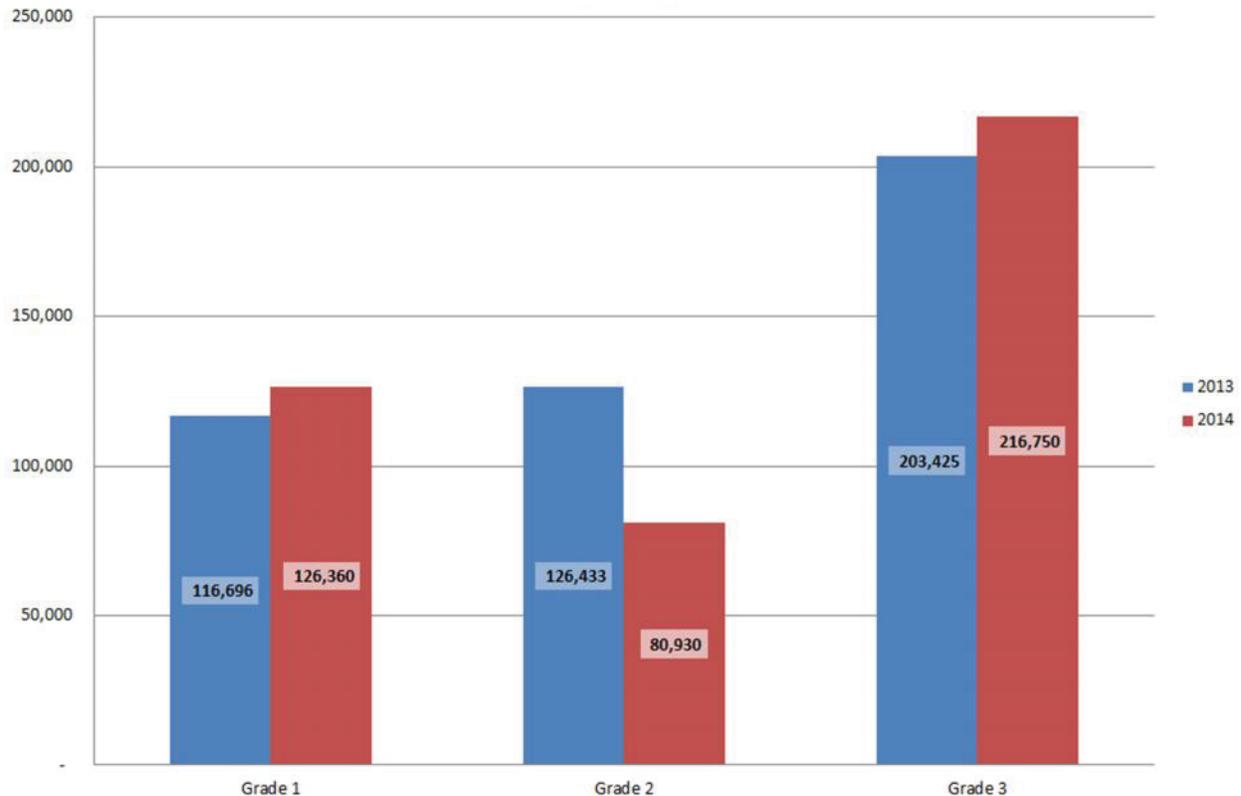


Figure 4 takes into account that some leaks emit more methane than other leaks. As discussed earlier in the report, one utility company stated that the number of grade 3 leaks greatly increased from 2013 to 2014 due to the higher sensitivity and more rapid detection of new leak detection equipment. The new equipment uses infra-red cameras, lasers, and ring down spectroscopy devices (e.g., Picarro) to identify leaks. This trend is expected to continue.

Figure 4 reflects the volume of graded leaks reported by utilities, and any leaks reported that were not graded were omitted for consistency purposes. Some utilities reported a zero emission amount when the leak was repaired on the date discovered. Staff did not try to correct for this apparent discrepancy (e.g., a leak by definition would have emissions of some volume). In some cases the imbedded formulas were complex and difficult to unravel and we could not determine whether the zero emissions was a result of formulaic issues or intentional.

In general, staff attributes the increase in leak volume in grades 1 and 3 to increased leak detection efforts where the leak repair rate has not kept up. The dramatic decrease in grade 2 leak volume appears to correlate to increased efforts to reduce the time to repair outstanding leaks.

**Figure 4: Volume of Graded Leaks 2013 and 2014 (Mscf)**



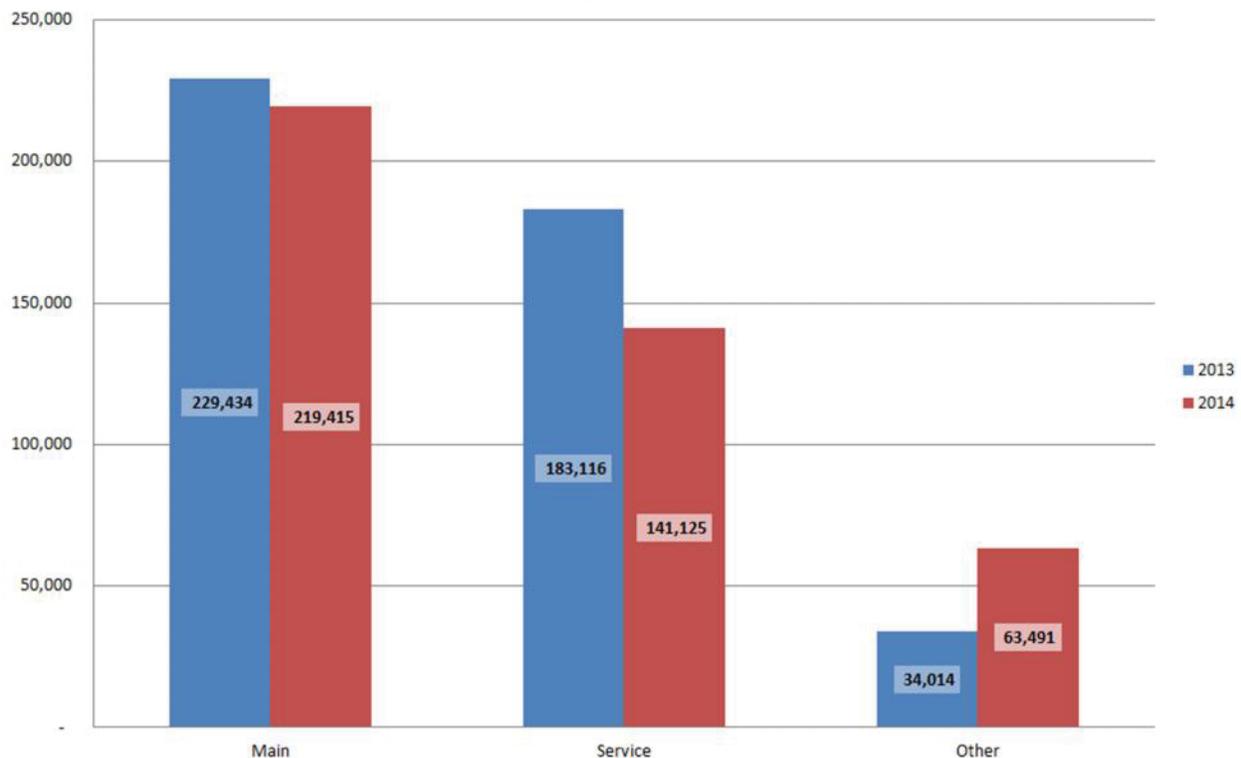
The graded leak data were also analyzed to determine the volume by pipeline type. Figure 5 shows that roughly half of the leaks are from distribution mains and half from services. Distribution mains pipelines are typically larger in diameter than distribution service pipelines and serve as conduits for the natural gas to flow too many service lines that connect to meter set assemblies. Future reporting will separate these categories to better understand the sources of leakage.

The total volume shown in Figure 5 differs from the graded leak volume due to the addition of a small amount of ungraded leak volume included in this chart. Staff used the reported category totals if easily determined, and where not easily determined, staff categorized mains as pipelines with 1" and greater diameter, and service as pipelines

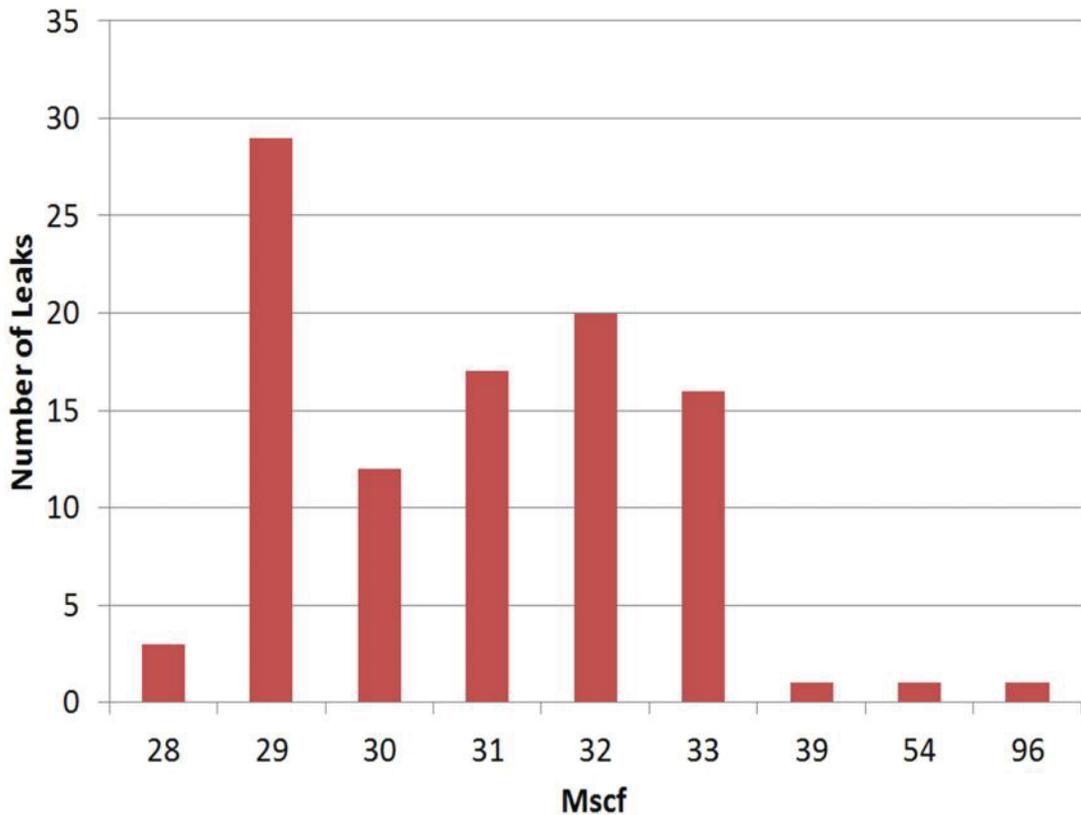
with less than 1" diameter. Staff included items that did not fall into main and service categories into the "Other" category.

The data show that both mains and services had a significant decrease in leak volume from 2013 to 2014. The Other category shows a marked increase, which in large part has to do with damages resulting in above ground leaks and the overall increase in efforts to detect leaks.

**Figure 5: Volume of Leaks by Category  
2013 and 2014  
(Mscf)**

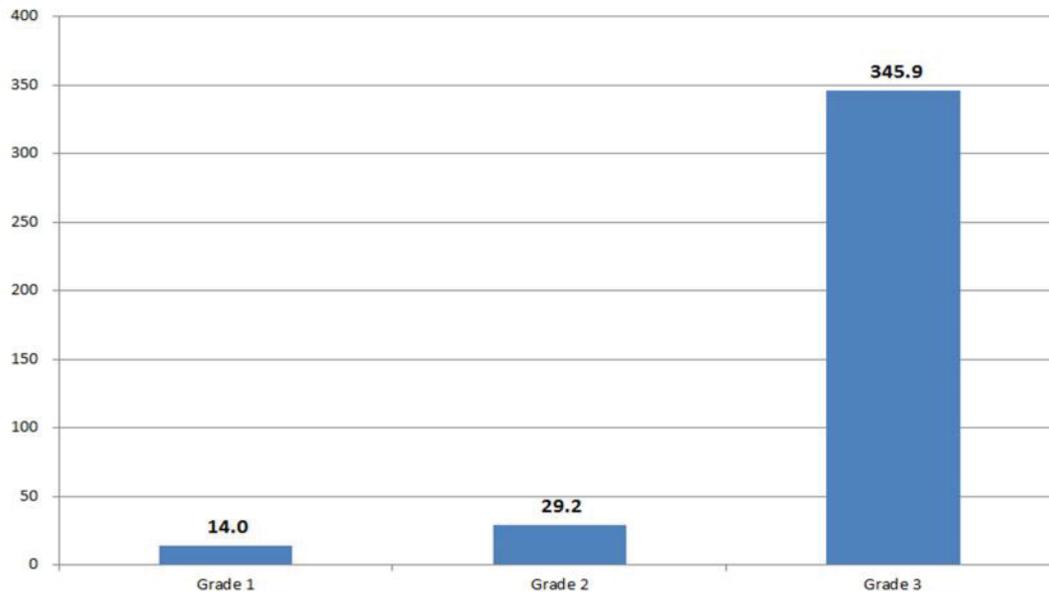


In addition to grouping the graded leak data, the data was sorted to list the 100 largest graded leaks reported in 2014. Figure 6 shows that majority of the large leaks fell within the range of 28 to 33 Mscf. There are three outliers that emitted volumes of 39, 54, and 96 Mscf. It is important to note that the majority of these leaks are based on emission factors, and not direct measurement.

**Figure 6: 100 Largest Graded Leaks Reported in 2014**

Finally, each leak included a date of discovery and date of repair along with its grade. The utilities' graded data was combined to determine the average number of days to repair graded leaks in 2014. Figure 7 shows that, on average, grade 1 leaks were repaired in two weeks, grade 2 leaks were usually repaired in less than a month and grade 3 were repaired in under a year. These results were consistent with the general definitions of graded leaks that are being repaired within this timeframe.

Figure 7 shows the average days to repair. Staff did not include leaks which had an indefinite scheduled repair date or a hypothetical default repair date (e.g., 15 months). Staff focused on the actual reported time to repair leaks because we did not want to skew the averages based on indefinite or hypothetical repair dates. Also, some utilities showed zero days to repair a leak when the leak was repaired in the same day, and did not reflect the fractional day or time to repair. Therefore, the average days to repair are skewed lower, and potentially could be less than "one" for an individual reporting entity.

**Figure 7: Average Days to Repair Graded Leaks in 2014**

For the most part the grade 1 leaks are repaired within 10 days with a vast majority within 2 days; however several prior year leaks that were repaired in 2014 drove the average up. A similar situation is true for grade 2 leaks.

The average days to repair grade 3 leaks would be most affected by indefinite or hypothetical default repair date because there is no requirement to repair grade 3 leaks and could go on forever. As a result the average days to repair grade 3 leaks only reflect the average for those grade 3 leaks repaired. There are a significant number of grade 3 leaks carried over from year to year.

It appears utilities stepped up efforts to increase the number of grade 3 leaks repaired as evidenced in the decreasing number of open grade 3 leaks in Figure 3 above. However, the more difficult and costly to repair grade 3 leaks would be more likely to be carried over from year to year.

The data on system-wide leak rates was limited and inconsistent so it was not appropriate to perform the calculation. CPUC and ARB may host a workshop to discuss this calculation.

## Lessons Learned

1. In some cases, summary respondent summary report totals could not be traced and validated to the underlying source data provided. For example, in some cases, it appears that embedded algorithms were used to summarize leak and emissions data that was brought forward to a summary sheet making it virtually impossible to tie totals to the underlying detailed support.
  - a. All algorithms used to locate, parse, subtotal or count underlying raw data tables should be transparent and adequately disclosed (even in cases where there is verbal explanation, the actual algorithm should be simply transparent to prevent totals that do not jibe with the described logic).
2. Discrepancies between the underlying data and summarized data reported occurred.
  - a. Provide a transparent link (such as a label or index identification) between subtotal or total on a supporting schedule that can be traced to the summary schedule.
  - b. Where subtotals or supporting totals are provided show how derived to support the validation of those totals.
3. Different definitions and approaches used by utilities increased the difficulty in making “apples to apples” comparisons of the information.
  - a. Develop and promulgate standard definitions for categorizing data and presenting data that align with reporting goals and objectives.
4. Some utilities used calendar year and some used fiscal July thru June as a basis for gathering and reporting their data. Staff used the 12 month data submitted to provide a reasonable approximation of annual emissions.
  - a. Going forward consensus on the reporting period must be achieved, reiterated to all parties, and then consistently applied to ensure integrity of the reported data.
5. Some utilities combined all their data comprised of more than one year into one table, and others broke their data into one table (e.g., Excel spreadsheet) per year. In either case, whether combining multiple years in one table or multiple tables of one year each, made it difficult, if not impossible, to reconcile the raw underlying data to the summary totals.

- a. When breaking the data into several one year data tables a separate summary table should be provided which shows the accumulation of information from each annual table that corresponds to the reported total.
- b. When using one table for all information, the respondent should provide a simple grouping within the table that shows the detailed contents of each subtotal and total. Or some other mechanism should be used to substantiate that the period data has been properly accumulated into the subtotals reported separately on another sheet.

## **Pending Data Request**

In November and December 2015, ARB staff worked with stakeholders to develop a new template to collect data for all equipment emission source categories. While the new template will continue to collect data for graded leaks, it will also require utility companies to report data for: transmission compressor stations, transmission pipeline, underground storage, transmission M&R, distribution M&R, and customer meters (residential, commercial & industrial).

Also, subject to further review by ARB and CPUC, the new template will require data for a number of categories that may be used to calculate a system-wide leak rate, such as transmission volume, distribution volume, purchased gas, produced gas, transported gas, etc. The new template will include a list of standardized emission factors that were developed to harmonize with the ARB's Mandatory Reporting Requirement, U.S. EPA, and others. Also, the template for the activity data has been expanded to include more items such as compressors, transmission M&R stations, pneumatics, and other emission source equipment.

(End of Attachment 1)