

Decision 17-06-015 June 15, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Adopt
Rules and Procedures Governing
Commission-Regulated Natural Gas Pipe
Lines and Facilities to Reduce Natural Gas
Leakage Consistent with Senate Bill 1371.

Rulemaking 15-01-008
(Filed January 15, 2015)

**DECISION APPROVING NATURAL GAS LEAK ABATEMENT PROGRAM
CONSISTENT WITH SENATE BILL 1371**

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Appendix A - Definitions

Appendix B - Best Practices for Minimizing Methane Emissions

**DECISION APPROVING NATURAL GAS LEAK ABATEMENT PROGRAM
CONSISTENT WITH SENATE BILL 1371**

Summary

This decision establishes best practices and reporting requirements for the California Public Utilities' Commission (Commission or CPUC) Natural Gas Leak Abatement Program that were developed in consultation with the California Air Resources Board (ARB), pursuant to Senate Bill (SB) 1371 (Leno, Chapter 525, Statutes of 2014), as set forth in Pub. Util. Code §§ 975, 977, 978. In order to minimize natural gas emissions from California's regulated transmission and distribution gas system, this decision implements the following:

1. Annual reporting for tracking methane emissions;
2. Twenty-six mandatory best practices for minimizing methane emissions pertaining to policies and procedures, recordkeeping, training, experienced trained personnel, leak detection, leak repair, and leak prevention;
3. Biennial compliance plan incorporated into the utilities' annual Gas Safety Plans, beginning in March 2018; and
4. Cost recovery process to facilitate Commission review and approval of incremental expenditures to implement best practices and Pilot Programs and Research & Development.

Actions taken in this decision support California's goal to reduce methane emissions 40% below 2013 levels by 2030 (SB 1383, Lara, Chapter 395, Statutes of 2016).

The CPUC and ARB will continue to collaborate on policies to achieve the state's greenhouse gas emission reductions goals.

Rulemaking (R.)15-01-008 shall remain open to address implementation issues in a second phase.

1. Background

On January 22, 2015, the Commission opened Order Instituting Rulemaking (R.) 15-01-008 (OIR) to implement the provisions of Senate Bill (SB) 1371 (Statutes 2014, Chapter 525).¹ SB 1371 requires the adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipeline facilities consistent with Pub. Util. Code § 961(d), § 192.703(c) of Subpart M of Title 49 of the Code of Federal Regulation, the Commission's General Order (GO) 112-F, and the state's goal of reducing greenhouse gas (GHG) emissions. SB 1371, which became effective January 1, 2015, added Article 3 to the Public Utilities Code² and consists of §§ 975, 977, and 978. Among other things, SB 1371 also requires the gas corporations to file an annual report about their natural gas leaks, and their leak management practices. In relevant part,

§ 975(e)(4) states that the Commission shall:

Establish and require the use of best practices for leak surveys, patrols, leak survey technology, leak prevention, and leak reduction. The commission shall consider in the development of best practices the quality of materials and equipment.

The OIR affirmed that the Rulemaking consists of two parts including 1) Respondents' filing of an annual report template that includes information described in § 975 (c);³ and 2) solicitation of input from utilities and other

¹ See 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," issued January 22, 2015.

² Unless otherwise stated, all code section references are to the Public Utilities Code.

³ Respondents in this proceeding include Alpine Natural Gas Operating Company No. 1 LLC; Pacific Gas and Electric Company; San Diego Gas & Electric Company; Southern California Gas

Footnote continued on next page

interested persons on what rules and procedures should be adopted by the Commission to reduce methane emissions.⁴

In Section 1(e) of SB 1371, the Legislature declares, among other things, that “Reducing methane emissions by promptly and effectively repairing or replacing the pipes and associated infrastructure that is responsible for these leaks advances both policy goals of natural gas pipeline safety and integrity and reducing emissions of greenhouse gases.”

The rules and procedures to be adopted must meet all of the following six principles as set forth in § 975(e):

- (1) Provide for the maximum technologically feasible and cost-effective avoidance, reduction, and repair of leaks and leaking components in those commission-regulated gas pipeline facilities that are intrastate transmission and distribution lines within a reasonable time after discovery, consistent with the California Global Warming Solutions Act of 2006 (Division 25.5 (commencing with Section 38500) of the Health and Safety Code) to achieve the goals in subdivision (b).
- (2) Provide for the repair of leaks as soon as reasonably possible after discovery, consistent with established safety requirements and the goals of reducing air pollution and the climate change impacts of methane emissions.
- (3) Evaluate the operations, maintenance, and repair practices of those commission-regulated gas pipeline facilities that are intrastate transmission and distribution lines to determine whether existing practices are effective at reducing methane leaks and promoting public safety, consistent with Section 961, achieve the goals of subdivision (b), and whether alternative

Company; Southwest Gas Corporation; West Coast Gas Company; Central Valley Gas Storage, LLC; Gill Ranch Storage, LLC; Lodi Gas Storage, LLC; and Wild Goose Storage Inc.

⁴ OIR at 8-10.

practices may be more effective at achieving the goals of subdivision (b).

- (4) Establish and require the use of best practices for leak surveys, patrols, leak survey technology, leak prevention, and leak reduction. The commission shall consider in the development of best practices the quality of materials and equipment. Collected leak data shall remain the property of the utility and shall be available to the commission and parties in commission proceedings as determined by the commission or specified by statute.
- (5) Establish protocols and procedures for the development and use of metrics to quantify the volume of emissions from leaking gas pipeline facilities, and for evaluating and tracking leaks geographically and over time, that may be incorporated into the plans required by § 961, or into other state emissions tracking systems, or both, including the regulations for the reporting of greenhouse gases of the State Air Resources Board. The quantification of emissions shall provide operators, the commission, and the public with accurate information about the number and severity of leaks and about the quantity of natural gas that is emitted into the atmosphere over time.
- (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, along with any data and computer models used in making that calculation, and to annually report on measures that will be taken in the following year to reduce the system wide leak rate to achieve the goals of subdivision (b).

In response to the statutory requirements of SB 1371 and R.15-01-008, the Safety and Enforcement Division (SED) developed a report entitled "Survey of Natural Gas Leakage Abatement Best Practices" dated March 17, 2015 (Staff Report). Among other things, the Staff Report identified technologies and practices presently in use around the globe, technologies and practices which are

new and/or currently in use in California, and those which are in various stages of research and development (R&D). The report recognized that “all stakeholders, including the utilities and facility operators, have a responsibility to engage in identification of best practices and investment in R&D of new technologies.”⁵

The Staff Report contained some preliminary observations, recommendations, and conclusions regarding some of the best practices in the areas of definition of leaks, economic analysis of methane leak detection, leak grading and repair timelines, leak surveys, leak detection, leak prevention, information, training, and records. The assigned Administrative Law Judge (ALJ) entered the Staff Report into the record on March 18, 2015 and parties provided initial and reply comments on April 1, 2015 and April 22, 2015. This report, along with stakeholder comments on the report and an initial workshop, served as basis for developing a more precise scope for the proceeding.

2. Procedural Background

A Prehearing Conference (PHC) was held on June 8, 2015, in San Francisco to establish the service list, discuss the scope of the proceeding, review the categorization and need for hearing, and develop a procedural timetable for the management of this proceeding. At the PHC, parties requested the opportunity to file post-PHC comments regarding a preliminary draft of scoping questions and schedule presented to parties by the ALJ at the PHC. On June 26, 2015, comments were timely filed by: Southern California Gas Company (SoCalGas), San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company

⁵ Staff Report at 2.

(PG&E), and Southwest Gas Corporation (Southwest Gas) (collectively “Utilities”); Southern California Edison (SCE);⁶ Lodi Gas Storage L.L.C. and Central Valley Gas Storage, L.L.C.; Environmental Defense Fund (EDF); Coalition of California Utility Employees (CUE), The Utility Reform Network (TURN); and the Office of Ratepayer Advocates (ORA).

On July 24, 2016, the assigned Commissioner issued a Scoping Memo addressing the scope of the proceeding and other procedural matters, and establishing the procedural schedule.

2.1. Workshops

Consistent with the Order Instituting Rulemaking (OIR) directives and Scoping Memo objectives, SED Staff conducted the following workshops in cooperation with ARB:

- a. Workshop on May 15 Leak Reports (September 23, 2015) SED Staff organized and facilitated a workshop to review major issues from the initial reports and solicit ideas for improvements to future reports:
 - Current approaches used to estimate emissions including the system-wide gas leak rate equation;
 - Characterization of leaks and where they are located;
 - Quantification of methane emissions from distribution and transmission systems; and
 - How to improve future reporting.

⁶ In its post-PHC comments (at 1-2), SCE asked that it be removed as a respondent in this proceeding because it delivers propane, and not methane. Referring to the unique characteristics of SCE’s Catalina Gas Utility operations, SCE operates a “small, distribution only, relatively low pressure propane system on Catalina Island.”

b. Working Group Workshop on Best Practices (October 27, 2015)

Based on “target” emission sources, and best practices to identify, measure, avoid, and repair leaks, discuss:

- Best practices to identify leaks;
- Best protocols, methods and procedures to quantify methane emissions and leaks;
- Best preventive maintenance and operations practices to avoid and prevent leaks, emissions from blowdowns, operational emissions and other emissions, including third-party dig-ins; and
- Best practices to repair leaks (e.g., customer meters are a major source of leaks. What is a cost-effective way to repair those?)

c. CPUC/ARB Workshop on Targets, Compliance, and Enforcement (April 12, 2016)

Based on best means of determining emissions estimates, discuss:

- Determining and establishing targets;
- Means of reporting;
- Ability to comply; and
- Enforcement options.

d. CPUC/ARB Workshop on Cost Effectiveness (November 3, 2016)

- ARB proposed options for evaluating cost-effectiveness;
- Cost effectiveness and “CPUC Threshold;”
- Cost effectiveness in the context of impact on ratepayers; and
- Cost-benefit analysis where social benefits include quantification of avoided environmental damages.

- e. CPUC/ARB Workshop on Best Practices (December 12, 2016 and December 21, 2016)
 - Clarify revised best practices; and
 - Established realistic deadlines for implementation.
- f. ARB Hosted Workshop on Emission Factors (February 2, 2017)

Discussion of emission factors used for SB 1371 required methane emissions inventory annual reports including those from:

- 1996 Gas Research Institute (GRI)/U.S. Environmental Protection Agency (EPA) Study;
- 2015 Washington State University led Environmental Science and Technology published article “Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States;” and
- ARB-funded Gas Technology Institute (GTI) Report entitled “Quantifying Methane Emissions from Distribution Pipelines in California” dated December 2015.

As demonstrated below, parties had multiple opportunities to comment on “work in progress” throughout various stages of the first phase of this proceeding. A robust stakeholder process with many active parties characterized this proceeding throughout the first phase of this proceeding.

2.2. Annual Report Template and Joint Staff Report

In response to an SED Staff’s January 2015 data request, Respondents in the proceeding submitted initial reports on current gas leaks and leak management practices on May 15, 2015. Parties filed comments on SED’s format

and content of the report on October 30, 2015 and November 6, 2016. Based on feedback, parties provided another round of comments on newly revised annual reporting requirements on comments on February 17, 2016 and February 24, 2016. On February 24, 2016, the ALJ issued a ruling entering the California Air Resources Board and California Public Utilities Commission Joint Staff Report on the Analysis of the May 15, 2015 Utilities' Reports into the record and sought comments by March 18, 2016.

On April 11, 2016, using a newly revised annual reporting template, the ALJ issued a ruling regarding 2016 annual reporting requirements on current gas leaks and management responses and directed named Respondents' responses by June 17, 2016. Based on responses to the April 11, 2016 ruling and the data requests contained therein, Joint Staff developed a second annual report in January 2017, and parties provided comments on February 10, 2017 and February 17, 2017.

2.3. Parties' Comments

a. Cost-Effectiveness, Cost Recovery, and Cost Containment Considerations

On October 29, 2015, the ALJ requested comments on cost-effectiveness considerations and parties provided comments on November 20, 2015 and December 4, 2015 (questions #2, a-e). On December 1, 2016 the ALJ entered the November 3, 2016 cost-effectiveness workshop documents into the record and parties provided initial and reply comments on December 9, 2016 and December 22, 2016, respectively.

b. Best Practices (BPs)⁷

On March 24, 2016, the ALJ issued a ruling entering a summary of Best Practices Working Group activities and staff recommendations into the record and directed responses by April 22, 2016 and May 6, 2016.⁸ On May 6, 2016 and May 20, 2016, parties provided comments on staff recommended Best Practices. On November 21, 2016, the ALJ requested additional comments on Best Practices and Cost-Effectiveness. Based on May 2016 comments and December 2016 workshops, parties provided another round of comments on a second revised set of Best Practices on February 10, 2017, and February 17, 2017.

c. Targets, Compliance, and Enforcement

On June 23, 2016, the ALJ entered the Targets, Compliance, and Enforcement Workshop Summary and Materials on Targets, Compliance, and Enforcement into the Record and directed comments by July 15, 2016 and July 22, 2016. In response to motion served by EDF on August 19, 2016, parties were allowed another opportunity to provide supplemental comments on August 19, 2016.

3. Restatement of the Problem

Historical utility regulations view the primary issue with natural gas as the immediate safety hazard it presents when not managed properly. In view of the serious fatal accidents in California and elsewhere in the country, utilities have categorized and repaired leaks based on safety risks assessed grade “1,” “2,” or “3” leaks. As classified by General Order (GO) 112-F Section 143.2, a “Grade 1

⁷ In this decision, the terms “Best Practices” and “BPs” are used interchangeably.

⁸ Due dates for initial and reply comments were extended to May 6, 2016 and May 20, 2016.

leak” is a leak that represents an existing or probable hazard to persons or property and requires 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. 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. Unlike the first two categories of leaks, Grade 3 leaks do not need to be repaired and could be permitted to leak indefinitely. (CUE February 10, 2017 Comments at 3 citing Gas Piping Technology Committee, Guide for Transmission, Distribution, and Gathering Piping Systems, Leak Classifications and Action Criteria.)⁹

As SB 1371 makes clear, this business paradigm is no longer acceptable and a “new way of doing things” is required. In terms of managing natural gas, we need to look at not only policy goals of natural gas pipeline safety and integrity, but also reduction of greenhouse gases and their deleterious “real” consequences.

According to SB 1371:

There is a growing awareness of the potency of methane, the primary component of natural gas, as a greenhouse gas. The Intergovernmental Panel on Climate Change estimates that the global warming potential of methane is 28 times that of carbon dioxide over a 100-year time horizon. There is also a growing awareness that climate change impacts high social costs, including impacts upon public health and the economy.

⁹ See the CPUC GO 112-F for an expanded list of definitions. Also see Appendix A of this decision that lists definitions that staff and respondents used in the methane gas leaks annual reporting process.

Reducing methane emissions by promptly and effectively repairing or replacing the pipes and associated infrastructure that is responsible for these leaks advances both policy goals of natural gas pipeline safety and integrity and reducing emissions of greenhouse gases. (SB 1371, Section 1 (d)(e).)

4. Issues Before the Commission

Interested parties were provided an opportunity to provide input on the proceeding at the PHC and through post-PHC comments. According to the Scoping Memo, the first phase was designed to develop the overall policies and guidelines for a natural gas leak abatement program consistent with SB 1371 and included the following program development activities: 1) information gathering, measurement, and best practices; 2) targets, compliance, and reporting; and 3) training and enforcement. (OIR at 3.)

The second phase was designed to develop ratemaking and performance-based financial incentives associated with the natural gas leak abatement program. However, the content of a second phase is subject to change consistent with the priorities established by this decision. (*Ibid.* at 3.) (*See* Section 13 “Phase Two of the Proceeding.”)

5. Annual Report Requirements

5.1. SB 1371 Requirements

SB 1371 mandates that the Commission require the gas corporations to file a report with certain information. Specifically, § 975 (c) provides:

- (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:
 - (a) A summary of utility leak management practices;
 - (b) A list of new methane leaks in 2013 by grade;
 - (c) A list of open leaks that are being monitored or are scheduled to be repaired; and

(d) A best estimate of gas loss due to leaks. (OIR at 3-4.)

In response to this SB 1371 mandate, the rulemaking mandated two requirements, which are addressed in this decision.

First, pursuant to § 975(c), gas corporations shall file a report that includes the information described in § 975(c) and the OIR, which will allow the Commission to gather additional information about natural gas leaks, and how leaks are currently being managed and mitigated.^{10 11} This, in turn, will assist the Commission in the development and adoption of appropriate rules and procedures to minimize natural gas leaks and to reduce natural gas emissions from such leaks to advance the goal of reducing greenhouse gases.

The initial report to be filed by each of the respondent gas corporation, at a minimum, shall include the following information:

1. A description and general location of each gas corporation's gas pipeline facilities, including its intrastate transmission and distribution lines.
2. A summary of its current leak management practices.
3. A list of new methane leaks in 2013 and 2014, by grade.

¹⁰ Section 975(c) provides that "gas corporations" are required to file the report. Since the term gas corporation is defined in § 222 to mean "every corporation or person owning, controlling, operating, or managing any gas plant for compensation within this state," and because "gas plant" is defined in § 221 to include "all real estate, fixtures, and personal property, owned, controlled, operated, or managed in connection with or to facilitate the production, generation, transmission, delivery, underground storage, or furnishing of gas ... for light, heat, or power," all of the above-named respondents are required to file this report.

¹¹ Section 975 (e)(6) requires 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, along with any data and computer models used in making that calculation, to periodically update that system wide leak rate calculation, and to annually report on measures that will be taken in the following year to reduce the system wide leak rate to achieve the goals of subdivision (b).

4. A list of open leaks that are being monitored or are scheduled to be repaired. If the open leak is only being monitored, provide the reason(s) why the leak has not been scheduled to be repaired must be provided.
5. The total number of leaks detected and repaired in 2013 and 2014, and the time it took to repair those leaks once they were discovered.
6. A best estimate of gas loss due to leaks (list estimated gas loss by month for 2013 and 2014), and an explanation of how the estimates were derived. (OIR at 8-9.)

The second requirement of the rulemaking is to obtain input from utilities and other interested persons on what rules and procedures should be adopted by this Commission to fulfill other requirements of SB 1371. As set forth in § 975(e), rules and procedures must, among other things, be maximally technologically feasible, consider cost effectiveness, and use Best Practices. This is addressed in Section 6 “Criteria to Evaluate Procedures” and Section 7 “Best Practices.”

In addition to the single report required by § 975(c), § 975(e)(6) obliges the Commission to require respondents to “annually report on measures that will be taken in the following year to reduce the system wide leak rate to achieve the goals of [reducing emissions to the maximum extent feasible to achieve the State’s emission reduction targets].”

Natural gas operators submitted annual reports in 2015 and 2016 and will submit their latest version in June 2017. These operators included large and small gas utilities (utilities), and independent storage providers (ISPs). The data in the reports were separated into seven system categories:

- Transmission Pipelines (leaks, damages, blowdowns, components, and odorizers);
- Transmission Metering and Regulation (M&R) stations (leaks, blowdowns, and components);

- Compressor stations (compressor leaks and emissions, blowdowns, components, and storage tanks);
- Distribution Pipeline Mains and Services (leaks, damages, blowdowns, and components);
- Distribution M&R stations (leaks and emissions, and blowdowns);
- Customer Meters (leaks, and venting); and
- Underground Storage Facilities (leaks, compressors leaks and emissions, blowdowns, components, and dehydrators).

The Commission notes that SB 1371 requires efforts to address “leaks,” as defined in Appendix A, include “ungraded” or “nongraded” leaks, as well as “vented emissions” which may occur during various operations and may release methane from components, other than pipelines, that are part of the gas system. For example, § 975 (e)(1) gives direction to: “Provide for the maximum technologically feasible and cost-effective *avoidance, reduction, and repair of leaks and leaking components* in those commission-regulated gas pipeline facilities ...” The statute also notes the need to reduce methane emissions by “promptly and effectively repairing or replacing *the pipes and associated infrastructure* that is responsible for these leaks” (§ 1(e) of SB 1371). Accordingly, the reporting protocols and best practices apply to all sources of methane emissions from the utilities’ gas system, including leaks, vented emissions, and fugitive emissions.¹²

¹² Fugitive emissions are emissions of natural gas from pressurized equipment due to leaks and other unintended or irregular releases from pressurized process equipment, which generally occur through valves, pipe connections, mechanical seals, or related equipment.

As defined in the third annual reporting template that was distributed on April 4, 2017, relevant definitions are attached in Appendix A.¹³

5.2. Joint Staff Revised Annual Reporting Framework

In collaboration with parties, SED and ARB Staff expanded upon the OIR suggested general framework identified above and developed the following enhanced framework:

- (1) A summary of changes to utility leak and emission management practices from January 1 through December 31 of the previous calendar year. The report must include a detailed summary of changes, including the reasoning behind each change and an explanation of how each change reduces methane leaks and emissions.
- (2) A list of new graded and ungraded gas leaks discovered, tracked by geographic location in a GIS or best equivalent, by grade, component or equipment, pipe size, schedule and material, pressure, age, date discovered and annual volume of gas leaked for each, by month, from January 1 through December 31 of the previous calendar year.
- (3) A list of graded and ungraded gas leaks repaired, tracked by geographic location in a GIS or best equivalent, by month, from January 1 through December 31 of the previous calendar year. Include the grade, component or equipment, pipe size, schedule and material, pressure, age, date discovered, date of repair, annual volume of gas leaked for each and the number of days from the time the leak was discovered until the date of repair completion.

¹³ For more explanation and detail, please *see* 49 CFR 192.3, PHMSA Form F7100.1-1 (rev.-2015), and GO 112-F. Parties had multiple opportunities to comment on these definitions throughout the proceeding.

- (4) A list of ALL open graded and ungraded gas leaks, regardless of when they were found, tracked by geographic location in a GIS or best equivalent that are being monitored, or are scheduled to be repaired, by month, from January 1 through December 31 of the previous calendar year. Include the grade, component or equipment, pipe size, schedule and material, pressure, age, date discovered, scheduled date of repair completion, and annual volume of gas leaked for each.
- (5) System-wide gas leak and emission rate data, along with any data and computer models used in making that calculation, for the 12 months ending December 31, of the reporting year.
- (6) Calculable or estimated emissions and leaks for the 12 months ending December 31 of the reporting year, using the categories, emission factors (EFs) and activity factors in the appendices sent with this [annual] data request.
- (7) An annual report on measures that will be taken in the following year to reduce leaks and emissions to achieve the goals of SB 1371. The report must include a detailed summary of changes, including the reasoning behind each change and an explanation of how each change will reduce methane leaks and emissions. (ALJ April 4, 2017 Ruling at 7-8.)

5.3. Joint Staff Evolving Spreadsheet Template

Based on parties' feedback and CPUC and ARB staff recommendations, the Spreadsheet Template that accompanies the Staff Annual Reporting Framework, continues to evolve. On January 26, 2016, the ALJ issued a ruling seeking comments on a proposed newly revised annual data request and report template with the following differences:

- Adjusted the baseline report year, for comparison purposes, to 2015.¹⁴
- Changed the reporting year from Fiscal year to Calendar year for all information including the system leak rate.
- Added the requirement to report all open leaks no matter when they were found.
- Added a column to report leaks by location (zip code, GIS, or equivalent).
- Added a column to report the material of the leaking component.
- Added a spreadsheet for leaks caused by third parties or nature.
- Added columns for the date of temporary leak repairs and time to temporarily repair them.¹⁵
- Added a row for report emissions caused by catastrophic failures such as pipeline or storage well failures.
- Added a column to indicate whether a leak was Above Ground or Below Ground.
- Added more definitions of terms, consistent with Pipeline and Hazardous Materials Safety Administration (PHMSA), where applicable.
- Improved System Wide Leak Rate calculation.
- Added Standardized EFs.

¹⁴ Parties filed comments on October 30, 2015 in response to an October 27, 2015 ruling seeking comments on establishing 2015 as the baseline year. Parties recommended using 2015 as the baseline to rectify inconsistency and incompleteness in the 2013/2014 reported data: 1) entities reporting on either calendar or fiscal year; 2) no consistent application of emission factors; 3) lack of consistent use of activity factors; and 4) different interpretations on how to calculate system-wide leak rates. Revised reporting templates and instructions corrected these issues for 2015 data reporting.

¹⁵ This change was implemented in 2016 annual reporting templates. It is not used in the calculation of estimated emissions and was subsequently dropped in the 2017 annual reporting templates.

Based on the second round of parties' comments and Joint Staff recommendations, additional changes were made to the annual data request and annual reporting template for 2015 emissions data. The 2014 information received from stakeholder filings revealed that the information request needed incremental improvements. Specifically, more work needed to be done to quantify leak volume, validate and update EFs to consistently approximate category population emissions, and increase the confidence in the methods that would ensure consistent and comprehensive reporting across utilities.

The data request for 2015 emissions data included a request for more detailed component emissions data, and required 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. 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 revised and improved templates resulted in a more consistent record of emission estimates for 2015. However, incremental improvements of the template need to occur over time as new information is gained. For example, Staff did not originally contemplate that all utilities were not uniformly counting emissions from leaks that occur in the utility's un-surveyed service territory. The methods developed in the summer of 2016 were incorporated into the reporting templates issued in 2017 to report 2016 emissions data.

In addition, both staff and parties agree that greater reliance on scientifically based measurements and readings of actual leaks needs to occur in order to determine whether emissions reductions actually occur. Currently 2014 and 2015 annual emission reports used a mixture of estimation methods, such as population counts times EF, leak detection, direct measurement and engineering estimates. Over time, EFs will be reviewed and updated based on improved information. (See “Discussion” section, below, for more information on this topic.)

5.4. Joint Staff Annual Report Findings

The following is a summary of Joint Staff findings based on reports published on February 22, 2016 and January 19, 2017.

5.4.1. 2016 Joint Staff Report based on 2014 Emissions Data

Staff originally believed that the largest source of emissions was from unrepaired Grade 3 pipeline leaks deemed non-hazardous under PHMSA criteria. However, further ARB and CPUC analysis revealed two significant sources of leaks that accounted for about 89% of the estimated leakage:

- 1) Vented emissions: This results during maintenance when gas is blown to the atmosphere to reduce pressure and make it safe to work on the pipe segment or components; and
- 2) Ungraded leaks: The Meter Set Assembly (MSA) or essentially the riser connection to the meter was a major source of emissions.¹⁶ In 2014 ungraded leaks included blowdowns, damages, equipment and component, storage and M&R station leaks.

¹⁶ MSAs refer to customer meters (either commercial, industrial or residential) comprised of a meter for reading gas throughput and pressure regulator.

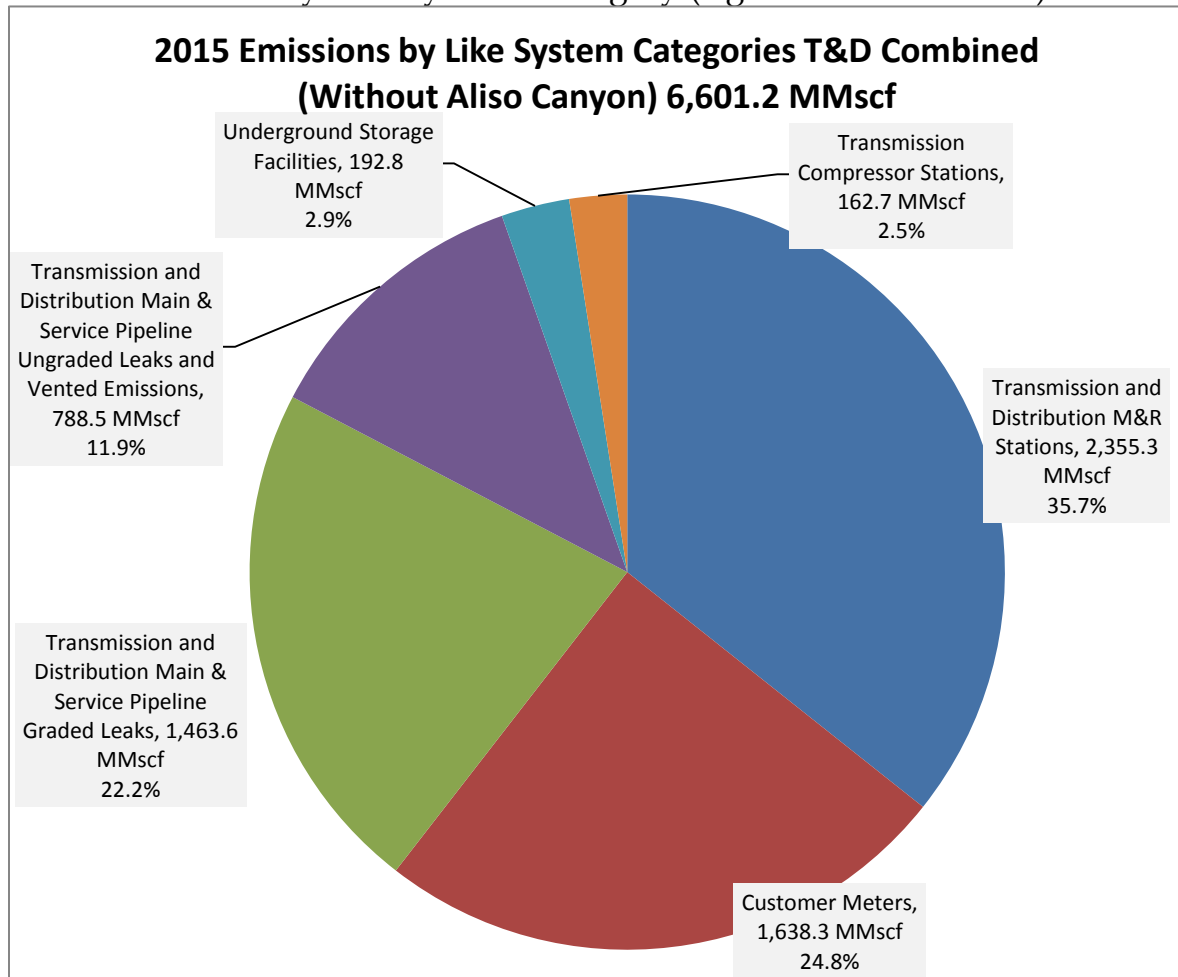
5.4.2. 2017 Joint Staff Report based on 2015 Emissions Data

The 2015 emissions data continues to reveal that although the graded leaks are significant, the ungraded leaks and associated emissions make up the largest subset of emissions reported. Together, 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. This proportion is significantly less than the 89% reported based on 2014 data. This can be attributed to improved data collection efforts including the tallying of above ground and below ground leaks, uniform EFs to ensure consistency between operator data and greater rigor imposed on the calculation of emissions from blowdowns. The graded leaks volume makes up 22% and almost exclusively represent distribution leak volumes.

Breakdown of the ungraded leaks (78%) versus graded leaks (22%) is as follows:

1. M&R stations (both transmission 15.3% and distribution 20.4% combined), 35.7%;
2. Customer MSAs, 24.8%;
3. Ungraded leaks and vented emissions of 11.9% in the combined Transmission (8.2%) and Distribution (3.7%) pipeline systems (omitting the 22.2% for graded leaks);
4. Compressor stations, 2.5%; and
5. Underground storage facilities (without Aliso Canyon) 2.9%.

Emissions by Like Systems Category (e.g. All M&R stations.):¹⁷



In this chart, both the Natural Gas Transmission and Distribution (NGT&D) 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 sources other than pipeline graded leaks.

¹⁷ 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.

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. Although 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. By separating out and combining the emissions by the source activity, such as all blowdowns together, or station facilities, or compressors no matter where they are located, it is easier to see emissions from like activities and systems.

5.4.3. Global Warming Potential – Putting the Emissions into Context

The following table shows the total emissions reported for 2015 (excluding the Aliso Canyon Storage leak) for ungraded leaks and vented emissions, and pipeline graded leaks in million standard cubic feet (MMscf) of natural gas, metric tons of methane as well as the carbon dioxide equivalent (CO₂e) using the 100- and 20-year Global Warming Potential (GWP) values of the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (AR4).

The Global Warming Potential in Various Equivalent Metrics:¹⁸

¹⁸ EPA GHG equivalency calculator derived amounts (<https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator>) using a 100-year GWP multiplier of 25 (million metric tons of carbon dioxide equivalent – MMTCO₂e).

	MMscf	Metric Tons CH ₄	100 Year GWP MMTCO ₂ e	20 Year GWP MMTCO ₂ e
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.¹⁹ (See Appendix D of the Joint Staff Report for details on how the CO₂e was calculated.)

According to the 2017 Joint Staff Report, the baseline emissions estimate for 2015 from SB 1371 sector utilities totals 6,601.2 MMscf, which provides a starting point to measure future natural gas emissions reductions. These emissions are equal to 2.96 million metric tons of carbon dioxide equivalents (MMTCO₂e) using the 100-year methane GWP (25) or 8.51 MMTCO₂e 20-year methane GWP (72).

5.5. Parties' Comments

5.5.1. Accurate Trends in Annual Report?

In response to the Joint Staff Annual Report published on January 19, 2017, parties generally agreed that the report provides a credible assessment of trends. According to PG&E, the Joint Staff Annual Report “provides an accurate depiction of the emission trends observed by PG&E. The top four natural gas

¹⁹ EPA's GHG calculator shows that 118,226 mttCH₄ equates to 332.6 mm gallons of gasoline, or 7,083 mm 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>.

utility emission source categories identified for California are aligned with PG&E's reported distribution pipeline leaks, customer meter set leaks, and distribution and transmission measurement and regulation ("M&R") stations." (PG&E February 10, 2017 Comments at 1-2.) SoCalGas and SDG&E appreciate that the Joint Staff Annual Report accounted for the differences in the reporting templates between 2015 and 2014 and did not develop conclusions based on the two years. They acknowledge the report clarifies differences in the SB 1371 versus traditional PHMSA approaches to define a "Leak" and to calculate "Unaccounted For" volumes in the Joint Staff Annual Report. "This clarification helps explain the significant differences in scope involved with this rulemaking in comparison to other reported data." (SoCalGas and SDG&E February 10, 2017 Comments at 2.)

Despite acceptance of identified trends, SoCalGas cautions that "while the 2015 reported emissions can be used to provide a baseline to gauge reduction efforts going forward, it is possible that as emissions factors are refined, the estimates made in 2015 may not be reasonable to establish a baseline and may need adjustment." SoCalGas and others are concerned that utilities and storage operations must have a means for gaining credit for their continued progress over the years to reduce methane emissions and this effort should not be undermined by any distortions in emissions reductions caused by EFs. (SoCalGas February 10, 2017 Comment at 3.)

EDF claims that the Joint Staff Annual Report can and should be edited in three specific areas to make its conclusions more clear, and yield a better ability to identify and track trends.

First, the report does not specify how each utility's emissions contribute to the different categories of leaks – instead aggregating data across all utilities and limiting the ability to compare one to

another. Second, the report converts totals into the carbon dioxide equivalent when methane should be analyzed on its own. Third, the definition section does not include all categories of leaks that utilities use, therefore it is unclear whether the emissions were placed in the proper category. (EDF February 10, 2017 Comments at 2.)

According to EDF, in 2016 PG&E posted all of its public data, and all of the annual report templates in response to EDF's request. Sempra utilities only posted their written report (questions 1 and 7) and summary tables (Appendix 8), even though they had public versions of the templates available. To remedy these issues, EDF proposes that the Commission should state in the annual report data request that the utilities are also required to post public versions of their entire reports on the website like the gas safety plan, or on the websites of the individual regulated utilities. The public versions should include all templates and all data points that are not confidential. (*Ibid.* at 6, 8.) The utilities have interpreted the data required in different manners, making review and comparison by the parties difficult.

5.5.2. Lessons Learned

In the 2017 Joint Staff Annual Report, ARB and the CPUC stated that significant effort has gone into revising templates over time since the first one was issued in January 2015. But more work needs to be done "in quantification of leak volumes, validating and updating EFs to better approximate category population emissions, and increasing confidence in the methods that would ensure consistent and comprehensive reporting across utilities." (Joint Staff Report, January 17, 2017 at 31). PG&E agrees and states:

It is critical to continue to refine the technology, methods, and emissions factors used to develop annual reports. Better measurements and estimates can help operators accurately identify sectors where additional emission reduction strategies should be

applied, and incorporate these measures into their compliance plans. (PG&E February 10, 2017 Comments at 3. *See discussion.*)

SoCalGas and SDG&E point out that natural gas emissions from various aspects of the grid (i.e., Transmission, Storage, and Distribution) are complex and varied as to the source, category, cause, and intent. According to SoCalGas and SDG&E, “[c]ategorization should take into account the historic approach to the design of the various pipeline systems and components as well as the nature of the vast network of facilities with portions varying on age.” (SoCalGas and SDG&E February 10, 2017 Comments at 3-4.)

In addition, “estimating emissions is a function of both the available system information and the scope and approach on industry studies that have developed the various emission factors.” “A clear understanding of the application of each individual emission factor is required to obtain the correct result.” Various factors are considered including facility types, individual component types, leaking and non-leaking components, population-based factors, and engineering estimate methodologies, etc.” They argue that “whether or not direct measurement methods will yield a better estimate is a function of many factors and may need additional analysis.” (SoCalGas and SDG&E February 10, 2017 Comments at 4.)

The ISPs suggest that they should not be considered in the “same league” as other respondents for reporting purposes. For example, in addition to not sharing the same business model, they suggest that the reporting data and analysis show that ISPs are very minute or “de minimis” sources of statewide methane emissions. “Thus, regulatory mandates which would force ISPs to implement uneconomic measures to meet compliance targets would not result in meaningful contributions to reducing statewide emissions.” (ISPs February 10,

2017 Comments at 3.) They contend that “compared with the data that the ISPs reported to the CPUC in 2016, ISPs in total emit less than ½ of one percent of all reported gas utility methane emissions.” (*Ibid.*) “This amount is even less significant when all methane sources are included – in that case, ISPs emit about three hundredths of one percent of the statewide total.” (*Ibid.*)

According to ISPs, instead of seeking to reduce statewide emissions by having it attempt to make extremely expensive changes that would not provide a noteworthy reduction of emissions, the data in the report show other emission categories where incremental investments can be made much more effectively.

For example:

- Transmission pipeline blowdowns reported by the utilities emit 15 times as much gas as all of the ISP emissions combined.
- Graded distribution leaks emit 48 times as much gas as all of the ISP emissions combined.
- Distribution customer meter set leaks are estimated to emit 54 times as much as all of the ISP emissions combined. (*Ibid.* at 4.)

The ISPs conclude that reducing emissions from the above three sources by just an additional 1% (i.e., targeting a 41% reduction for these items rather than a 40% reduction) would prevent more gas emissions statewide than the ISPs currently emit in total. (*Ibid.*)

According to EDF, it identified a few issues with the current report that were missed in their explanation of lessons learned. “Currently, it is EDF’s understanding that utilities do not track and record all the data that ARB and the Commission deem to be relevant. Accordingly, there should be an introduction clause that requires the utilities to track all the data included in the categories in the reporting templates.” (EDF February 10, 2017 Comments at 5-6).

Based on the Joint Staff Annual Report, EDF believes the agencies identified the majority of the issues and lessons learned from last year's report. EDF specifically agrees with the conclusions that "going forward the emissions estimation methods should be reviewed periodically to continually improve the emission estimates going forward." EDF concludes that more emphasis needs to be placed on finding ways to quantify emissions." (EDF February 10, 2017 Comments at 5.)

Similarly, "Southwest Gas believes the effect of EFs on the data reported and on the measurement of future emissions reductions cannot be understated." For example, "in the absence of a scientific tool that can be used to measure actual leak volumes, the parties must rely on either sound engineering estimates or EFs to calculate the estimated methane emissions from a particular source." (Southwest Gas February 10, 2017 Comments at 3-4.) Southwest Gas agrees with staff that some of the EFs relied upon for the June 2016 reports are outdated and may have overstated emissions from various infrastructure sources, including M&R stations, compressor facilities and MSA, and encourages ARB and SED to maintain their focus on revising and updating the EFs." (*Ibid.* at 3-4.)

5.5.3. Ongoing Template Changes

Based on lessons learned by Joint Staff during the report generation process, as well as responses to issues raised in parties' comments on February 10, 2017 and February 17, 2017, and ongoing Joint Staff discussions with Respondents, changes were made to the annual data request and 2017 Annual Reporting Template. Among other things, a worksheet was added to the annual reporting template such that the compressor and component tabs now have a tab for their fugitive emissions and another tab for their emissions. Parties suggested that by design and function some compressors and

components emit natural gas. A fugitive leak may be fixed but the design and functional features generally cannot be made leak-free.

The annual reporting template, since its original framework was published in SB 1371 and subsequent OIR, has undergone significant changes through a robust stakeholder process and continually improved versions. We expect this spirit of “continuous improvement” to the reporting process and development of related metrics. Using the April 4, 2017 Annual Ruling/Data Request as an acceptable framework, SED shall be responsible for issuing annual data requests consistent with the process outlined at the end of the following discussion.

5.6. Discussion

In this decision we primarily address a process to “institutionalize” the annual reporting process consistent with SB 1371 by providing a timeline for Joint Staff deliverables, Respondents’ responses, etc. However, we also address major issues that parties have raised including concerns about transparency of data, larger utility versus ISP annual reporting, 2015 baseline and EFs, and data retention.

5.6.1. Confidentiality and Transparency of Data

California's Public Records Act (PRA), Gov. Code Secs. 6250 to 6276.48, generally requires public disclosure of government records upon request unless a specific exemption applies.²⁰ The Act specifically mandates disclosure of "air pollution emission data,"²¹ even if the data would otherwise be exempt from disclosure as trade secrets²² or under a variety of other exemptions.²³

²⁰ See Gov. Code Sec. 6253.

²¹ The requirement to disclose "air pollution emission data" expressly excludes "data used to calculate emission data," Gov. Code Sec. 6254.7(e), and these terms are not defined in

Footnote continued on next page

California statutes and case law reflect this presumption of disclosure. SB 1371 requires emissions quantification, in order to give the public “accurate information about the number and severity of leaks and about the quantity of natural gas that is emitted into the atmosphere over time.”²⁴

CPUC's most recent confidentiality decision was initiated to "increase public access to records furnished to the Commission by the entities we regulate, while ensuring that information truly deserving of confidential status retains that

statute. Their definitions in ARB regulation and Air District rules are not dispositive but may be helpful. ARB's toxic air pollution regulation defines "necessary data to calculate emissions" as including "annual process rate, maximum hourly process rate, controlled and uncontrolled emission factors, method of estimation code, process description field, . . . equipment size, maximum design rate, percent sulfur content, and emission factor origin code." See Cal. Code Regs., tit. 17, sec. 93300.5, incorporating Emission Inventory Criteria and Guidelines for the Air Toxics "Hot Spots" Program, Sept. 26, 2007. See also *Masonite Corp. v. County of Mendocino Air Quality Management Dist.* (1996) 42 Cal.App.4th 436 [49 Cal.Rptr.2d 639] (finding emission factors to be data used to calculate emission data, and therefore trade secret, under the prior codification of the definitions at Cal. Code Regs., tit. 17, sec. 93321(b)).

Multiple Air Districts' rules define "emission data" as "Measured or calculated concentrations or weights of air contaminants emitted into the ambient air." See, e.g., San Joaquin Valley Unified Air Pollution Control District, Guidelines for Implementing the California Public Records Act, Sept. 17, 2007, https://www.valleyair.org/General_info/pubdocs/PRRGuidelines09-17-07.pdf.

²² Gov. Code Sec. 6254.7(e).

²³ Gov. Code Sec. 6254 ("Except as provided in Sections 6254.7 and 6254.13, nothing in this chapter shall be construed to require disclosure of records that are any of the following:" (emphasis added)). For example, the Act's protection for "Geological and geophysical data, plant production data, and similar information relating to utility systems development, or market or crop reports, that are obtained in confidence from any person" do not apply to air pollution emission data. See Gov. Code 6254(e), 6254.7(e).

²⁴ Pub. Util. Code Sec. 975(e)(5). SB 1371 also prescribes, "Collected leak data shall remain the property of the utility and shall be available to the commission and parties in commission proceedings as determined by the commission or specified by statute." Data that remain property of the utility are not exempt from public records requirements, as the PRA defines "public records" to include "any writing containing information relating to the conduct of the public's business prepared, owned, used, or retained by any state or local agency regardless of physical form or characteristics." Gov. Code Sec. 6252(e)).

protection.”²⁵ The decision provides that, in a formal proceeding, the party seeking confidential treatment of data must follow specific procedures unless the Commission establishes a different process for the proceeding. These procedures, which include identifying the specific data claimed as confidential, justifying the basis for confidential treatment, and providing a signed declaration, are designed to shift the burden of identifying and substantiating data confidentiality from CPUC onto regulated entities seeking data protection.²⁶

In keeping with these statutory and regulatory principles, we support requiring Respondents to continue to post public versions of their annual reports online, including all data and templates that are not confidential.

In their comments, utilities have expressed reasonable concern that data specifying the locations of leaks (GIS coordinates and street addresses) remain confidential to ensure the security of critical infrastructure. (Joint Utilities’ October 30, 2015 Comments at 7.) We agree that precise location data should remain confidential for this reason. We agree with multiple parties that zip code or census tract is an appropriate level of aggregation for public leak data. (EDF and Utility Workers Union of America October 30, 2015 Comments at 11.)

SoCalGas and SDG&E also express confidentiality or liability concerns with publicly identifying dig-in repeat offenders. (SoCalGas/SDG&E February 20, 2017 Comments at 7.) Apart from protecting personal information (such as the names of individual employees who may be involved in a dig-in violation) there is no basis for withholding the names of offenders from the

²⁵ Decision (D.) 16-08-024, Aug. 25, 2016, quoting Order Instituting Rulemaking (R.14-11-011) at 1.

²⁶ D.16-08-024, Aug. 25, 2016.

public. Subject to these disclosure limitations on personal information, the CPUC will share repeat offenders' identities with local and state agencies, and make them publicly available.²⁷

We also recognize Joint Utilities' security concern regarding maximum allowable operating pressure (MAOP) and pipe diameter, but note that other utilities make this information public. (Joint Utilities' October 30, 2015 Comments at 7.) We will therefore direct that utilities shall include MAOP and pipe diameter in the reports publicly posted on their websites.

The utilities have argued that making the precise location of underground gas infrastructure leaks known in this proceeding could create a potential safety risk without a corresponding public benefit. In other proceedings, we have not viewed GIS locational data as presenting a heightened security risk for utility infrastructure. However, in this proceeding GIS level data is not required for the CPUC to fulfill statutory requirements, as more general census tract or zip code locational information is sufficient. Although it is unclear the precise degree of risk that would come from releasing the GIS locational data, the lack of a

²⁷ See Gov. Code Sec. 6254.20 ("Nothing in this chapter shall be construed to require the disclosure of records that relate to electronically collected personal information, as defined by Section 11015.5, received, collected, or compiled by a state agency."). Gov. Code Sec. 11015.5(d) defines "electronically collected personal information" as "any information that is maintained by an agency that identifies or describes an individual user, including, but not limited to, his or her name [and] home address," but this definition excludes "information on or relating to individuals who are users serving in a business capacity, including, but not limited to, business owners, officers, or principals of that business." Civ. Code Sec. 1798.24 generally prohibits agencies from disclosing personal information. Taken together, these provisions suggest that CPUC may not disclose names and addresses of individual repeat offenders (*e.g.*, an irresponsible homeowner), but may disclose information about repeat offenders operating in a business context (likely including independent contractors for hire).

corresponding benefit weighs in favor of protecting this information at this time.

The templates submitted by Respondents to the CPUC and ARB pursuant to the annual data request shall be considered non-confidential and shall be posted on Respondents' websites, except that GIS level locational data and customer level data may be redacted from templates, worksheets, appendices and any documentation posted on party's websites accessible to the general public. Aggregated locational data at the zip code level will be included in the publically available documents. No discrete customer level data or data that can be used to identify specific customers shall be shared or generally made available to the public by the CPUC, ARB or the parties absent a Commission order determining such release to be in the public interest.

Any discrete locational data may be shared with parties to the proceeding as long as they sign a non-disclosure agreement with the originating source, such that the discrete locational data (e.g., GIS, customer address, etc.) shall not be made available to the public and shall be considered a priori confidential information.

5.6.2. Larger Utility versus ISP Reporting

Throughout the proceeding, the ISPs make a compelling case that ISPs vary in size, type of infrastructure assets, and deployment of emissions monitoring technologies, and the challenges they face. This weighs against a one-size fits-all approach to reducing natural gas leaks or emissions. According to Lodi Gas Storage, "ISPs are limited in scope and purpose, and much more modern" so "... their 'footprints' – both physical and carbon are at the far ends of the respective physical size and emissions-impact spectrum." (Lodi Gas Storage, LLC, and Central Valley Gas Storage Joint PHC Conference Post-PHC

June 26, 2017 Comments at 2.) Utility and ISP facilities “were constructed and operated under a different business model – competitive market contracting for service at market rates versus cost-of-service rates.” (*Ibid.* at 2.) While California ISPs are within the jurisdiction of the CPUC, they differ substantially from what most think of when they refer to natural gas utilities:

- ISPs operate only limited pipelines assets.
- ISPs [generally] operate modern pipeline and storage assets.
- ISPs emissions are presently very low.
- ISPs’ rates (and in turn revenues) are the product of negotiation with customers (*ibid.* at 2).

As the ISPs have also pointed out, different reports should not be necessary based on company size. But the content of the submitted reports and interpretation of data submitted could vary. Because of the differences in size and nature of operations, comparing system-wide leak rates of large integrated transmission companies may not lead to meaningful analysis. If throughput is used in determining a company’s leak rate, smaller independent storage providers with lower throughputs may be placed at an inherent disadvantage that would be difficult to overcome with emissions reduction strategies.

However, while this decision acknowledges that ultimately different levels of requirements (and associated costs and administrative burdens) can be applied to the limited operations of ISPs, especially given ISPs relatively low emission levels, any burden of proof for requested exemptions should not be “automatic” and the burden of proof for the exemption shall rest with the ISP. ARB/CPUC will make a determination based on the evidence and records provided. Section 10 regarding “Compliance” discusses in more depth appropriate exemptions for ISPs.

5.6.3. Emission Factors and 2015 Baseline

ARB is considering revisions to several emission factors and will need to consider how those changes would be reflected in the 2015 baseline as well as the annual Joint Report. The emission factors are for two sectors: (1) distribution mains and services; and (2) M&R stations. ARB is considering these revisions due to recent studies including one specific to California.

On February 2, 2017 ARB held a working group session with respondents in this proceeding to review an analysis of updated EFs. The 2015 annual gas leaks and emissions reports filed with the CPUC and ARB primarily used the 1996 US EPA and Gas Research Institute (GRI) EFs. ARB reviewed and summarized options for updating EFs based on two recent studies of EFs for the two large source categories mentioned above. EDF, with support from industry, funded a study by Washington State University (WSU, 2015) to conduct leak measurements from distribution pipelines and M&R stations from several states, including California. ARB funded a study with the GTI to conduct measurements from unprotected steel and plastic natural gas distribution pipelines in California (GTI, 2016).²⁸

At this ARB-sponsored meeting, the three main utilities proposed to combine the California specific pipeline leak data from the 2015 WSU study with those from the 2016 GTI while EDF preferred not to do so. ARB has not made a final recommendation. Therefore, the reporting for 2017 will continue to use EFs from the 1996 US EPA and GRI study. Additional changes to EFs may occur in the future as new information is gathered and as the Best Practices are

²⁸ The study was completed in 2015 with a report submitted in 2016.

implemented. If the change is due to implementation of new technologies or new Best Practices, the baseline would likely not change.

Use of EFs is 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. EFs are able to supply averages with enough data points but cannot as easily account for super emitters. Because it is difficult to quantify the actual volume of leaks and emissions, more work is needed to develop and improve California specific EFs, including super emitters, until actual emissions measurements are available for the sources where it is feasible to directly measure emissions. The overall goal should be to use as much actual leak and emission data to provide as close to actual emissions estimates as possible.

Unfortunately, there are currently no cost effective means for direct measurement of leaks on a scale that would be needed to accurately measure all the natural gas emissions from pipeline systems in California. The best reporting methods now in use rely heavily on engineering estimates and the ARB approved EFs for estimating California natural gas emissions. Until such time, when either new EFs are developed and approved or better cost-effective tools for estimating actual emissions are deployed, there will continue to be reliance on EFs for estimating natural gas emissions from pipeline delivery systems.

Until new EFs are adopted in final form, operators should continue to use EFs as directed by CPUC and ARB in the annual reporting templates. ARB is funding a study to update EFs for MSAs.²⁹

5.6.4. 2015 Baseline of Emissions Reductions

The 2015 baseline emissions estimate provides a starting point to measure future natural gas emission reductions. Current legislation requires 2013 (and thereby also 2014) data. However, the May 15, 2015 reports contained gas emission volumes based on a wide variety of EFs that were not consistent and which did not provide an “apples to apples” comparison among the gas corporations. The 2015 baseline emissions estimate, which utilities do not generally object to, could change with the modification of EFs to better estimate emissions and leaks. Retroactive application of the EFs could result in a significant revision to the 2015 baseline emissions estimate.

As stated above, the development of EFs and an official baseline to manage this initiative in the long term is still in flux. Therefore, while, ARB is ultimately responsible for the development of EFs in collaboration with stakeholders, both ARB and CPUC should continue to collaborate to ensure that updates to EFs are completed in a timely fashion consistent with the Commission’s annual reporting process. Following this year’s example, if changes are required to the annual reporting template, ARB and CPUC staff will conduct a workshop to discuss EFs and ongoing changes to the reporting template. This workshop should take place during the first quarter of each year before SED issues the annual data request at the end of the first quarter.

²⁹ ARB/GTI Agreement #15ISD023, *Quantifying Methane Emissions from Natural Gas Residential Customer Meters in California*.

5.6.5. Data Retention

EDF suggests that streamlining regular analysis through a comprehensive leak database would benefit Joint Staff who, at present require half a year to review a single set of reports. (EDF December 22, 2016 Comments at 5.) A database system may allow regulatory agencies to take a “snapshot” of the leaks on the system which includes thousands of lines of data and explanations, etc.³⁰ Establishing, funding, maintaining, and managing a shared common database across all utilities might allow regulatory agencies to check statistics in “real time” and determine if utilities are out of compliance or not repairing leaks on a required schedule.³¹ EDF argues that most, if not all utilities, track leaks and the associated information electronically, so this data should be available anyway.

While this proposal sounds attractive, establishing a common database is not practical at the present time and would detract from more important priorities such as the development of a robust set of annual reporting metrics and Best Practices. Sufficient measures are in place to adequately track methane emissions and support emissions reduction efforts. It makes sense to reconsider this shared comprehensive methane leak database proposal in Phase Two, after a baseline year and more consistent EFs are established for different categories of emissions, and the details of various compliance plans, and interim emission targets, will be determined. In the short-term, utilities’ compliance plans should detail how they expect to retain data for purposes of accomplishing their own trend analysis and leak repair schedules over time.

³⁰ This potential action assumes that utilities are updating their databases in real time which may not be practical or feasible at this stage in the proceeding.

³¹ Regulatory agencies do not currently perform real time audits of leak repair performance.

5.6.6. Ongoing Annual Reporting and Timelines

ARB and CPUC, in cooperation with key stakeholders, have made significant strides toward fulfilling and indeed exceeding the minimum annual reporting requirements as specified in SB 1371. Since the January 1, 2015 effective date of SB 1371, Joint Staff have published three annual data requests, which resulted in two annual reports illustrating trends; a third annual report is pending. According to parties, utility responses and annual reports have accurately documented trends and reduction of emissions consistent with SB 1371 goals. Continued collaborative efforts of all stakeholders will improve reporting over time to facilitate future comparisons and trend analysis in fulfillment of SB 1371 goals.

5.6.7. Annual Report Process

The Commission's SED, in consultation with ARB, shall manage the annual report process as follows:

- Prior to the issuance of the annual data requests, SED Staff shall host a workshop to discuss the updated format and to ensure consistency with data which are separately reported to ARB and PHMSA. If there are no changes to the format and no new data, the workshop may be deemed unnecessary and cancelled with notice.
- SED shall submit annual data requests to Respondents consistent with Public Utilities Code Section 975(c) and SED advice by March 31 that covers the previous calendar year.
- Respondents shall submit to SED and ARB Staff (Joint Staff) a response to the data request with excel populated spreadsheet templates via DVD by June 15 of each year.
- Respondents shall submit responses through the "Supporting Documents" Feature on the Commission's Electronic Filing System by June 15 of each year.

- Respondents shall submit responses consistent with the Commission's confidentiality rules and guidelines according to this decision.
- Respondents shall post public versions of these reports on Respondents' individual website and shall include all templates and all data points that are not confidential pursuant this decision.
- Joint Staff shall post a draft annual Joint Staff Report on the Commission's website by November 15 and the ALJ shall solicit parties' comments.
- Based on comments, Joint Staff shall post a final draft report highlighting corrections/enhancements by December 31 or as soon as practicable.

SED, in cooperation with ARB, shall be responsible for enforcing the Annual Reporting framework and providing ongoing enhancements to the Annual Spreadsheet Template.

6. Cost Effectiveness, Technological Feasibility, and other Considerations

6.1. SB 1371 Requirements

According to SB 1371, as reflected in § 975 (e), the rules and procedures adopted ... shall accomplish all of the following:

- (1) Provide for the maximum technologically feasible and cost-effective avoidance, reduction, and repair of leaks and leaking components.
- (2) Provide for the repair of leaks as soon as reasonably possible after discovery, consistent with established safety requirements...and the climate change impacts of methane emissions.
- (4) Establish and require the use of best practices for leak surveys, patrols, leak survey technology, leak prevention and leak reduction.

According to § 977 (d) the Commission shall consider “the impact on affordability of gas service for vulnerable customers as a result of incremental costs of compliance with the adopted rules or procedures.”

It should be noted that since this proceeding opened in January 2015, the California State Legislature approved Assembly Bill (AB) 197 (Garcia, Ch. 250, Statutes of 2016) on Sept. 8, 2016, which updates Health and Safety Code Sec. 38562.5 and directs that “the state board shall ... consider the social costs of the emissions of greenhouse gases.”³²

6.2. Parties’ Comments

EDF and CUE believe that the aim of SB 1371 is to reduce methane emissions and that cost and cost-effectiveness is secondary under the statute. According to EDF, “It is premature to make a determination now as to what is cost effective, when the other criteria in the balancing equation are unknown.” (EDF November 20, 2015 comments at 4.) EDF also believes that including the social cost of methane (SCM) in the evaluation gives the Commission security that the costs of its requirements are evaluated against the actual costs to society from the air pollutant, and is consistent with the goals of AB 197. (EDF December 22, 2016 Comments at 3-4.) In this context, EDF believes that costs for the program should be considered as a whole with broad consideration of cumulative impacts, including social costs.

³² The US EPA Definition of “Social Cost”: From a regulatory standpoint, social cost represents the total burden a regulation will impose on the economy. It can be defined as the sum of all opportunity costs incurred as a result of the regulation. These opportunity costs consist of the value to society of all the goods and services that will not be produced and consumed if firms comply with the regulation and reallocate resources away from production activities and towards pollution abatement.” (ARB November 3, 2016 Workshop Report at 7.)

In general, Utilities, TURN, and ORA support a cost effectiveness proposal in which costs are contained to the greatest extent possible by focusing on each utility's methane reduction measures that provide the "biggest bang for the buck" for that utility. PG&E recommends implementation of cost effectiveness methodology that is based on three broad analytic steps:

- 1) a ranking of planned emissions reduction work by cost per unit of reduction;
- 2) an evaluation of proposed emissions reduction work within each rate case; and
- 3) a detailed description of the operator's proposed compliance plan based on steps one and two. (PG&E December 22, 2016 Comments at 3.)

PG&E further opines, "[a]s more information is developed by ARB on SCM as part of implementing AB 197 and SB 32, "it may be appropriate for operators to include SCM considerations in their annual SB 1371 compliance plans." (*Ibid.* at 3.) PG&E warns, "Attempting to quantify societal benefits or employ a cost-benefit methodology would potentially delay completion of Phase 1 and SB 1371 methane emissions reductions measures." (PG&E December 9, 2016 Comments at 4.)

SoCalGas/SDG&E support developing cost-effectiveness in terms of dollars per metric ton or thousand standard cubic feet of methane reduced. (SoCalGas/SDG&E December 9, 2016 Comments). They are not opposed to considering social costs, but do not have the internal experts to properly conduct such an assessment. (SoCalGas/SDG&E December 9, 2016 Comments at 5.)

In an effort to develop a common methodology that provides a relative ranking of best practices, the four major utilities offered a proposal at the October

2016 workshop, that is compatible with ongoing work in rate cases. This proposal is set forth in the table below:

Proposed Utility Cost Effectiveness Methodology

CAPITAL COSTS	<ul style="list-style-type: none"> • Determine Net Present Value of Best Practices Capital Costs; • May include cost of engines, portable compressors, vapor recovery systems, piping thermal oxidizers, over life of equipment
O & M COSTS	<ul style="list-style-type: none"> • Determine Net Present Value of Equipment and Labor, etc. • May include staff, supervision, clerical, monitoring, testing, lab work, analysis, recordkeeping systems, training, surveys, report preparation, etc.
GAS SAVINGS	<ul style="list-style-type: none"> • Estimate volume of Gas Reduced (MCF methane) and cost; • Note that Gas Flared/combusted cannot be monetized; • Recovered gas volumes can be monetized to reduce overall best practices costs
\$/MCF GAS	<ul style="list-style-type: none"> • Divide combined capital and O & M Costs by volume of gas reduced to get \$/MCF value; adjust for monetized gas savings if applicable.

According to utilities, this approach will enable operators to target “low hanging fruit” for emissions reductions. In any compliance plan, there must be provisions to show progress for super emitters so that operators are not only selecting cost-effective measures to implement, but working to reduce and/or identify super emitters sooner. Pilot studies could be used to verify costs and performance for future adoption may be included. Utilities agree that the Commission should prioritize spending that leads to measurable emissions reductions. (Joint November 20, 2015 Comments at 6.)

Similarly, TURN recommends that the Commission require the utilities to produce a ranking of the best practices based on cost per unit of emissions reduction. (TURN December 9, 2016 Comments at 6.) However, TURN is

concerned that the costs of new technologies and measures are somewhat uncertain. For example, TURN notes that the cost of “rerouting blowdown gas” is uncertain and the high cost of “more frequent inspections” and the value proposition may be unclear. (TURN October 2016 Workshop Comments at 5-6.) In the face of cost uncertainty, TURN believes that respondents should only implement best practices that clearly provide value and thus meet a cost effectiveness standard. It agrees with utilities that pilots should be authorized for certain emerging technologies if data is lacking. Once better cost information and methane reduction impact data for best practices are obtained, incremental adjustments can be made. (*Ibid.* at 6.) Both ORA and TURN believe that best practices whose costs are uncertain should not be implemented until costs can be established. (TURN presentation November 3, 2016 on slide 6; ORA December 9, 2016 Comments at 3.)

In general, ISPs believe that best practices should be focused on achieving the largest reductions with the least cost. They want to avoid additional costs for those who have already invested in modern equipment and have achieved very low emissions. ISPs state that they do not currently have any means of recovering from their customer expenditures that exceed purely economic benefits. Central Valley Gas Storage advocates a “safe-harbor threshold established, below which further expenditures to attain additional emission reduction are not required.” (Central Valley Gas Storage November 20, 2015 Comments at 2-3.) Lodi Gas Storage believes that “smaller utilities with modern technology and already low leak rates should not have to incur the same cost as larger utilities that can achieve greater emissions simply because, as a by-product of age, older technologies, etc., they start with a much greater level of emissions.” (Lodi Gas Storage November 20, 2015 Comments at 7.)

CUE argues that “neither section 961 nor section 975(b) declare ‘cost effectiveness’ to be a threshold for a safety related practice (Pub. Util. Code § 961(d)) or a leak reduction practice (Pub. Util. Code § 975(b)).” (CUE November 20, 2015 Comments at 6.) Similarly, CUE believes that the SB 1371 issue of cost with respect to prompt repair of leaks and best practices is relevant only to ensure that the Commission ‘consider’ but not mandate the impact on affordability of gas service for vulnerable customers. (CUE December 22, 2016 Comments at 3.)

CUE also believes that a cost effectiveness methodology should be the same for all utilities. “Variations among utilities should be based on granular consideration of costs, which vary among utilities, and the incremental benefit – leak reduction and resulting hazard emission reduction – which also varies among utilities, given their respective starting points as revealed by their Reports.” (CUE November 20, 2015 Comments at 16.)

6.3. Discussion

6.3.1. Statutory Context

We agree with EDF and CUE that the main aim of SB 1371 is to reduce methane emissions from natural gas pipeline facilities, and conclude that in determining rules, regulations and transportation rates for pipelines we must consider the global warming impact of methane emissions alongside our duty to ensure safety, reliability, and just and reasonable rates. However, cost and cost-effectiveness also are important considerations, because it would not be in the public interest for the Commission to require actions of gas utilities that result in unjust or unreasonable rates.

The statutory text created by SB 1371 requires the CPUC to commence a proceeding to “adopt rules and procedures governing the operation,

maintenance, repair, and replacement” of intrastate transmission lines to “reduce emissions of natural gas ... to the maximum extent feasible in order to advance the state’s [GHG emissions reduction] goals” (§ 975 (b).) In doing so, “safety, reliability, and affordability of service” should be given priority, and cost are to be given “due consideration.” (§ 975(b) and §975(b)(2)).³³ However, particularly in light of cost data uncertainty, we also agree with TURN that costs and ratepayer affordability are important considerations to keep in mind when developing best practices.

6.3.2. Central Debate

We concur with PG&E that the central debate, based on the November 3, 2016 cost-effectiveness workshop, appears to be whether in implementing SB 1371, the Commission should adopt a cost-effectiveness methodology for operators to evaluate and prioritize best practices, as proposed by the Utilities and TURN, or develop a broader cost-benefit methodology as suggested by EDF and ARB. (PG&E December 9, 2016 Comments at 2.) Multiple parties recommend the adoption of a cost-effectiveness test, threshold, or ranking through which only Best Practices determined individually to be cost-effective, or most cost-effective, would be required or implemented. However, we agree with CUE that “SB 1371 does not require nor authorize a threshold cost determination of cost effectiveness.” (CUE May 20, 2016 Comments at 5.) But as a matter of Commission policy, we are concerned about the just and

³³ This provision references the “cost considerations of § 977 which has four provisions; it is not clear whether all four are considered to be “cost considerations.”

reasonableness of rates; therefore, unfettered or unmanaged spending to cover leak reduction initiatives, is not a viable option.³⁴

6.3.3. Cost Benefit Test

We appreciate PG&E's concern that "[a]ttempting to quantify societal benefits or employ a [comprehensive] cost-benefit methodology in this proceeding would potentially delay completion of Phase I and implementation of methane emissions reduction measures." (PG&E December 9, 2016 Comments at 4.) We do not advocate further analysis at this time. However, we generally do not view cost-benefit analysis as more time-consuming than the cost-effectiveness determination that some parties have suggested.

6.3.4. Cost Effectiveness Methodology

There is merit to EDF's argument that rather than providing cost-benefit ratios for each of the measures for the purpose of establishing cost-effectiveness thresholds or ranking of each proposed practice, as the utilities have proposed, the Commission should consider cost for the program as a whole – taking into account the overlapping nature of benefits of each best practice. (EDF December 9, 2016 Comments at 10.) In the long-term, it would be laudable to consider broad cumulative impacts, including social impacts, as part of a holistic evaluation of benefits and costs of the 26 Best Practices as a whole and in context. However, given the current lack of cost data that pertain to individual best practice pilots and R&D initiatives (and various initiatives that may provide comparable performance to existing Best Practices), there is no convincing evidence that consideration of total program costs is possible to achieve in the

³⁴ See § 451.

short-term. This is especially true when one considers that Respondents must file compliance plans as part of their Safety Plans in Spring 2018.

We also acknowledge that given the numerous unknowns associated with this new program, there is not enough quantifiable information to evaluate the cost-effectiveness of the identified and required Best Practices at this time. We do not believe it is appropriate to adopt a numeric determination of cost-effectiveness as a “threshold” value.

However, cost-effectiveness is an important factor to consider in the analysis of the Best Practices as implemented (including pilot projects and other specified flexibility measures) to determine whether refinements to the Best Practices are needed. As ORA notes, future consideration of cost-effectiveness with respect to implemented Best Practices “will allow for review of the Best Practice implementation efficacy and costs” and “also allow individual Best Practices to be compared between utilities to better assess if any changes can be made to improve their efficacy.” (ORA December 22, 2016 Comments at 4.) We note that any adjustment to a Best Practice should only occur once sufficient data on the costs and emissions reductions for the Best Practice is collected across each utility.

With the implementation of the program and the required reporting to be submitted in 2020, Commission Staff will have sufficient additional information to evaluate the cost-effectiveness of each individual compliance plan and best practices. The vast majority of ungraded emissions (64%) 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 (while meeting their requirements under all the Best Practices). By using actual emissions data,

utilities should be able to address operating and maintenance practices, and component designs and materials to facilitate emission reductions.

In the meantime, we are sympathetic to views of utilities, ORA, and TURN about implementing the “biggest bang for the buck” strategies in the 26 mandatory Best Practices. Such an approach would systematically balance tradeoffs between emissions reductions, safety, and affordability of gas service for a particular utility given their unique business model, operating conditions, and physical configuration of the gas system.

While we agree with ORA and TURN that when costs are uncertain, additional consideration should be taken into account; but we do not agree that this means the Best Practices should not be compulsorily implemented. (TURN November 3, 2016 Workshop Presentation, ORA December 9, 2017 Comments.) As EDF notes, the significant flexibility added to many of the Best Practices address cost concerns. (December 22, 2016 Comments at 6.) The flexibility includes exemptions, consideration of an alternative compliance pathway where a Best Practice is infeasible for the utility in the particular compliance cycle, and pilots or R&D initiatives. The pilots and R&D initiatives will require the submission of cost and emission reduction information and thus can be reevaluated in the future.

That being said, we believe that costs for most of the Best Practices especially for those that relate to “Policies and Procedures,” “Record Keeping,” “Training,” “Experienced/Trained Personnel,” etc., are manageable. These Best Practices are already being implemented, and do not necessarily involve large capital or incremental expenditures. Thus, they can be implemented immediately with proper cost controls and justification through existing rate cases.

We agree with EDF that “including the [social cost of methane] is important to the overall understanding of the avoided costs associated with emissions reduction practices, and should not be ignored.” (*Ibid.* at 12.) However, although our partner ARB supports specific valuation (as completed by the Interagency Working Group (IWG) and supported by U.S. EPA³⁵), ARB views it as a consideration and not a threshold at which to take action. As such, ARB does not view valuation as necessary to move forward with Best Practices today.

We agree with the ISPs that reporting data and analysis show that ISPs’ methane emissions are on a different scale than utilities’ emissions (ISPs February 10, 2017 Comments at 3.)³⁶ Because of this, the Best Practices provide ISPs with exemptions from certain Best Practices and other flexibility measures as appropriate. The ISPs have also requested that we establish a threshold for ISPs, “either an absolute emissions number or a percentage of system throughput,” “below which further expenditures to attain additional emission reduction are not required.” (ISPs Dec. 9, 2016 Comments at 3.) In the nascent stages of a methane gas leak abatement program, we do not think it is necessary to establish such a threshold. However, we may visit this in future cycles of the program as more emissions and cost data become available.

³⁵ See

https://obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/august_2016_sc_ch4_sc_n2o_addendum_final_8_26_16.pdf.

³⁶ According to ISPs, “compared with the data that the ISPs reported to the CPUC in 2016, the ISPs, in total emit less than ½ of one percent of all reported gas utility methane contributions.”

6.3.5. Emerging Technologies and Cost Flexibility

Some degree of flexibility is needed to revise Best Practice requirements as technologies rapidly change and more feasible methods for detection and repair are identified and become available at scale. We do not think that we need to wait until all of the technologies are mature or are established before we implement relevant requirements. However, we agree that there is more than one potential state-of-the-art technology that may work in more than one service territory given its unique geography and/or facilities configurations. (SoCalGas, Southwest Gas, SDG&E December 4, 2015 Comments at 4.)

In this context, the definition of “maximum technologically feasible” technologies includes not only commercially available technologies, but also R&D where appropriate. We agree with EDF and CUE that this definition of maximum technologically feasible must include only those technologies that achieve the largest reductions in emissions. (EDF and CUE December 4, 2015 Comments at 11.)

6.3.6. Setting Rates for Pilots and Cost Containment

For purposes of setting the rates to be charged by respondents for the services or commodities furnished by it, the Commission may allow the inclusion of expenses for research and development. (§ 740)

According to § 740.1., the commission shall consider the following guidelines in evaluating the research, development, and demonstration programs proposed by utilities:

- (a) Projects should offer a reasonable probability of providing benefits to ratepayers.
- (b) Expenditures on projects which have a low probability for success should be minimized.

- (c) Projects should be consistent with the corporation's resource plan.
- (d) Projects should not unnecessarily duplicate research currently, previously, or imminently undertaken by other electrical or gas corporations or research organizations.
- (e) Each project should also support one or more of the following objectives:
 - (1) Environmental improvement.
 - (2) Public and employee safety.
 - (3) Conservation by efficient resource use or by reducing or shifting system load.
 - (4) Development of new resources and processes, particularly renewable resources and processes which further supply technologies.
 - (5) Improve operating efficiency and reliability or otherwise reduce operating costs.

Issues related to other criteria such as "technological feasibility," and "use of best practices" will be addressed in Section 7 "Best Practices"; Section 10 "Compliance and Evaluation"; and Section 11 "Cost Tracking and Cost Recovery."

7. Best Practices (General)

7.1. SB 1371 Requirements

As referred to above, the second requirement of this rulemaking is to solicit input from utilities and other interested persons on what rules and procedures should be adopted by this Commission. As set forth in § 975 (e), rules and procedures should, among other things, be technologically feasible, cost effective, and use best practices.

Section 975 (e)(4) compels the Commission to:

Establish and require the use of Best Practices for leak surveys, patrols, leak survey technology, leak prevention, and leak reduction. The commission shall consider in the development of Best Practices the quality of materials and equipment.

Two related questions in the July 24, 2015 Scoping Memo in this rulemaking are:

- Should the Commission require specific methods and technologies to detect and measure leaks? What Best Practices should be required?
- How should preventive maintenance and operations and other efforts be employed to prevent leaks and other emissions, including third-party dig-ins?³⁷

The Scoping Memo also encouraged the use of a Working Group and workshops to accomplish scoping memo objectives.³⁸

7.2. Background

In compliance with the direction of the Scoping Memo, SED and ARB hosted a workshop on October 27, 2015 to discuss Best Practices cost effectiveness, and parties' related presentations:³⁹ Professor Joseph C. von Fischer of Colorado State University gave a presentation on leak quantification using mobile sensors and PG&E, Southwest Gas, Sempra, and EDF gave presentations on Best Practices.

³⁷ Scoping Memo at 7-8.

³⁸ Scoping Memo at 13.

³⁹ All parties to the proceeding were invited to participate in the workshop and make presentations. All presentations can be found on the CPUC Risk Assessment webpage at: <http://www.cpuc.ca.gov/riskassessment/>.

Subsequent to the workshop, SED and ARB Staff (Joint Staff) hosted meetings by telephone and in person, to further focus on the specific Best Practices preferred by the parties to identify and mitigate leaks and emissions.⁴⁰

December 8, 2015, teleconference:

Transmission Blowdowns and M&R Station Blowdowns.

December 22, 2015, teleconference:

Compressor Stations – Leaks from Valves, Connections, Meters, Vents, Packing, Blowdowns, etc.

January 5, 2016, teleconference:

Storage – Control Vents, Leaks, Blowdowns, Storage Compressors, Casings, other sources of Leaks and Emissions.

January 19, 2016, meeting at EDF offices at 123 Mission St., San Francisco:

Customer Meter and PHMSA “minor” releases (threaded connection leaks) AND Leak Surveys, Patrols, Leak Survey Technology, Leak Prevention, Leak Reduction, Leak Repair and Required Repair Times for Leaks.

“Know Your Risers” presentation by the Utility Workers Union of America, addressing the dangers of corroded anodeless risers, a steel casing with a plastic pipe inside that carries the gas to the stop valve and meter assembly.

January 20, 2016, continuation meeting at the EDF offices:

Selection of Best Practices for the Working Group Proposal.

Cost Effectiveness – Discussion by Southern California Gas regarding the cost effectiveness methodology presented in the ICF Report titled, “Economic Analysis of Methane Emission

⁴⁰ The parties who participated were Sempra Utilities, PG&E, Southwest Gas, Central Valley Gas Storage, Lodi Gas Storage, Wild Goose Gas Storage, EDF, the Utility Workers Union of America, CUE, TURN, ARB, and ORA.

Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries”, dated March 2014.

“Best Practices/Effective Results - Safe Harbor Proposal” presentation by the Independent Gas Storage Providers (ISPs).

These working group meetings led to the creation of a consolidated spreadsheet, listing over 100 potential Best Practices for policies, practices and technologies that specifically relate to the system components and operational areas mentioned above. The spreadsheet briefly describes the proposed Best Practices, which parties proposed them, lists pros and cons, and – where information was readily available – estimated emissions that may be avoided through the use of the best practice and the potential costs of the measures. Additional comments about the proposed items that came up during the working group meetings were included, as well as a link to the U.S. Environmental Protection Agency Natural Gas STAR site in cases where the item has already been identified as a Best Practice by the U.S. EPA.

Best Practices were further identified by functional categories: Operational, Monitoring, Process/Program Development and Training, Existing/Standard Practices, Research & Development, Crossover (may apply to several categories) and Maintenance. The comprehensive spreadsheet is available on the SED Risk Assessment web site and provides the background research that preceded the development of the 26 Best Practices approved in this decision.⁴¹ The current list of 26 Best Practices covers topics in the areas of Policies and Procedures, Recordkeeping, Training, Leak Detection, Leak Repair, and Leak Prevention. The adopted set of 26 Best Practices in this decision have

⁴¹ Refer to the Risk Assessment website at: <http://www.cpuc.ca.gov/riskassessment/>.

been derived through collaboration among all participants. However, full consensus on the application of individual Best Practices was not reached.

7.3. Key Principles

To guide development of methane leak abatement Best Practices, Joint Staff, in cooperation with the Best Practices Working Group, developed four principles for Methane Leak Abatement Best Practices. The following principles incorporate parties' comments:

1. Best Practices go beyond technologies and tools to embody a new way of doing things. Policies, practices, and education are as important as new technologies, and may provide additional methane reduction opportunities at lower cost (For example, the "find it, fix it" policy for fixing leaks when found, in some cases, may be more cost effective than monitoring and returning later to fix the leak).
2. Industry standards for safety and supplemental measures are needed to meet the challenge of eliminating methane emissions to the extent necessary to meet state goals.
3. If we can use the most advanced, technologically feasible, cost-effective measures to further reduce methane emissions beyond established targets, we should.
4. Improved methane detection by itself isn't enough; it should be coupled with better quantification and accurate categorization, and matched with a plan/timetable for mitigation in manners that are cost-effective and effective in minimizing the release of methane.

7.4. Parties' Comments

General

In general, utilities, ISPs, TURN and ORA generally support the revised Best Practices, but EDF and CUE generally do not.

According to PG&E, "PG&E is generally supportive of the Best Practices, which will make meaningful methane emission reductions and provide

flexibility for operators to choose the best portfolio of measures.” (PG&E February 10, 2017 Comments at 3-4.) According to Southwest Gas, “Southwest Gas believes that SED’s Best Practices was well thought out and representative of the various interests of stakeholders.” (Southwest Gas February 10, 2017 Comments at 5.) Consumer advocates concur with utilities. “TURN finds that the revised Best Practices (BPs) are generally reasonable.” (TURN February 10, 2017 Comments at 1.) ORA notes that the last round of workshops in December 2016 promoted a collaborative process and constructive input from stakeholders. (ORA February 10, 2017 Comments at 2.) It observes that “many of the Best Practices have been improved by permitting the deployment of pilots and research and development projects, where the feasibility of a full-scale program is uncertain.” (*Ibid.* at 2-3.) “This will allow each utility to study different methods of complying with best practices and allow determinations regarding which method is optimal in cost-effectively reducing emissions in its system” (*Ibid.* at 3.)

In contrast, CUE and EDF do not support the latest Staff Proposal since it was “reworked” following the publication of its March 2016 version. According to CUE, “The best practices proposed by Staff neither conform to the letter of the law nor achieve its purpose.” (CUE February 10, 2016 Comments at 4.) It claims that the “utilities convinced Staff to water down regulations based on unsubstantiated claims that the proposed measures are infeasible or unaffordable.” (*Ibid.* at 4-5.)

EDF commends the agencies for their support and progress and acknowledges that the revised Best Practices were the product of multiple days of technical workgroup meetings, collaborative engagements and stakeholder comments. (EDF February 10, 2017 Comments at 7.) “At the same time, EDF is

concerned that, if adopted as proposed, the leak report analysis and best practices will not conform with the requirements of the law set forth in SB 1371. Specifically, if adopted, ARB and the Commission will not have fulfilled the transparency requirements, or the mandate to ‘establish and require the use of best practices’.” (EDF February 10, 2017 Comments at 1-2.) “EDF also argues that “the changes and additional recommendations made by the Commission staff that are designed to provide more ‘flexibility’ to utilities detract from necessary requirements, removing the decision making from the hands of the Commission and improperly replacing it with the regulated entities.” (*Ibid.* at 2.)

Flexibility with Implementing Best Practices

SoCalGas SDG&E, PG&E, Southwest Gas, ISPs & ORA support flexibility (e.g., exemptions, pilots, R&D) for some Best Practices but EDF and CUE oppose it. SoCalGas/SDG&E, PG&E, Southwest Gas & ISPs state flexibility for some Best Practices is critical. PG&E states that this flexibility “is both prudent as utilities with input from parties, will be permitted to determine and propose the set of least-cost, greatest-reduction measures and it is also very practical for operators to have this flexibility as many of the Best Practices will take significant work to operationalize and others need additional R&D or piloting before they can be scaled. (PG&E February 10, 2017 Comments at 6.) In short, it states, “Thus the recommendations balance the need for aggressive and achievable reductions with customer affordability, and operational and technical feasibility.” (*Ibid.* at 6.)

SoCalGas/SDG&E explain that evaluation of Best Practice implementation is critically needed before blanket implementation. (SoCalGas/SDG&E February 10, 2017 Comments at 2 and December 22, 2016 Comments at 7.) It provides the example of BP 22, Pipe Fitting Specifications in which “utilities need

to evaluate their respective systems to first assess where the need for such a Best Practice exists (if it exists) prior to proposing and implementing a plan of action to save time, effort, & expense.” (SoCalGas/SDG&E February 19, 2017 Comments at 5 and December 22, 2016 Comments at 7-8.)

According to the ISPs, they have no plans to propose R&D programs, but may wish to accomplish some with technology advances in advance of the timeframe in which ISPs have to submit a Compliance Plan. (ISPs December 10, 2016 Comments at 6.)

In contrast to the utilities’ and ORA’s views, CUE believes that all of the originally Best Practices (i.e., SED Staff March 2016 Initial Proposal) are “feasible” and “affordable” and consider the emphasis on exemptions, pilots, and R&D program, as “thinly veiled attempts to delay compliance with SB 1371, or make compliance little more than status quo.” (CUE February 19, 2017 Comments at 10.) In contrast to the original set of Best Practices, they summarize that this revised set of Best Practices would fail to sufficiently reduce methane emissions because:

- Outright exemptions were added to 21 of 26 best practices;
- An option to propose a research and development project instead of complying with the requirement was added to 7 of the 26 best practices; and
- The option to propose an alternative measure was added to 1 of the 26 best practices, although CUE interpreted Staff’s suggestion to be an exception applying to 4 of the best practices. (*Ibid.* at 10.)

EDF complains that “the conditions, qualifications and exemptions” provide the utilities with the ability to not implement Best Practices, and fail to include any “safeguards” to ensure the required methane emissions reductions. (EDF February 10, 2017 Comments at 15).

SoCalGas/SDG&E reply that “EDF and CUE seek to eliminate the flexibility of the Best Practices, ignoring differences among utilities.” (SoCalGas/SDG&E February 10, 2017 Comments at 1.) They emphasize that during the December technical workshops, the parties worked together to refine and clarify the mandatory Best Practices. EDF and CUE participated in these workshops and had the opportunity to make suggestions. At the meetings, parties developed a consensus that some flexibility in some of the Best Practices is necessary to allow for the uniqueness of each gas corporation’s system. “This flexibility would allow utilities to propose and justify substitute Best Practices or perform pilots or research and development if there was uncertainty around technology capability or effectiveness.” (*Ibid.* at 1.)

Overlapping Requirements with other Best Practices and other Regulations

SCG/SDG&E and ISPs request clarification to avoid conflicts between other pending (and final) regulations. For example, SCG/SDG&E argues that if the DOGGR (Department of Conservation's Division of Oil, Gas, and Geothermal Resources) gas storage rules or ARB Oil and Gas regulations, are complied with, and if that compliance falls within the same work practice areas as BPs 8 (Company Emergency Procedures), 18 (Stationary Methane Detectors), 19 (Above Ground Leak Surveys), 23 (Minimize Fugitive & Vented Methane Emissions), 24 (Dig-Ins/Public Education Program), and 25 (Dig-Ins/Company Standby Monitors), then those Best Practices should also be considered fulfilled. (SoCalGas/SDG&E February 10, 2017 Comments at 5.) It recommends that the words “should not be duplicative” should be changed to “this BP is met by meeting the final requirements of the ARB and DOGGR regulations.” (*Ibid.*)

Similarly, ORA argues “it is unclear what additional benefit BP 24, ‘Dig-Ins/Public Education Program’, as currently proposed will provide over current practices and an examination is needed to determine their efficacy in increasing safety and reducing emissions.” (ORA February 10, 2017 Comments at 3.) As was discussed at the December 2016 workshops, the utilities already implement public awareness programs to encourage excavators to call 811 (BP 24 Dig-Ins/Public Education Program). California state law requires excavators planning to conduct an excavation to contact the appropriate notification center two days in advance of excavation work. (See <https://www.digalert.org/calaw07.html>.) ORA is concerned that in some situations excavators may opt not to call 811 even if they have been informed of the necessity to do so through existing education programs. ORA states if anyone deliberately fails to notify the utilities of excavation work, then emphasizing an education program might not have a major impact on reducing natural gas emissions. (ORA also states Dig-Ins, Third Party or otherwise, are a significant safety concern. However, based on available data in this proceeding, they are not a significant source of methane emissions.) (*Ibid.* at 3.)

EDF suggests that SoCalGas/SDG&E’s argument “inappropriately limits CPUC’s authority to set stricter standards and regulations than ARB and DOGGR, and fails to take into account that different standards can cover similar work practice areas while yielding different and synergistic results.” (EDF February 10, 2017 Comments at 2.) For example, EDF observes that CPUC may require more frequent inspections than other agencies, and compliance with the CPUC regulations is stricter than what is necessary to comply with ARB or DOGGR regulations. In this case, compliance with ARB and DOGGR regulations would not mean compliance with more rigorous CPUC regulations. According

to EDF, “CPUC must retain its ability to set stronger standards than the other agencies because the Commission will be in the position to update requirements if the appropriate reductions are not made.” (*Ibid.* at 2.) Even if CPUC rules are less stringent now, the Commission must retain the authority to set a stronger standard in the future.

Cost Effectiveness of Best Practices

In its comments, CUE states that cost-effectiveness is not relevant and should not be a consideration when implementing best practices. (CUE February 10, 2017 Comments at 7.) TURN cites a previous Commission decision denying PG&E authorization for cost recovery by ratepayers for a three-year distribution leak survey cycle program due to unclear natural gas leak abatement benefits based on implementation costs. (TURN February 10, 2017 Comments at 3, citing D.14-08-032 at 74-80 for PG&E’s 2014 General Rate Case (GRC).) According to TURN, “the fundamental problem is that there is insufficient evidence at this time to evaluate 1) the nature of gas leaks on different distribution pipes; and 2) the combined impact of using different technologies and/or more frequent survey cycles on the identification of leaks.” (TURN February 10, 2017 Comments at 2.) TURN points out that some of the relevant data will be collected in the context of the pending Settlement in PG&E’s rate case. TURN recommends that the Commission order the collection of the necessary additional evidence and delay implementation of BP 15 until relevant data is gathered and analyzed. (*Ibid.* at 2.) More information is needed on “1) leak find rates by survey method; and 2) factors impeding the grading characteristics of a leak. (*Ibid.* at 3 citing PG&E Settlement filed in ongoing Test Year 2017 case: Sections 3.2.1.1.2 and 3.2.1.1.3.) PG&E has agreed to

accelerate leak surveys to a four-year cycle in its pending 2017 General Rate Case Settlement.

SoCalGas/SDG&E also argue that BP 15 should not be mandatory at this time as cost estimates to date for all Best Practices have only been rough estimates based on assumptions that may not be consistent with the final cost-effectiveness methodology that we want to adopt to satisfy SB 1371 requirements. SoCalGas/SDG&E state that once CPUC adopts a cost-effectiveness methodology, utilities can consistently calculate the costs and benefits of these Best Practices, including the cost-effectiveness of transitioning from a 5-year leak survey cycle to a 3-year cycle. (SoCalGas/SDG&E February 10, 2017 Comments at 7.)

With respect to SED Staff's suggestion to consider a specific alternative for BP 15, TURN states that there is not any evidence on the record to support surveying of distribution mains and high pressure distribution lines as a cost-effective and effective measure to detect leaks. TURN said that they are not aware of any evidence that correlates leaks and methane emissions with location on mains versus service lines or with distribution pipeline characteristics (e.g., pipeline material, size, pressure). One approach is to consider prioritizing more frequent leak surveys based on distribution mains with different operating pressures. (TURN February 10, 2017 Comments at 4-5.) PG&E states that limiting a survey to a higher pressure line only could actually reduce efficiency due to efficiencies gained by surveying both higher pressure and lower pressure lines in close proximity regionally. PG&E recommends that these surveys be prioritized and driven by risk and leak data, rather than pressures. (PG&E February 10, 2017 Comments at 4-5.)

Clarity

Both CUE and EDF also note that January 2017 proposed BP 15 - Gas Distribution Leak Surveys, BP 16 - Special Leak Surveys, BP 17 - Enhanced Methane Detection, BP 18 - Stationery Methane Detectors, BP 19 - Above Ground Leak Surveys, BP 20 - Quantification and Geographic Tracking, and BP 21 - “Find It/Fix It” (with Timeline and Backlogs) language needs to be improved to establish clearer requirements for applicable utilities. (CUE February 10, 2017 Comments Appendix A, and EDF February 10, 2017 Comments at 9-15.)

7.5. Discussion

In this decision, we do not agree with EDF and CUE’s legal objections to the Best Practices and Compliance Plan Framework that SED Staff has proposed. As PG&E notes, SB 1371 § 975(e)(4) directs the Commission to “[e]stablish and require the use of best practices for leak surveys, patrols, leak survey technology, leak prevention, and leak reduction.” (PG&E February 17, 2017 Comments at 2.) SB 1371 does not state that the Commission must require each operator under its jurisdiction to implement the same detailed set of mandatory Best Practices, as CUE and EDF contend, with little or no ability to tailor the Best Practices to fit an operator’s unique system or to phase in or pilot Best Practices as warranted (*ibid.* at 2).

In addition, the proposed biennial Compliance Plan process ensures that the utilities fulfill the requirements of SB 1371 to implement Best Practices to reduce methane emissions. If the Commission determines a utility’s plan is inadequate or deficient, for example requiring full-scale deployment of a Best Practice an operator proposes to pilot, the Commission can require an operator to make this change as part of the approval process. (*Ibid.* at 2.) In the Best

Practices themselves, we have removed language that may be interpreted to “presume” that exemptions are automatically granted; they will not be.

Due to ongoing Commission oversight and the biennial compliance process, the intent of and requirements in SB 1371 are fulfilled. In this decision, the Commission *establishes* as a matter of fact and of policy what presently constitutes an industry Best Practice and *requires* operators to implement Best Practices through a mandatory mechanism (i.e., by the biennial Compliance Plans). Implementation of a “soft target,” as discussed in Section 10 “Compliance and Evaluation,” provides a further “safeguard” to ensure the reduction of methane leaks. The Commission has wide discretion to implement a range of strategies to implement SB 1371 mandates and need not direct any one process or set of requirements for all participants.

We agree with EDF and CUE, however, that the Best Practices in the January 2017 Revised Staff Proposal can be improved, strengthened, tightened, and clarified to comport with the intent and plain language of SB 1371. The final list of 26 Best Practices represents a distillation and refinement of the initial inventory of 100 Best Practices that served as a starting point for consideration. Through workshops and comments from Parties, the list was narrowed to those that are most practical and could be implemented, and descriptive language was refined to clarify applicability. There are still unknowns to be verified through actual implementation, including effectiveness in reducing emissions and actual costs. Nonetheless, the Commission believes these 26 Best Practices, as a whole, provide policy, planning, training, recordkeeping, leak detection, leak repair and leak prevention requirements that can be optimized for each company’s particular system, and refined further over time and with experience. CPUC staff, in consultation with ARB, and in collaboration with the ongoing industry

technical working group, can significantly improve industry practice while providing reasonable flexibility to support exploration of new technologies that facilitate emissions reductions. As utilities note, this allows operators to apply these Best Practices to their individual systems, and balance emission reduction efforts with what is feasible considering the cost impacts to ratepayers and customers.

7.5.1. Flexibility with Implementing Best Practices

Throughout the process for identifying and establishing Best Practices, there was a continuing tension between Parties who desired to make Best Practices a “requirement” and utilities and ratepayer advocates that argued for flexibility in allowing the companies to use Best Practices most suited for their particular situations and systems. Smaller entities, particularly the ISPs, made strong arguments that they should not be required to adhere to all the practices that might be appropriate for pipelines or distribution system components. As the result of this interplay, and voluminous comments in response to SED Staff’s articulation of a recommended set of Best Practices, we aim to achieve a reasonable balance among the various positions as discussed below.

While we support increased stringency for the Best Practices, we also support some needed flexibility provisions in the Best Practices that allow utilities to submit requests and justification for exemption or modification of specific Best Practices as appropriate. (EDF December 22, 2016 Comments at 6, ISPs December 9, 2016 Comments at 6.) However, we share CUE’s and EDF’s concern that CPUC, and not regulated entities, make feasibility determinations (where allowed by individual Best Practices), (CUE December 22, 2016 Comments at 7; EDF December 9, 2016 at 13 and December 22, 2016 Comments at 8), and support limiting the application of flexibility options to cases where

CPUC has reviewed the data in a Compliance Plan and agrees that the standard Best Practice is infeasible for the utility during that Compliance cycle.

We are sympathetic to EDF's support of "a performance based standard for determining whether particular technologies are equivalent to known best practices," for alternatives allowed under flexibility measures. (EDF December 22, 2016 Comments at 2.) However, this will take time to develop in cooperation with stakeholders and may not be defined until the second phase of this proceeding and/or available until the 2020 cycle.

We agree that alternative measures allowed under the flexibility mechanisms "should be based on practices equal to or superior to the currently known best practices and technologies." (EDF December 22, 2016 Comments at 6.) We also agree with EDF that regulated entities and other stakeholders would benefit from discussion with CPUC of "how and by what standards it plans to review the compliance plans and practices[.]" (*Ibid.*) This will need to be reviewed through a workshop during the second phase of this proceeding and before the first Compliance Plans are due March 15, 2018, as part of the GO 112-F required Safety Plans.

We agree with PG&E that the level of detail and transparency proposed to be required in compliance plans will enable CPUC, ARB, and stakeholders to carefully evaluate a utility's claim that a particular exemption is appropriate in its case. (PG&E December 22, 2016 Comments at 2.) We also agree with PG&E and EDF that these Best Practices must be re-evaluated and potentially made more stringent as more information becomes available. (PG&E July 22, 2016 Comments at 2 and EDF July 15, 2016 Comments at 8.) Soft targets provide a backdrop to ensure that reductions are achieved even if flexibility is provided.

7.5.2. Pilots and R&D Initiatives

We agree with EDF that “[e]ntities that have not yet begun to execute a Best Practice may need to implement the practice at a different pace than [sic] those who have already started, to ensure impact to ratepayers is minimized.” (EDF December 22, 2016 Comments at 4-5.) As EDF notes, adjusting the rate of implementation (rather than the Best Practice itself) can help contain costs. (EDF December 9, 2016 Comments at 22.) We also agree with EDF and the ISPs that beginning with a pilot of a given Best Practice is sometimes appropriate as the first step toward full implementation. (EDF December 22, 2016 Comments at 13; ISPs December 9, 2016 Comments at 6.)

For some leak detection and leak prevention Best Practices, we believe some technologies or practices are not ready for mandatory full-scale deployment due to technological and/or ratepayer affordability challenges in implementing best practices for all utilities. Hence, we will allow companies to propose R&D and/or Pilot programs to gather more information, subject to approval, for specific leak detection and leak prevention Best Practices as identified in the Best Practice table later in this decision. For any proposed R&D and/or Pilot programs, implementation timelines, and evaluation criteria shall be proposed, as appropriate.

For example, although stationary methane detectors best practice (i.e. BP 18) may be ideal for early detection of leaks for compressor stations, gas storage facilities and City Gates, we acknowledge that implementation of stationary methane detectors at certain facilities (i.e., M&R Stations) is still both technologically and financially challenging.

Therefore, we agree with SoCalGas SDG&E that pilots may be needed for BP 18 (SoCalGas/SDG&E Opening Comments December 9, 2016 at 14 and

February 10, 2017 Comments at 6.) We also agree with PG&E that R&D may be needed in addition to pilots to validate that the measurements are correct. We concur with PG&E that additional time may be needed to interpret data and assess operationalization system wide. (PG&E February 17, 2017 Reply Comments at 4.) In addition, incorporating more advanced technologies to support leak data to be transferred to a central database is under development and may not be appropriate for all applications (i.e. M&R Stations). Hence, we expanded BP 18 so that utilities could propose R&D and/or a pilot, subject to approval. Our intent is to review lessons learned and outcomes of any approved R&D and/or pilot programs with the intent to analyze whether full-scale deployment or alternative Best Practices or other research may be desirable.

In other leak detection and leak repair requirements beyond BP 18, we also allow companies to request R&D and/or pilot or other alternative methods to progress on the specific type of best practice requirement. We recommend this flexibility to be available, at a minimum, for the first two compliance plan cycles (i.e., 2018, 2020) due to the developing nature for many new technologies for natural gas leakage surveys and related leak detection best practices, along with nascent implementation of these technologies by most utilities. We recognize that the adopted list and application of individual Best Practices is subject to change over time, as more information is gathered and the impact of this initial effort is assessed in future annual reports and biennial compliance plans.

7.5.3. Overlapping Requirements with Other Best Practices and Other Regulations

In this decision, we disagree with SoCalGas's recommendation to modify best practice language so that any other final or pending regulations would supersede BP 8, BP 18, BP 19, BP 23, BP 24, or BP 25. We agree with EDF that

content of these Best Practices may go beyond other related regulations from DOGGR, ARB, Oil & Gas Regulations or CPUC GO 112F. Just as the Commission has broad authority to implement regulations that are stronger than regulations at federal agencies, the Commission has the authority to implement regulations that go beyond those of “companion” agencies or our own existing applicable GO. This capability gives the Commission needed flexibility to ensure that its existing mandatory best practices can be more stringent over time based on the evolution of best practices and are not inadvertently “diluted” or weakened over time based on other agencies’ regulations that may be updated less frequently. As we discuss below under the leak prevention best practice general discussion section, we have eliminated the specific language from the relevant Best Practices but address the overall issue separately in this decision.

7.5.4. Cost Effectiveness of Best Practices

We do not agree with CUE that SB 1371 somehow prohibits the Commission from considering cost-effectiveness when establishing Best Practices. The apparent rationale for this claim appears to be that if the legislation does not specifically mention cost-effectiveness in the subsection addressing Best Practices (§ 975(e)(4)), the Legislature therefore intended for utilities to implement Best Practices without any regard to cost. As discussed more fully above, however, the Legislature clearly directed the Commission to consider cost and impacts on ratepayers in implementing all portions of the statute, *see* §§ 975(b); 975(e) and (e)(1); 977(d). Considering cost-effectiveness as part of developing and evaluating a respondent’s compliance plan is fully consistent with the intent of the legislation pursuant to (§ 975(b) and 975(e)(1)) and comports with the Commission’s mandate to implement “just and

reasonable” rates. (Please refer to Section 11 for a more thorough discussion of the Commission’s position on cost-effectiveness in this proceeding.)

Because not enough is known at this time about the full cost of many Best Practices or their ultimate effectiveness in reducing methane, the utilities are provided with significant flexibility to put their efforts and resources toward the most promising Best Practices, while allowing for continued research and/or pilot programs where appropriate.

8. Best Practices (Specific)

8.1. Overview

The Commission’s effort to identify industry Best Practices for leak detection, prevention and mitigation initially focused on components of the natural gas system, and, as stated in the procedural history, the first set of Best Practice development workshops brought the Parties together to review potential activities associated with these areas:

- Transmission blowdowns and M&R Station blowdowns;
- Compressor stations – leaks from valves, connections, meters, vents, packing, blowdowns, etc.;
- Storage – control vents, leaks, blowdowns, storage compressors, casings, other sources of leaks and emissions; and
- Customer Meter and PHMSA “minor” releases (threaded connection leaks).

In addition, the workshops addressed potential Best Practices for leak surveys, patrols, leak survey technology, leak prevention, leak reduction, leak repair and required repair times for graded leaks.

In the “Staff Summary of Best Practices Working Group Activities and Staff Recommendations” issued for comment in March 2016, the prospective list of Best Practices had been recategorized into functional areas, in recognition that

some activities were applicable to multiple components of the gas system. The resulting list of Best Practices fell under the following major headings:

- Policies and Procedures BPs 1-8
- Recordkeeping BP 9
- Training BP 10-13
- Experienced, Trained Personnel BP 14
- Leak Detection BPs 15-20
- Leak Repair BP 21
- Leak Prevention BPs 22-26

With the exception of debate over the specifics of BP 1, which would require all companies to create Compliance Plans, the Best Practices associated with Policies, Recordkeeping, Training and Personnel were relatively non-controversial and broadly applicable to all gas companies subject to the Compliance Plan requirement. Therefore, we do not discuss them in detail here. Smaller entities, especially the Independent Storage Providers, in comments and workshop participation sought flexibility or outright exemptions from what were initially proposed to be mandatory Best Practices in the other categories. The ISPs generally utilize small workforces with staff levels set as necessary to safely and reliably operate their facilities. It could be burdensome to require the ISPs to implement some personnel practices better suited to large distribution facilities. However, if this is the case, then they should make a case for this in their respective Compliance Filings.

Later workshops meant to clarify the Best Practice language and applicability resulted in revised SED Staff Recommendations in January 2017, that proposed greater flexibility and allowance for pilot programs or continued research to gather more information about costs and effectiveness of particular Best Practices in certain applications, and also to test newer technologies. As noted elsewhere in this decision, finding the balance between making all 26 Best

Practices mandatory and allowing for flexibility for some of them has been difficult. As discussed above, Intervenor CUE and EDF support mandatory compliance with all Best Practices on one hand, and utilities and, in some cases, ratepayer advocates argue for greater flexibility, allowable exclusions and pilots/research for many of the Best Practices, on the other hand.

The revised listing of Best Practices adopted by this decision (in the table “Summary of Best Practices with Allowed Exemptions and Pilots” on page 95) aims to establish a workable equilibrium between two extremes.

Best Practices in the categories for Detection, Repair and Prevention elicited a greater amount of discussion and debate, which deserve careful deliberation in the following sections of this decision. The outcome of this deliberation is that, for the most part, the largest companies (as determined in the tiered approach described in the Compliance and Enforcement Section) must address the Best Practices for Detection, Repair and Prevention, but have some flexibility to allocate their resources in finding the best mix of operational activities to find and reduce emissions and repair leaks. The companies that represent only a small fraction of total documented leaks are strongly encouraged to employ the full range of Best Practices that are applicable to their operations, but they may present a case for exclusions in their Compliance Plans. Pilots, where most appropriate, may be proposed for specifically identified Best Practices.

Especially in the categories of Detection and Prevention, it may prove over time that one Best Practice is more effective, or cost-effective than another in the same category for a specific utility. Parties’ comments indicate a strong dichotomy between positions on virtually all of the Best Practices in these categories.

The Commission anticipates that the first cycle of compliance will provide additional information that will help refine and focus efforts that will inform a continual process for assessing and updating Best Practices.

Leak Detection

The issues raised by Parties with regard to Leak Detection Best Practices go beyond the frequency of surveys or the use of stationary versus mobile detection techniques and technologies. EDF and CUE consistently argue not just to make the Best Practices mandatory for all companies, and to minimize pilots, but for the Commission to require that detection equipment meet particular standards for sensitivity or frequency of data collection or have capabilities that as yet are not readily available, such as the proposed ability to transfer emission data automatically to a central database.

The following discussion of Parties' positions regarding specific Best Practices in this broad category indicates that the Commission must establish a workable balance among competing claims.

Leak Repair

The fact that Staff and Parties have identified only a single Best Practice in the category of Leak Repair, does not mean there was consensus about BP 21 "Find-it Fix-it" policies. The major disagreements relate to repair timelines and the assertion that SB 1371 requires leaks to be fixed as soon as reasonably possible – and the potential impact on utility backlogs of repairs.

Leak Prevention

As much as with any other category, Best Practices that fall into the prevention heading appear to be either broadly applicable to all companies, (i.e. BP 23 Minimize Fugitive & Vented Methane Emissions), or not at all applicable to some (for example, ISPs are not subject to "Dig-In" problems faced by gas

distribution companies). For this category, the Commission carefully weighs the arguments for exclusions from some Best Practices and value of pilots or continued research.

8.2. Leak Detection Best Practices (BPs 15 – 20)

Note: As for BPs 18 & 19, we have decided to eliminate specific reference to other regulations and address it separately in this decision.

8.2.1. BP 15 – Gas Distribution Leak Surveys

BP 15 Description

Utilities should conduct leak surveys of the gas distribution system every three years, not to exceed 39 months, in areas where GO 112-F, or its successors, requires surveying every five years. In lieu of a system-wide three-year leak survey cycle, utilities could propose and justify in their Compliance Plan filings, subject to Commission approval, a risk-assessment based, more cost-effective methodology for conducting gas distribution pipeline leak surveys at a less frequent interval. However, utilities shall always meet the minimum requirements of GO 112-F, and its successors.

BP 15 – Discussion - Mandatory versus Voluntary Best Practice or Delayed Action

EDF and CUE state that BP 15 should be a mandatory practice and SoCalGas/SDG&E and TURN state that BP 15 should not be a mandatory practice. (EDF February 10, 2017 Comments at 9, CUE February 10, 2017 at 12, SoCalGas/SDG&E February 10, 2017 Comments at 7, and TURN February 10, 2017 Comments at 1.) With respect to this Best Practice, SoCalGas/SDG&E point out that cost estimates to date for all Best Practices have only been rough estimates based on assumptions that may not be consistent with the final SB 1371 cost-effectiveness methodology. As stated earlier when discussing

cost-effectiveness, SoCalGas/SDG&E proffers that once a cost-effectiveness methodology is adopted, utilities can consistently evaluate the costs and benefits of these Best Practices, including the cost effectiveness of transitioning from a five-year leak survey cycle to a three-year cycle. (SoCalGas/SDG&E February 10, 2017 Comments at 7.) PG&E continues to be supportive of moving from a 5-year to a 3-year leak survey cycle but also recommends surveys be prioritized and driven by risk and leak data. (PG&E February 10, 2017 Comments at 4.)

TURN recommends that the Commission not mandate BP 15. TURN also recommends the Commission order the collection of any necessary additional evidence and data and for the Commission to delay any decision on BP 15 until the relevant data is collected and analyzed. We disagree with TURN that the Commission should delay action on BP 15 until it collects additional evidence. (TURN February 10, 2017 Comments at 2.)

In reply comments, EDF strongly maintains that BP 15 must be a mandatory Best Practice and claims that a three year leak cycle has been established as a best practice pursuant to § 975(e)(4). EDF also argues that the statute specifically requires the Commission to set a Best Practice for “leak survey” so if the Commission was inclined to allow an equivalent substitution, it must be a leak survey practice substitution. (EDF February 17, 2017 Reply Comments at 3.) SoCalGas/SDG&E reply that they disagree with EDF and CUE recommendations for a three-year leak survey cycle. (SoCalGas/SDG&E February 17, 2017 Reply Comments at 2.)

We conclude that this will be a mandatory best practice for all applicable utilities but with allowable alternatives as discussed below. This Best Practice does not impact the CPUC’s existing broader annual survey cycle requirements

for some parts of the distribution system according to GO 112-F. We expect applicable utilities to clearly address this best practice in their Compliance Plans.

Allowable Alternatives

We also concur with CUE, EDF and SoCalGas/SDG&E that any allowable alternative should be a leak detection based alternative. Specifically, any measures to reduce leakage backlog would not be an allowable alternative. (CUE February 10, 2017 Comments at 14, EDF February 10, 2017 Comments at 10 and SoCalGas/SDG&E February 17, 2017 Reply Comments at 2.) This leak detection Best Practice establishes a requirement for leak survey intervals of three years for all distribution pipelines formerly under the five-year leak survey requirement, unless the utility can justify more effective leak survey cycles at a less frequent interval using a risk assessment approach. We have allowed for this alternative because we believe different leak survey cycles may be appropriate for various districts or areas of a utilities' distribution system based on risk considerations of leak history, pipe material and age, soil conditions, etc.

As for denying reducing leakage backlog as an alternative for this leak detection/survey best practice, reducing the backlog of known leaks would typically be done by repairing those leaks. Hence, that measure is more appropriately addressed for the leak repair best practice, BP 21.

Data Collection

Finally, although we disagree with TURN's request to delay this best practice altogether until additional data and information is gathered, we do find TURN's specific recommendations on the types of data needed to be gathered useful to monitor and assess the effectiveness of this voluntary best practice to evaluate whether this type of best practice should be considered as a mandatory best practice in the future. PG&E responded to TURN's comments

recommending the Commission order PG&E to collect data on the correlation between leaks and emissions, and certain distribution pipeline characteristics. PG&E states that as explained by PG&E in its GRC discovery (GRC-2017-PhI_DR_TURN_042_Q08), the exact source of a leak can only be verified during excavation and repair. We acknowledge PG&E's statement that "Since not all leaks are repaired and, for those that are, repair times vary, this would be an incomplete data set and not a valid basis for inferring a correlation." Yet, pursuant to BP 21, "Find It/Fix It" Leak Repair, mandatory requirement to repair all leaks, we believe this data may be useful and order its collection. (PG&E February 17, 2017 Reply Comments at 4.)

Specifically, we believe TURN's suggestion will help us determine an appropriate future mandatory leak survey frequency for distribution mains and service pipelines. Thus, we require utilities to collect data and information that either is utilized or can be utilized in a risk-assessment based study to determine cost-effective leak survey activities and frequency. This data shall be included in future Annual Emissions Inventory Reports with the detailed reporting requirements, directed by Joint Staff. Essentially, we expect utilities to capture and utilize data with the expectation that it will be useful in determining what, where, when and how to reduce leaks in a cost-effective manner. As an example of types of data, TURN recommends collection of:

- Mileage and characteristics of distribution mains (size, pipe material, operating pressure);
- Number of services surveyed and leak find rates as a function of line item cost differentiated by grade of leak;
- Nature and occurrence of leaks differentiated by types of distribution pipe;

- Factors impacting the grading characteristics of a leak including historical leak data and other risk-assessment based data; and
- Data that correlates leaks and methane emissions with location on mains versus service lines or with distribution pipeline characteristics (e.g., pipe material, size, pressure).

8.2.2. BP 16 – Special Leak Surveys

BP 16 - Description

Utilities shall conduct special leak surveys, possibly at a more frequent interval than required by GO 112-F (or its successors) or BP 15, for specific areas of their transmission and distribution pipeline systems with known risks for natural gas leakage. Special leak surveys may focus on specific pipeline materials known to be susceptible to leaks or other known pipeline integrity risks, such as geological conditions. Special leak surveys shall be coordinated with transmission and distribution integrity management programs (TIMP/DIMP) and other utility safety programs. Utilities shall file in their Compliance Plan proposed special leak surveys for known risks and proposed methodologies for identifying additional special leak surveys based on risk assessments (including predictive and/or historical trends analysis). As surveys are conducted over time, utilities shall report as part of their Compliance Plans, details about leakage trends. Predictive analysis may be defined differently for differing companies based on company size and trends.

BP 16-Discussion

Type of Leak Survey

Although CUE suggested specific pipe materials (e.g., cast iron, pre-1940 steel pipe, pre-1985 Aldyl-A pipe, copper services installed from the 1930s to late 1960s, and plastic tee caps) to be the focus of special leak surveys (CUE February 10, 2017 Comments at 15 and Appendix A at 23-24.), we believe there

are other risks that could be addressed by special leak surveys to minimize methane emissions including pipeline integrity risks and geologic or soil conditions risk factors. To be clear, we do agree that these specific pipe materials should be included as factors in pipeline integrity risk assessments. Since this leak detection Best Practice requires utilities to conduct special leak surveys, possibly more frequently than GO 112-F or BP 15, in coordination with their integrity management and other utility safety programs and requires these special leak surveys to be predicated on risk assessments (including predictive and/or historical trends analysis), this measure will allow surveying of areas with known types of risks and, in the future, any additional types of risks that the utilities become aware of. This Best Practice also allows for predictive analysis to be defined differently for differing companies based on company size and trends. Related to this leak detection practice is the understanding that pipeline sections with a high leak frequency should be replaced or modified to make them safe (for example older pipe materials exhibiting corrosion leaks or defective fittings.)

Predictive Spatial Analytics

We acknowledge EDF's argument that predictive spatial analytics should be researched and employed to predict where investments are best made and where pipes are going to leak. (EDF February 10, 2017 Comments at 10-11.) Yet, the Commission also concurs with SoCalGas/SDG&E that each utility's system is unique and utilities should be able to perform predictive analysis based on their own unique systems. (SoCalGas/SDG&E February 17, 2017 Comments at 2.) The Commission also notes PG&E's comments that the predictive analysis report referenced by EDF does not validate the effectiveness of predictive analysis. (PG&E February 17, 2017 Reply Comments at 4.) It is also noted that the

predictive analysis report included a graph showing the predictive analysis study was based on customer notifications of leakages as higher detectors than leak survey results. We are not convinced that these factors into this predictive spatial analytics tool apply directly to predicting leakages in large California natural gas utilities as it is not known whether leakages are discovered in similar proportions by customer notifications and whether this impacts the tool's methodology for detecting leakages. Therefore, the referenced study results may not be directly applicable to these large California utilities.

8.2.3. BP 17 – Enhanced Methane Detection

BP 17 - Description

Utilities shall utilize enhanced methane detection practices (e.g., mobile methane detection and/or aerial leak detection) including enhanced gas speciation technologies.

BP 17 - Discussion - Single Standard

This Best Practice mandates utilities to use enhanced methane detection practices including gas speciation technologies. This Best Practice does not require specific practices or technologies as we believe utilities should be allowed to utilize practices and technologies that are most suitable for their gas systems and geographical areas. Hence, we do not adopt EDF's recommendation to set a standard for these nascent technologies. (EDF February 10, 2017 Comments at 11-12.) We agree with SoCalGas/SDG&E that it is not reasonable to set a single standard for various enhanced methane detection technologies and methods which would not account for the uniqueness of each utility, particularly at this time as the implementation of many of these technologies is nascent. (SoCalGas/SDG&E February 17, 2017 Comments at 3.) This enhanced methane detection best practice requirement ensures that applicable utilities implement

new technologies but allows utilities to propose further R&D and/or pilot programs. We believe this best practice requirement will further the industry's technological capabilities to detect methane for the purposes of reducing methane emissions from natural gas infrastructure while ensuring that affordability is considered.

8.2.4. BP 18 – Stationary Methane Detectors

BP 18 – Description

Utilities shall utilize Stationary Methane Detectors for early detection of leaks. Locations include: Compressor Stations, Terminals, Gas Storage Facilities, City Gates, and M&R Stations (M&R above ground and pressures above 300 pounds per square inch gauge (psig) only). Methane detector technology should be capable of transferring leak data to a central database, if appropriate for location.

BP 18 Discussion - Scope

As SoCalGas/SDG&E point out, clarification is needed on the scope of M&R stations to be included in this best practice. (SoCalGas/SDG&E February 10, 2017 Comments at 6-7.) We concur with EDF's argument that any decision to remove components from a stationary monitoring requirement must be based on leak/emissions rates. (EDF February 17, 2017 Reply Comments at 3.) Based on potential classifications provided by SoCalGas/SDG&E, EDF's argument, and based on the advice of ARB Staff that the M&R emission factors may significantly be reduced, this Best Practice shall apply to Transmission M&R stations and above-ground Distribution M&R Stations with pressures above 300 psig. (SoCalGas/SDG&E February 10, 2017 Comments at 6-7.)

M&R Stations (Above and Below Ground)

We disagree with SoCalGas/SDG&E's recommendation to exclude M&R Stations once high-bleed pneumatic device replacements have been completed. (SoCalGas/SDG&E February 10, 2017 Comments at 6.) SED Staff has consulted with ARB and although emission factors may be adjusted significantly for M&R stations for SB 1371 annual emissions reporting, there are still intermittent and low-bleed pneumatic M&R stations that continue to emit methane. We agree with SoCalGas/SDG&E that this best practice should not be applicable to below-ground M&R station vaults if there are any safety hazards to utilizing this technology due to the lack of vents in these facilities. (SoCalGas/SDG&E February 10, 2017 Comments at 6.)

Substitution of Other Best Practices

We agree with EDF and do not accept SoCalGas/SDG&E's recommendation to only require either BP 18 or BP 19 as both the technologies and methodologies for detection leaks are varied by these two Best Practices and are therefore not redundant. (EDF February 17, 2017 Reply Comments at 2-3.) SoCalGas/SDG&E February 10, 2017 Comments at 6.)

Centralized Leak Database and "Continuous" Monitoring

We do not accept EDF and CUE's arguments that the Commission should rewrite BP 18 to require stationary "continuous" monitoring and require each utility to present its plan for a centralized leak database, and how all the necessary data will be included. (EDF February 10, 2017 Comments at 12-13 and CUE February 10, 2017 Comments Appendix A at 24.) The term "continuous" is a vague and potentially burdensome requirement as it is unclear how often leak survey data should be collected to be most effective. Additionally, information

about a centralized leak database is more appropriately reviewed as part of the utilities' Compliance Plans.

8.2.5. BP 19 – Above Ground Leak Surveys

BP 19 – Description

Utilities shall conduct frequent leak surveys and data collection at above ground transmission and high pressure distribution (above 60 psig) facilities including Compressor Stations, Gas Storage Facilities, City Gates, and M&R Stations (M&R above ground and pressures above 300 psig only). At a minimum, above ground leak surveys and data collection must be conducted on an annual basis for compressor stations and gas storage facilities.

BP 19- Discussion - Leak Survey Frequency

We agree with EDF that this Best Practice could be improved by including a specific leak survey frequency for above ground facilities. Hence, we have modified this best practice to require annual above ground leak surveys, at a minimum, for compressor stations and gas storage facilities. These facilities were chosen since they are known to be locations where the operations requirements typically require or have as a byproduct some amount of natural gas emissions. We are cognizant of costs impacts of requiring additional surveying and believe this requirement will not be too burdensome since there are a limited number of these facilities and other annual inspections of equipment at these facilities are already required. (EDF February 10, 2017 Comments at 13.) We also acknowledge SoCalGas/SDG&E's comment that flexibility in this Best Practice helps utilities avoid redundant leak survey requirements where other pending regulations may provide specific test frequency. (SoCalGas/SDG&E February 17, 2017 Reply Comments at 3.)

8.2.6. BP 20 – Quantification and Geographic Tracking

BP 20a – Quantification Description

Utilities shall develop methodologies for improved quantification of leaks from the gas systems. Utilities shall file in their Compliance Plan how they propose to address quantification. Utilities shall work together, with Joint Staff, to come to agreement on a similar methodology to improve emissions quantification and geographic evaluation and tracking of leaks to assist demonstration of actual emissions reductions.

BP 20 – Quantification Discussion

This leak detection Best Practice requires utilities to develop methodologies for improved quantification of leaks. This Best Practice also requires utilities to work together, with Joint Staff, to come to agreement on a similar methodology to improve emissions quantification of leaks to assist demonstration of actual emissions reductions. Improved quantification technologies are very much needed in the industry. Quantifying the amount of natural gas emitted from a leak is dependent on equipment sensitivities and the ability to utilize equipment successfully to measure leakage. Therefore, it is critical to improve accurate emissions inventory data as lessons learned from reviewing Annual Emissions Inventory Report data is that much of the inventory is based on estimations.

More Analysis Needed

As discussed in Section 5.6 regarding the development of EFs, we acknowledge SoCalGas/SDG&E's comments that additional analysis may be needed regarding emissions estimations versus measurement (and quantification) methodologies, particularly as to whether direct measurement

methods will yield better estimates as it is a function of many factors.

(SoCalGas/SDG&E February 10, 2017 Comments at 4.)

BP 20b – Geographic Tracking Description

Utilities shall develop methodologies for geographic evaluation and tracking of leaks from the gas systems. Utilities shall work together, with Joint Staff, to come to agreement on a similar methodology to improve geographic evaluation and tracking of leaks to assist demonstrations of actual emissions reductions. Leak detection technology should be capable of transferring leak data to a central database in order to provide data for leak maps. Geographic leak maps shall be publicly available with leaks displayed by zip code or census tract.

BP 20b – Geographic Tracking Discussion

This Best Practice also requires utilities to work together, with Joint Staff, to come to agreement on a similar methodology to improve geographic tracking and evaluation of leaks to assist demonstrations of actual emissions reductions. This Best Practice recommends that leak detector technologies are capable of transferring leak data to a central database in order to provide data for leak maps.

Street Level Views

Although we agree that increasing transparency about methane emissions to the public is important, we do not support EDF's recommendation to reword the Best Practice to state that "geographic leak maps shall be publicly available with leaks displayed on a street level view, and with a zoom function to see intermediate and larger city wide views." We believe requiring geographic leak maps to be publicly available with leaks to be displayed by zip code or census track is sufficiently transparent. (EDF February 10, 2017 Comments at 14.)

Please see Section 5.6.1 “Confidentiality” for a more in depth discussion of this topic.

8.3. Leak Repair Best Practice (BP 21)

8.3.1. BP 21 – “Find It/Fix It”

BP 21 - Description

Utilities shall repair leaks as soon as reasonably possible after discovery, but in no event, more than three years after discovery. Utilities may make reasonable exceptions for leaks that are costly to repair relative to the estimated size of the leak.

BP 21 - Discussion

As the only leak repair Best Practice, this “find-it/fix-it” Best Practice applies to all leaks. This Best Practice requires utilities to repair all leaks within a maximum of three years as of discovery, allowing for reasonable exceptions. We have decided against requiring a certain size threshold value to be utilized to determine whether to fix a leak because threshold determination is more germane to quantification. Leak quantification methodologies will be studied and improved, pursuant to BP 20. Additionally, the Commission provides guidance regarding exemption levels in Compliance Plan rulings and to address the need for data gathering on costs, leak volumes and reporting of those data in future annual reports.

Backlogs

Once the current backlog of leaks has been repaired and ongoing repair of newly discovered leaks has become standard practice, any remaining backlog will consist only of leaks the Commission has determined cannot be repaired within reasonable conditions or costs. Because we have modified the Best Practices recommended by SED Staff to remove language that addresses

concerns or activities that are applicable only at the start of the SB 1371 natural gas leak abatement program, we have deleted reference to backlogs in the BP 21. Rather than include backlogs in the Best Practices per se, we will simply require utilities to eliminate their backlog of leaks within three years of the effective date of this decision, with the same exemption for cost prohibitive repairs included in BP 21. This is an important near-term step that can significantly reduce methane emissions.

Exceed GO 112-F Requirements

We agree with SoCalGas/SDG&E's comment that this Best Practice's intent is to exceed requirements of GO 112-F. (SoCalGas/SDG&E February 10, 2017 Comments at 5.) Additionally, we partially agree with EDF that the Commission should require utilities to repair all leaks (not including the extremely expensive and small underground leaks) but we do not adopt EDF's recommendation to require utilities to focus on developing a threshold for underground leak repairs. (EDF February 17, 2017 Reply Comments at 4.)

Exemptions

We do not accept PG&E's specific recommendation to allow an exemption if other emission reduction strategies are presented to repair all Grade 3 leaks within a given timeframe and allow an alternative approach. (PG&E February 10, 2017 Comments at 4.) As stated earlier, we believe repairing leak backlogs is an important short-term requirement. But also, we believe that for the longer-term, it is prudent to change the paradigm in the industry to repair leaks as soon as reasonably possible after discovery to prevent additions to the backlog of unrepaired leaks.

PG&E Test Year 2017 GRC Settlement

The Commission also appreciates that TURN promoted Clause 3.2.1.1.3 in PG&E's Test Year 2017 GRC Settlement which also impacts leak repairs and is pending approval. (TURN February 10, 2017 Comments at 4.) In that clause, PG&E agrees to evaluate the feasibility of developing an assessment methodology to determine the likelihood of [Underground Grade 3 leaks] becoming more serious over time. PG&E also agrees to use historical leak data and the DIMP risk model factors to determine their impacts on the likelihood of Grade 3 leaks becoming Grade 2+, 2 or Grade 1 leaks over time. The clause also includes the following agreements from PG&E: "Regardless of the determination of likelihood that a Grade 3 leak will remain the same or become more serious over time, PG&E shall repair Grade 3 leaks within the timeline for repair mandated in the Phase 1 R.15-01-008 decision. If a grade 3 leak becomes a Grade 2+, 2, or Grade 1 over time, it shall be repaired within the timeline for that grade as mandated by the R.15-01-008 Phase 1 decision." (TURN February 10, 2017 Comments at 4, referencing "Joint Motion for Adoption of Settlement Agreement," filed August 3, 2016 in A.15-09-001.) The Commission determined this provision of the settlement to be reasonable and adopted it as part of the May 11, 2017, GRC decision D.17-05-013 (page 143).

Timeline

We agree with EDF that BP 21 changes to specifically require § 975(e)(2) "as soon as reasonably possible" language as the determination as to when leaks must be fixed will improve the best practice. At the same time, we believe SoCalGas/SDG&E correctly observe that CUE's proposal to define "as soon as reasonably possible" as requiring a repair no later than three months after a leak is discovered or not later than 12 months if the repair may require authorization

from local government does not address the cost implications to ratepayers. (SoCalGas/SDG&E February 17, 2017 Reply Comments at 3 and CUE February 10, 2017 Comments Appendix A at 25-26.)

The adopted BP 21 requires leaks to be repaired as soon as reasonably possible after discovery within three years. At the same time, we also agree with SoCalGas/SDG&E that EDF's request to delete the "reasonable exception" language from the Best Practice is problematic as there are situations outside the utilities' control that might delay leak repairs and the reasonable exception is intended to account for those situations. (SoCalGas/SDG&E February 17, 2017 Reply Comments at 3 and EDF February 10, 2017 Comments at 14.)

Super Emitter Survey

We agree with PG&E and EDF that alternative approaches, such as super emitter survey program being piloted at PG&E, may yield greater emission reductions and be a more cost-effective solution for emission reductions. (PG&E February 17, 2017 Reply Comments at 5 and EDF February 17, 2017 Reply Comments at 4.) EDF makes a sound argument that this alternative approach should not replace BP 21 as a leak repair Best Practice as it may be more appropriate as an alternative methodology for BP 16 special leak surveys. We acknowledge EDF's request to allow PG&E to continue with this R&D (and potentially use it as an alternative leak detection practice in the future).

Threshold Values

Given all the uncertainty in mitigation costs and leakage and emissions data accuracy, we are unable to foresee that a threshold value can be easily determined in the near future. Leaks should be repaired, but utilities should use their best judgment in deciding which leaks may not be economical to repair immediately.

8.4. Leak Prevention Best Practices (BPs 22-26)

8.4.1. BP 23 – Minimize Emissions From Operations, Maintenance and Other Activities

BP 23 – Description

Utilities shall minimize methane emissions from operations, maintenance and other activities, such as new construction or replacement, in the gas distribution and transmission systems and storage facilities. Utilities shall replace high-bleed pneumatic devices with technology that does not vent gas (i.e., no-bleed) or vents significantly less natural gas (i.e. low-bleed) devices. Utilities shall also reduce emissions from blowdowns, as much as operationally feasible.

BP 23 – Discussion

Most natural gas companies have gas systems containing large volumes of methane. Large amounts of fugitive and vented emissions from operations, maintenance and other activities, along with unforeseen catastrophic releases, can negate the methane reductions by other measures and significantly increase GHG emissions. This leak prevention Best Practice focuses on minimizing fugitive and vented methane emissions including those from catastrophic releases, high-bleed pneumatics and blowdowns. This Best Practice requires replacement of high-bleed pneumatic devices and also requires reduction of blowdown emissions.

Although parties generally did not comment on the latest version of BP 23, we believe the language, including the title, needs to be modified in order to clarify the intent of this best practice. We have incorporated a mandatory requirement to minimize emissions overall for operations, maintenance and other activities. As with other adopted Best Practices, cost-effectiveness and

technical feasibility are important considerations for utilities when implementing this best practice. Additionally, this and other Best Practices must be implemented consistent with Operations & Maintenance (O&M) safety, system integrity and reliability requirements.

Finally, although we have deleted from this specific Best Practice the recommendation for utilities to propose R&D or pilot programs specific to determination of cost-effectiveness and technical feasibility of blowdown mitigations for distribution pipelines (at or below 60 psig) as part of their Compliance Plans, we still encourage utilities to consider doing so.

8.5. Summary of Best Practices with Allowed Exemptions and Pilots

In this decision, we adopt the four guiding principles as discussed above and the following mandatory Best Practices with allowed exemptions and pilots, and related specifications, as detailed in Appendix B (subject to approval via Biennial Compliance Plans).

(go to next page)

Summary of Best Practices for Natural Gas Leak Abatement Program (with Allowed Exemptions, Pilots/R&D & Utility Class Classifications)				
CATEGORY	BP #	TITLE	EXEMPTIONS?*	PILOTS/R&D ALLOWED?*
Policies and Procedures	1	Compliance Plan	No	No
Policies and Procedures	2	Methane GHG Policy	No	No
Policies and Procedures	3	Pressure Reduction Policy	No	No
Policies and Procedures	4	Project Scheduling Policy	No	No
Policies and Procedures	5	Methane Evacuation Procedure	No	No
Policies and Procedures	6	Methane Evacuation Work Order Policy	No	No
Policies and Procedures	7	Bundling Work Policy	No	No
Policies and Procedures	8	Company Emergency Procedures	No	No
Recordkeeping	9	Recordkeeping	No	No
Training	10	Minimize Uncontrolled Methane Emissions Training	No	No
Training	11	Minimize Methane Emissions Policies Training	No	No
Training	12	Knowledge Continuity Training Programs	No	No
Training	13	Performance Focused Training Programs	No	No
Experienced, Trained Personnel	14	Formal Job Classifications	B, C	No
Leak Detection	15	Gas Distribution Leak Surveys	C	No
Leak Detection	16	Special Leak Surveys	C	Yes
Leak Detection	17	Enhanced Methane Detection	B, C	Yes
Leak Detection	18	Stationary Methane Detectors	B, C	Yes
Leak Detection	19	Above Ground Leak Surveys	B, C	No
Leak Detection	20a	Quantification	B, C	Yes
	20b	Geographic Tracking	C	Yes
Leak Repair	21	"Find-It/Fix-It"	C	No
Leak Prevention	22	Pipe Fitting Specifications	B, C	Yes
Leak Prevention	23	Minimize Emissions from Operations, Maintenance and Other Activities	No	Yes
Leak Prevention	24	Dig-Ins / Public Education Program	C	No
Leak Prevention	25	Dig-Ins / Company Standby Monitors	No	No
Leak Prevention	26	Dig-Ins / Repeat Offenders	C	No
*See description of Utility Class Categories A, B, and C below. No exemptions = Mandatory. If Class B or C are listed, requests for exemptions are subject to Safety & Enforcement Division review and approval.				
** Pilot and/or R&D program may be proposed, subject to Commission approval.				
Utility Class Categories				
Class A: Utilities with total annual methane emissions equal to or greater than 500,000 Mscf.				
Class B: Utilities with total annual methane emissions between 50,000 and 500,000 Mscf.				
Class C: Utilities with total annual methane emissions equal or below 50,000 Mscf.				

(Please see Section 10, “Compliance and Enforcement” for a discussion about utility classifications.)

Other Specifications:

1. Most Best Practices including most Leak Detection Best Practices (e.g., 16 through 20) and the Repair BP 21, are mandatory as recommended by CUE and EDF. In most cases, the words “should” are replaced with “shall” to give directives more force.
2. Language allowing for exemptions in the Best Practices themselves is removed and is instead included in other parts of the decision. (In some instances, some language is duplicative with SED Staff’s categorization proposal.) Class categories have been refined to allow a request for exemption in certain instances. (See above.)
3. Class B Utilities will not be allowed exemptions from two Leak Detection Best Practices: BP 15 (Gas Distribution Leak Surveys) or BP 16 (Special Leak Surveys) or the Leak Repair BP 21.
4. BP 3-Pressure Reduction Policy, BP 4-Projects Scheduling Policy, BP 5-Methane Evacuation Procedures, and BP 6-Methane Evacuation Work Orders Policy, does not apply to companies with natural gas distribution infrastructure that are only operated at or below 60 psig. These Best Practices have also been deleted from the Class C request for exemption list. This will make these Best Practices requirements for all companies except West Coast Gas and Alpine.
5. BP 15-Gas Distribution Leak surveys applies only to utilities with distribution pipelines; BP 25-Dig-Ins/Standby Monitors is applicable only to utilities with transmission pipelines.
6. Substitutions are permitted if the CPUC reviews a proposed Compliance Plan and agrees that the standard Best Practice is infeasible for the utility for that Compliance Plan cycle. Any substitute measures that are also Best Practices are only appropriate for Best Practices within the same category. All

substitute measures shall provide equivalent or better performance than the standard Best Practice.

7. Content of BP 8-Company Emergency Procedures, BP 18-Stationery Methane Detectors, BP 19-Above Ground Leak Surveys, BP 23-Minimize Fugitive & Vented Methane Emissions, BP 24-Dig-Ins/Public Education Programs, or BP 25-Dig-Ins/Company Standby Monitors may go beyond other related regulations from DOGGR, ARB, Oil & Gas Regulations or CPUC GO 112-F and its successors.

9. Targets

9.1. SB 1371 Requirements and Other Recently Enacted Legislation

After the filing of comments by parties on the concept of “targets,” on September 19, 2016, the Governor signed SB 1383 which required “...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 also 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.”⁴² In addition, SB 32, which sets a 2030 greenhouse gas reduction below 1990 levels, became a law in 2016.⁴³ Both of these statutes build upon California’s 2006 landmark statute, AB 32, which required the reduction of GHG emissions to 1990 levels by

⁴² 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.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1383.

⁴³ California Global Warming Solutions Act of 2006: emissions limit. SB 32, Pavley, Reg. Sess. 2015-2016. (2016).

2020.⁴⁴ Although neither statute has been explicitly scoped into a Phase 1 or Phase 2 of this proceeding, since SB 1383 directs ARB to develop plans to reduce statewide emissions reduction, we address it here.

9.2. Parties' Comments

Hard Targets

All parties agree that the CPUC is not legislatively required to establish hard targets in this rulemaking. EDF states that the current emissions reports are far from ideal and not accurate or transparent enough to create meaningful and enforceable targets. ORA recommends that given the need for more robust emissions data, the CPUC and ARB first focus on the establishment and implementation of best practices that are proven to increase system safety, reduce risks, and are cost-effective, and not focus on a hard percentage goal at this time. ORA also recommends that emission reduction projections be reconsidered once the utilities' June 2016 reports have been analyzed and vetted by Joint Staff. The Joint Utilities (SoCalGas/SDG&E/Southwest Gas) agree with ORA and EDF with the lack of a technical basis for establishing targets. PG&E agrees that more information is needed to determine a baseline and establish meaningful targets and that accurate and transparent data are the foundation for setting meaningful methane emissions reduction targets. The Joint Utilities believe an arbitrary hard target percent reduction goal is inappropriate due to the variability in measurement and activities that may not be within the utilities' control. The Joint Utilities state it is unclear how an operator could demonstrate an emission reduction for many of the emission sources against a hard target,

⁴⁴ California Global Warming Solutions Act, AB 32, Reg. Sess. 2005-2006 (2006)

especially for the top three aggregated sources of emissions (i.e., pipeline leaks, blowdowns, and meter set assemblies). EDF replies that it agrees with the Joint Utilities that at this time setting hard emissions targets is not the best option for enforcement of the emissions reductions. EDF argues the overall target must be minimizing emissions. EDF and CUE recommend ARB set California-wide goals for methane emissions reductions.

Interim Targets/Goals

EDF, with CUE's support, claims quantitative targets should represent interim goals, useful for tracking utility progress. The Joint Utilities state the 40% target appears arbitrary and inconsistent with other goals in other GHG reduction programs, such as ARB's Short-Lived Climate Pollutant (SLCP) Strategy. EDF disagrees with this assertion. EDF argues that targets should be informative and not compliance based. EDF also believes targets will have to be reevaluated as new technologies find more leaks, and the number of unfound leaks decreases. PG&E agrees with EDF that targets should be updated as needed to reflect up to date verified data and technologies. ISPs strongly recommend that maintaining existing minimal ISP emissions be their target along with identifying cost-effective meaningful methane emissions reductions. The ISPs state that the comparably recent infrastructure and effective technology and measures already being used at the ISP facilities needs to be taken into account when developing emission and leak abatement requirements. ORA recommends that if a situation arises where the implementation of natural gas safety plans and the reduction of emissions levels are not complementary activities, that safety activities have primacy over efforts to reduce emission levels.

9.3. Discussion

Although hard targets are not possible in the short-term, we agree with CUE and EDF that an interim or “soft” target should be established to ensure the necessary reductions occur, particularly given the fact that the present Best Practices include significant flexibility (EDF July 15, 2016 Comments at 2, 3, 6, 7, 10; and CUE July 22, 2016 Comments at 1-2.) There must be criteria for evaluating the submitted compliance plans, and evaluating their progress toward a soft target is one of the criteria. Although we are not sure that the utility-specific targets advocated by multiple commenters are appropriate or easily implementable (ISPs July 15, 2016 Comments at 9; EDF July 15, 2016 Comments at 6; and PG&E July 22, 2016 Comments at 5-6), we agree with PG&E that if sub-targets are developed for individual utilities, they “should be updated as needed to reflect up to date verified data and technologies,” subject to the Commission’s and ARB’s review and approval[.] (PG&E July 22, 2016 Comments at 2.)

While we view a soft target as most viable in the near-term, we disagree with Joint Utilities, EDF, and CUE that a hard target would never be permissible or appropriate (SoCalGas/SDG&E July 22, 2016 Comments at 2-3; EDF July 15, 2016 Comments at 1-2; and CUE July 22, 2016 Comments at 1.) We disagree with the Joint Utilities that a future hard target would not be appropriate because of variability and circumstances that utilities do not control (SoCalGas/SDG&E July 15, 2016 Comments at 4); these can be taken into account as necessary. We also disagree with EDF and CUE that SB 1371 precludes establishment of a hard target for methane reductions because of its directive to “minimize” emissions (EDF July 15, 2016 Comments at 1, 4, 7, 10; and CUE July 22, 2016 Comments at 1.) The statutory directive to “minimize” concerns safety (“Minimize leaks as

a hazard to be mitigated”), not GHG emissions.⁴⁵ The relevant statutory directive, as discussed in the “Cost-effectiveness and Technological Feasibility” sections above, is to “reduce emissions of natural gas ... to the maximum extent feasible in order to advance the state’s goals in reducing emissions of greenhouse gases pursuant to [HSC Div. 25.5].”⁴⁶ We agree with EDF that this statutory text supports CPUC’s ability to set targets below 40% reduction (EDF July 15, 2016 Comments at 7), but not that it precludes CPUC from setting firm compliance targets at all.

SB 1383 sets an economy-wide methane reduction target of 40% below 2013 levels by 2030, to be achieved through ARB’s implementation of its Short-Lived Climate Pollutant Strategy. Although SB 1383 is not formally part of this rulemaking, we view the overall 40% target as an important consideration and view SB 1383 as providing a basis to potentially set a hard target in the future. ARB will need to ensure the reductions targets are met for methane and must evaluate if current approaches will achieve that target. As such, it is appropriate to consider targets in Phase Two in this proceeding to meet the methane reduction goals without a need for additional regulatory approaches for the utilities. This approach would be the most efficient way to ensure the state meets SB 1383 requirements. This approach would not prevent reductions beyond the 40% target; we acknowledge, as noted above, that SB 1371 requires reductions to the “maximum extent feasible.”⁴⁷ Phase Two is the appropriate place for this discussion as further information on emissions, emission

⁴⁵ See § 975(b)(1), referencing § 961(d)(1).

⁴⁶ See § 975(b)(2).

⁴⁷ See § 975(b)(2).

reductions, and costs are collected. Flexibility should be given to utilities in the first compliance period since this timeframe will involve a significant learning curve as best practices evolve. However, meaningful reductions are still required during this period. Hard targets could be set for 2030 based on the information in the 2020 reports, additional emission factor revisions, and other data.

We support Joint Staff's recommendation that the compliance plans include information on how each party plans to achieve a 40% reduction below 2013 levels by 2030, what level of reduction would be necessary by 2020, and how they plan to achieve the 2020 reduction level. Because ISPs' underground storage facilities are relatively new, we acknowledge that many ISPs already incorporate measures to reduce emissions. Therefore, the 40% soft target may not appropriately apply to ISPs. However, we are reluctant to eliminate this compliance plan requirement now until we evaluate the results of the first filing in March 2018. The Commission will be able to rely on its review of ISP compliance plans to ensure ISPs are taking appropriate feasible and cost effective measures to continue to minimize methane emissions and leaks.

Although the target the party sets for itself in 2020 would not be enforceable, the planned actions in the compliance plans would be. Joint Staff recommends a hard target be considered during Phase Two of the proceeding and that SB 1383 be scoped into the proceeding at that time.

10. Compliance and Enforcement

10.1. SB 1371 Requirements

According to SB 1371, "The rules and procedures, including best practices and repair standards, shall be incorporated into the safety plans required by

Section 961 and the applicable general orders adopted by the commission.”
(§ 975 (f)).

Further, SB 1371 states that one of the dual goals of rules and procedures adopted in this proceeding, along with reducing gas emissions, is to “minimize leaks as a hazard to be mitigated” pursuant to § 961 (d) (1) and consistent with federal rules and the CPUC’s GO 112 -E and their successors.

§ 961 describes the Gas Safety Plans required by SB 705 (2012). The section requires utilities to develop and implement these plans. (§ 961(b).)

§ 961 (b)(4) requires each gas corporation to periodically review and update their plans, and the Commission shall review and accept, modify, or reject an updated plan.

Note: GO 112-F (approved in D.15-06-044) included this provision for Annual Reports:

1. Each Utility Operator must submit a Gas Safety Plan, as codified by Pub. Util. Code §§ 961 and 963, and as ordered by the Commission in D.12-04-010.
2. Each Utility Operator must make any modifications to its Gas Safety Plan identified by the Commission’s Safety and Enforcement Division, or its successor.⁴⁸

10.2. Staff Revised Proposal

As described in the January 19, 2017 Revised Staff Proposal, SED Staff recommends that the Commission make all but one of the Best Practices mandatory but provide flexibility within the Best Practices and allow a subset of companies to request exemptions from Best Practices that are not relevant or may not be appropriate due to the company’s circumstances. An initial period

⁴⁸ See GO 112-F Sec 123(k) Gas Safety Plan.

(through the reporting of 2020 emissions and leaks) would be used to gather more information, test Best Practices and demonstrate effectiveness of these approaches. The proposed Compliance Plans must address each of the required Best Practices, but companies – depending on their size – may provide a justification for CPUC review explaining why any specific Best Practice in their plan is infeasible for the company during the compliance period, subject to approval by SED Staff.

In addition to the above provisions, basic elements of Staff's Revised Compliance Evaluation Plan include the following:⁴⁹

Compliance Plans:

- Written Compliance Plans identifying the policies, programs, procedures, instructions, documents, etc. used to comply with all of the approved 26 Best Practices in this proceeding. Exact wording shall be determined by the company. Compliance plans shall be signed by company officers certifying their company's compliance. CPUC shall have approval authority and authority to require modification before approval, in consultation with ARB.
- The Compliance Plan filing shall also incorporate many requirements of other Best Practices including policies and procedures, recordkeeping, training, experienced/trained personnel. In addition, other specific requirements in many leak detection, leak repair and leak prevention Best Practices are incorporated into the Compliance Plan filing.
- Compliance Plans shall be updated every two years to evaluate best practices based on progress and effectiveness of Companies'

⁴⁹ For a more complete list, see January 19, 2017 Revised Staff Proposal at "Staff Recommendations" at 7; "Significant Modifications" at 6; "Evaluation of Best Practices and R&D Pilots" at 13; and "BP 1 Compliance Plan" at 14. (Of the 26 Best Practices, BP 1 covers the basic elements of a Compliance Plan Framework.)

natural gas leakage abatement and methane emissions reductions.

- In specific Best Practices, Staff modified the language to allow companies to propose R&D and/or Pilot Programs.

Evaluation of Best Practices and R&D/Pilots

- 2020 Plan update shall include an evaluation of results, including costs and emissions reductions, of any R&D program and pilots that the utilities propose in their initial plans and employ in the initial compliance period.
- At the conclusion of the R&D or pilot programs, the utilities shall make recommendations for implementation/deployment, or for a revised Best Practice or an additional research plan based on results.
- SED shall convene a Technical Working Group to participate in a workshop or working group process similar to that used to develop the Best Practices to further refine the expected content and structure of the Compliance Plans, and a reasonable means by which the utilities can report on the outcomes of their test programs, recommend whether to continue to expand or curtail the effort, and for Staff to evaluate the outcomes.

Proposed Staff Classification Structure (*Ibid.* at 9)

- Utilities shall be organized into three classification tiers – “A,” “B,” and “C,” which are based on the utilities’ 2015 emission percentages.

The breakdown of Staff’s original proposal is as follows:

1. Class A: Utilities with 2015 baseline emissions equal or greater than 20% of the total aggregated annual emissions by all utilities (*see* Joint Staff report dated January 2017).
2. Class B: Utilities with 2015 baseline emissions between 1% and 20% of the total aggregated annual emissions.
3. Class C: Utilities with 2015 baseline emissions equal to or below 1% of the total aggregated annual emissions.

10.3. Parties' Comments

Based on responses to SED Staff's Revised Staff Proposal as discussed above, following is a summary of comments by major topic: General Compliance Plan Framework; Incorporation into Safety Plans; Enforcement Models, Integration into CPUC GOs and coordination with ARB and Local Air Districts; Classification of Utilities; Working Group Activities; and Timing of Deliverables.

General Compliance Plan Framework

PG&E, SoCalGas/SDG&E, Southwest Gas, ISPs, EDF, ORA agree with the compliance plan concept including implementation of "R&D" and "Pilots" as appropriate. According to PG&E, "Taken together, this framework and the Best Practices would balance the need for meaningful methane emission reductions with operational and technical feasibility and customer affordability." (PG&E February 10, 2017 Comments at 5.). PG&E emphasizes, "If the Commission determines an operator's plan is insufficient and additional measures should be implemented, for example requiring full-scale deployment of best practices an operator proposes to pilot, the Commission can require an operator to make this change as part of the approval process." "Moreover, nothing in SB 1371 mandates any one process or set of requirements or alters the normally wide discretion afforded to implementing agencies." (PG&E February 17, 2017 Comments at 2.) According to SoCalGas and SDG&E, "We believe this is a reasonable framework for a path forward." (SoCalGas/PG&E February 10, 2017 Comments at 8.) Similarly, Southwest Gas believes that SED Staff's Best Practices Proposal was well thought out and representative of the interests of various stakeholders. "The Company supports the use of Compliance Plans, and

the opportunity to work with SED on the development of Best Practice Portfolios.” (Southwest Gas February 19, 2017 Comments at 5.)

ISPs want credit for best practices they have already developed and for additional best practices that are appropriate for their facilities. Plans will likely include requests for exemptions for Best Practices that are not appropriate to apply to an ISP facility and are not cost effective. (ISPs February 10, 2017 Comments at 5.) The ISPs currently have no plans in place to propose R&D pilot programs, but may wish to do so as technology develops in advance of the timeframe in which ISPs would have to submit a Compliance Plan. (ISPs February 10, 2017 Comments at 6.)

EDF acknowledges that while compliance plans are an important regulatory tool, “they do not negate the need for the actual standards or Best Practices to be strong and enforceable.” (EDF February 10, 2017 Comments at 8.) EDF argues that there should be a public Commission process to evaluate the compliance plans, with opportunity for external comment. “Only with a formal public participation process can outside parties be assured the Commission will evaluate their input against that of utilities, especially as it relates to changes in technology or other best practices. This process does not have to be mentioned in the practice itself but should be stated in the decision.” (*Ibid.* at 8.) EDF also favors more transparency in the public posting of compliance plans on either the Commission website like the gas safety plans or on the websites of the individual regulated entities. “SB 1371 strives for more transparency with respect to leaks, emissions and leak reduction efforts, and posting of the reports would help satisfy public transparency requirements.” (*Ibid.* at 8-9.) In contrast, SDG&E and SoCalGas disagree with this recommendation. “The compliance plans are required to be approved by the Commission, in consultation with ARB.” They

further opine, “Allowing time for external parties to evaluate and comment on all compliance plans will only delay the implementation of plans and associated BPs.” (SoCalGas & SDG&E February 17, 2017 Comments at 4.)

ORA recommends that the utilities each file a short illustrative Compliance Plan prior to a Phase One Decision that can serve as an example to the Commission, ARB, and parties. (ORA February 10, 2017 Comments at Opening at 5.) SoCalGas and SDG&E and EDF do not support this recommendation because they think that it would delay the issuance of a Phase 1 decision. (SDG&E and SoCalGas February 17, 2017 Comments at 5, EDF February 17, 2017 Comments at 5.) EDF believes that “this practice may be most beneficial after the decision but before the final compliance plan framework is determined, if the entities draft the most controversial BPs (e.g. BP 15, BP 18, BP 20, and BP 21).” (EDF February 17, 2017 Comments at 5.)

Incorporation into Safety Plans

A common theme of parties’ comments is that if Best Practices have synergies with safety programs and policies, then they should be incorporated into those safety plans (e.g., dig-ins). ORA recommends that if a situation arises where the implementation of natural gas safety plans are not complementary, then the safety plans have primacy over efforts to reduce emissions levels. (ORA July 15, 2016 Comments at 4.) PG&E supports efforts to identify overlap between safety-related work and emission reduction efforts so that efficiencies may be realized. (PG&E July 15, 2016 Comments at 6.)

SoCalGas/SDG&E agree that Best Practices have synergies with safety programs and policies. For example, dig-in prevention is a paramount “safety” and “integrity” priority for the Joint Utilities. However, SoCalGas/SDG&E believe that optimizing gas saved from a blowdown activity during a

maintenance operation is not a focus of a safety program within the Gas Safety Plan and should be separately managed so as to not dilute the safety focus of the plan. (SoCalGas/SDG&E July 15, 2016 Comments at 12.) ISPs state that best practices, repair standards, and emission targets in any go forward compliance plan, can be incorporated as a separate section within the CPUC Gas Safety Plan of each entity. (ISPs July 15, 2016 Comments at 6.)

EDF agrees that emissions reduction should not take priority over safety work. At a minimum, it believes that safety plans should cross reference the compliance plans and targets for emission reductions. Incorporating required changes from an emission reduction perspective are likely to improve safety and integrity (e.g., leak repair timelines, analytical models, improved leak detection equipment, etc.) (EDF July 22, 2017 Reply Comments at 8). EDF believes that new practices can improve asset management decisions and allow for tracking of integrity management performance. (*Ibid.* at 8.)

Enforcement Models, Integration into CPUC GOs, and Coordination with ARB and Local Air Districts

Utilities support the Commission adopting an enforcement model that focuses on implementation of an operator's compliance plan which must be approved by the CPUC, in consultation with the ARB. PG&E states GO 112-F focuses on requirements to ensure pipeline safety and for this reason it does not appear to be an appropriate mechanism to implement a compliance and enforcement model to address emissions requirements. Joint Utilities recommend that after an initial grace period, all climate change requirements that are not safety driven procedures, should be incorporated into a separate GO for clarity. ORA recommends that the effort required to revise GOs or to establish new Orders would detract from the important work that should be

done to establish and implement best practices. CUE, with EDF's support, believes the Commission should amend GO 112-F to include all of the Best Practices in this proceeding. CUE believes that Section 143 contains definitions and requirements for leak surveys and leak grades, both of which should be changed through this proceeding. EDF claims a new GO could be problematic, as unlike GO-167 for electric generating facilities, emissions reductions cannot be completely separated from other parts of the system.

Utilities believe that if a Best Practice ends up as part of an ARB, DOGGR, or local district rule, then it is appropriate for those entities to have enforcement authority to inspect progress with that requirement. ISPs state that there must be consistency between CPUC, ARB, and DOGGR GHG emissions, regulations, targets, compliance, and enforcement.

ISPs believe that any system of financial penalties has to account for differences among regulated utilities. Any penalties should be calculated on an aggregated basis, rather than based on missing a target based on a single event in a given year.

Classification of Utilities

SoCalGas and SDG&E agree with SED Staff's recommendation to place SDG&E in a lesser category than the two largest investor owned utilities PG&E and SoCalGas. They argue that "SDG&E's emissions profile is significantly different from SoCalGas, so practices that apply to SoCalGas might not be applicable or effective at reducing emissions for SDG&E. For example, SDG&E does not have storage facilities, has fewer compression stations than SoCalGas, and does not have unprotected steel pipelines." (SoCalGas/SDG&E February 17, 2017 Comments at 4.) Given the operational differences between SoCalGas and

SDG&E, they contend “it makes sense for SDG&E to focus on a different set of Best Practices that would be more effective at reducing emissions.” (*Ibid.* at 4.)

However, EDF, CUE, and ORA recommend that SDG&E be included in the highest class of utilities: “Class A” or “Large.” EDF states, “The Commission cannot satisfy the statutory requirement to minimize emissions to the maximum extent feasible by excluding the third largest utility from the established best practices.” (EDF February 10, 2017 Comments at 16.) As for Southwest Gas, EDF only mentions that they are a leading utility because they have already implemented a three-year leak survey frequency. (Southwest Gas Comments February 17, 2017 Comments at 3.) EDF is also concerned with the purported purpose of the classes themselves. Supposedly, the classes provide “more flexibility” or “additional flexibility” but “CPUC staff have not provided any standards by which to judge their review.” (EDF February 10, 2017 Comments at 16.) EDF “suggests the CPUC wants authority for the sole purpose of approving exemptions, allowing regulated entities to avoid implementing the proven best practices if they deem them irrelevant.” (*Ibid.* at 16.) Both EDF and CUE believe that, if adopted, this undefined and arbitrary categorization for enforcement would amount to an abuse of discretion. (EDF February 10, 2017 Comments at 16, CUE February 17, 2017 Comments at 5.) EDF claims that what is being proposed is not what the Legislature had in mind.

ORA also disagrees with SED Staff’s new proposal to categorize gas utilities and storage providers into three different categories. The category in which a utility is placed would influence the amount of permissible leeway that utility would have in being allowed a waiver from implementing some best practices.

According to ORA, the categorization approach proposed by SED Staff would add “uncertainty” in the implementation of best practices. “Many of the best practices already permit utilities to file for an exemption from implementing those best practices. Additionally, the Commission will review the utilities’ Compliance Plans and can determine if any requested exemptions are reasonable” (ORA February 10, 2017 Comments at 4).

Additionally, ORA asserts, under SED Staff’s proposed categorization, the mitigation actions of some utilities may have adverse consequences on other utilities. Under SED Staff’s proposal, a utility that emits 0.9% of the total aggregated annual natural gas emissions would be considered a Class C utility. However, if there are sufficient emission reductions achieved by a Class A utility, then that utility would find itself reclassified as a Class B utility, and thus subject to more scrutiny, even if its volumetric emissions have also decreased, but by a lesser amount due to the size and current efficiency of that utility’s system. Similarly, if a Class B utility has a series of incidents or issues that result in significant emissions, but has still contributed less than 20% of the aggregated utility emissions, then the class designation does not inform the Commission as to whether the utility needs to follow additional Best Practices in order to rectify its emission issues. Therefore, ORA states, it is unclear what additional benefit this three-tier structure will add in providing guidance to the Commission’s review of the gas utilities’ Compliance Plans. (*Ibid.* at 5.)

ORA recommends that if the Commission deems it necessary to categorize the utilities for the purposes of aiding the review of their Compliance Plans, then the utilities should be classified as either “Large” or “Small.” The “Large” gas utilities would be PG&E, SoCalGas, and SDG&E. The “Small” utilities would be composed of the remaining regulated gas utilities. (*Ibid.* at 4-5.)

EDF agrees with ORA “that the class grouping of utilities would increase uncertainty and is unnecessary, given the exceptions within the individual practices.” (EDF February 17, 2017 Comments at 5.) It agrees that the proposed classification “will not inform the Commission of the improvements and incidents of the individual entities.” (*Ibid.* at 5.) If the Commission thinks that a classification is necessary, then it should put SDG&E in the class required to implement all of the practices. CUE asserts that “Class A would implement 25 of the 26 best practices but fail to state the compliance obligation for Class B or C.” (*Ibid.* at 5.) It is unclear what standard would be used for enforcement.

Technical Working Group

PG&E supports the continuation of the working group. PG&E recommends that the Phase 1 Decision instruct this working group to convene within 30 days of the Final Decisions to develop a scope and schedule for the working group. The working group should finalize all templates and methodologies for the SB 1371 Compliance Plans no later than six months before they are due so that parties have a reasonable opportunity to develop their respective Plans consistent with the working group guidance. (PG&E February 10, 2017 Comments at 6.)

Further, Southwest Gas agrees with SED Staff’s recommendations that a workshop or working group process should be established to refine the scope and detail of Compliance Plans and to develop a template and reporting structure for R&D and pilot programs. (Southwest Gas February 10, 2017 Comments at 5.) SoCalGas and SDG&E believe that clarification is needed on what should be included in the compliance plans, such as a cost-effectiveness methodology. (SoCalGas/SDG&E February 17, 2017 Comments at 5.)

Timing of Deliverables and Related Process

In addition, SoCalGas and SDG&E recommend establishing dates when the Compliance Plan templates will be finalized before the utilities are required to file their plans in March 2018, when the utilities can expect to receive individual approval of their Compliance Plan, and when the utilities can expect the evaluation of the outcome of future annual reports. (SoCalGas/SDG&E February 10, 2017 Comments at 2.) SoCalGas and SDG&E recommend that the Compliance Plan templates should be finalized at least six months prior to when the utilities file their first Compliance Plan in March 2018. Further, assuming the Compliance Plan templates will continue to go through a process of improvement over the coming years, it may be prudent to set additional dates for respondents to submit recommended changes to the various templates that will be developed. This date should be sometime between when Staff completes its evaluation of the Compliance Plan and annual reports and prior to Staff's March 31st deadline to publish the revised templates for the following year. (*Ibid.* at 8.)

10.4. Discussion

10.4.1. General Compliance Plan Framework

In this decision, we approve SED Staff's proposed General Compliance Plan Framework and all of its elements as stated above. However, in response to comments, we modify the classification of utilities structure, clarify requirements and eliminate some previous exemptions for Class B and C respondents, approve a slight modification to Order 112-F consistent with the directives of SB 1371, refer to the Commission's existing citation program as a vehicle to ensure compliance of this program, implement a more public process to review safety plans and pilots (e.g., public web posting of Compliance Plans and required

filing of Tier 3 ALs for capital projects that exceed a dollar cap), establish an annual timeline for the first biennial Compliance Plan and related process, and provide further detailed guidance as necessary.

The General Compliance Plan Framework shall be mandatory for all California natural gas utilities. This best practice requires utilities to submit written Compliance Plans with the CPUC identifying the policies, programs, procedures, instructions, documents, etc., to comply with the final decision in this proceeding in order to minimize natural gas leaks as a hazard and reduce methane emissions.

While every utility subject to this decision shall file a Compliance Plan, we recognize that companies vary substantially by business models, physical infrastructure, and operational and maintenance practices. Accordingly, similar to current requirements in the annual filing of Safety Plans, companies shall be required to include written documentation that a Company has complied, or has failed to comply with all of the Best Practices mandated by the Commission, and provide information on any additional voluntary measures proposed by each Company to abate natural gas leakage and reduce methane emissions.

We agree with EDF that there should be a public Commission process to evaluate the Compliance Plans. We believe it is important for SED Staff to convene a workshop after the Compliance Plans are submitted and before they are approved so that respondents may present their plans, provide insights to Commission staff that may aid staff's evaluation and allow the other parties to provide input on the Compliance Plans. This is especially important as technologies may change and best practices may be modified over time.

We also agree with EDF that more transparency aids rather than hinders the progress in this proceeding. For this reason, we direct respondents to

publicly post compliance plans on the Commission website like the gas safety plans and on the websites of the individual regulated entities.

10.4.2. Incorporation into Safety Plans

As SB 1371 directs, the Compliance Plans shall be submitted within the context of existing Gas Safety Plans. We agree that if a situation arises where the implementation of natural gas plans are not complementary, then the safety plans have priority over efforts to reduce emissions levels. In other words, in no situation should leak abatement and/or emissions reduction activities undermine safety or safety-related activities where the two are mutually exclusive. To the maximum extent possible, utilities should identify overlap between safety-related work and emission reduction efforts so that efficiencies may be realized. If there are no discernable synergies, then emissions reduction activities should be separately identified. We agree with SoCalGas/SDG&E that blowdown activities during a maintenance operation is not a focus of a safety program within the Gas Safety Plan and should be separately managed. In some cases, it may be difficult to distinguish between emission reduction and safety improvements (e.g., leak repair timelines, analytical models, improved leak detection equipment, etc.). In case of a conflict involving one or more improvements that cannot be identified as either an emission reduction or safety improvement, improvements that satisfy more than one attribute (e.g., safety, environmental, reliability) should be cross referenced and relative weights of these attributes assigned to determine which improvement prevails.

With the implementation of SB 1371, GO 112-F, Section 123- K Gas Safety Plan, shall be modified to read as follows:

1. Each Utility Operator must submit a Gas Safety Plan, as codified by Pub. Util. Code §§ 961 and 963, and 975, 977, and 978, and as ordered by the Commission in D.12-04-010 and this decision.

2. Each Utility Operator must make any modifications to its Gas Safety Plan identified by the Commission's Safety and Enforcement Division, or its successor.

Section 961(b)(4) referencing Section 1701.1, provides sufficient authority for the Commission to "review and accept, modify, or reject an updated plan at regular intervals thereafter." If issues arise in which proposed plans involve material disputed facts or expert witnesses, "the Commission, pursuant to Section 1701.1, shall determine whether a proceeding or proposed update to a plan requires a hearing."

10.4.3. Enforcement Models, Integration into CPUC GOs and Coordination with ARB and Local Air Districts

It is important that mechanisms are in place to ensure that the utilities submit complete and accurate annual reports and fully implement the requirements of their approved Compliance Plans. In this regard, we adopt an enforcement model that focuses on an operator's implementation of its annual compliance plan, which will be modified, if appropriate, and approved by the CPUC in consultation with the ARB. If gas operators violate the requirements of the Gas Safety Plan or newly revised GO 112-F, Section 123 K, which requires adherence to § 975, then gas operators are subject to staff issued citations through already established CPUC processes.⁵⁰ Further, the Commission retains the

⁵⁰ See Resolution ALJ-274 issued December 1, 2011: "Establishes Citation Procedures for the Enforcement of Safety Regulations by the Consumer Protection and Safety Division Staff [now known as "Safety and Enforcement Division" Staff] for Violations by Gas Corporations of General Order 112-E and Code of Federal Regulations," Title 49, Parts, 190, 191, 192, 193, and 199.

ability to pursue additional enforcement actions under other existing authorities regardless of any enforcement action, or lack of action, taken at the staff level.

GO 112-F currently focuses on requirements to ensure safety of transmission and distribution pipeline systems. However, during the 2020 compliance cycle, it makes sense to determine if GO 112-F should be modified to reflect changing annual report requirements (Section 123 “Annual Reports”); potential three-year leak survey cycle (Section 143.1 Distribution and Transmission Systems Leakage Surveys and Procedures); and Leak Classification and Action Criteria Grade Definition Priority of Leak Repair). During this evaluation phase, we concur with EDF and CUE that we could consider adding the 26 Best Practices to the existing GO. We agree with EDF that a new GO could be problematic, as unlike GO-167 for electric generating facilities, emissions reductions cannot be completely separated from other parts of the system and the synergies between safety and environmental goals need to be identified and harmonized.

Alternatively, after an initial grace period between 2018 and 2020, all climate change requirements that are not safety driven procedures, could be incorporated into a separate GO for clarity. We agree with ORA that completing the two OIR requirements of approving an annual report template and best practices protocol are the priority of this proceeding. Any premature efforts in this proceeding to revise GOs or to establish new Orders would have detracted from completing the important priorities in the first phase of this proceeding.

If a Best Practice ends up as part of a ARB, DOGGR, or local district rule, then those entities will have independent enforcement authority to inspect and enforce progress with that requirement. However, if those measures are part of

reaching a soft target established, the reductions still must be verified independently through this process.

While we strive for consistency between CPUC, ARB, and DOGGR's GHG emissions regulations, targets, compliance, and enforcement, we acknowledge that this may not be practically possible. In some cases, it may also not be appropriate, as one entity may choose to develop more stringent requirements than another. We highly recommend that Joint Staff look at the similarities and differences among and between the various regulations and suggest appropriate adjustments to the Best Practices through subsequent phases of this proceeding and the stakeholder process.

Instead of opening up a separate OIR to incorporate the natural gas leakage abatement and methane reduction rules and procedures in the existing GO 112-F or new GO, it is appropriate to revisit this issue in Phase Two of this proceeding.

10.4.4. Classification of Utilities

In response to comments, we concur that the class categorization determination and requirements can be clarified, have increased transparency, and even made more stringent, particularly for Class A and B utilities. First, the Commission believes that it is prudent to make public the actual 2015 annual emissions by utility in a combined format in the class categorization table. The emission profiles support a three-tiered class categorization methodology for methane emissions best practice requirements, especially when considering the need to implement cost-effective measures to meet the soft target goal of 40% reductions for this industry by 2030.

As for the differing comments on whether SDG&E, in particular, should or should not be a Class A utility, the simple fact is that SDG&E's methane

emissions are only an estimated 4% of 2015 total annual natural gas emissions compared to the combined 92% for PG&E and SoCal Gas' combined emissions profiles, not including the SoCalGas Aliso Canyon event emissions. SoCalGas and SDG&E alluded to this fact when supporting SDG&E to be in a lesser category since SDG&E's emissions profile is significantly different from SoCalGas'. Additionally, Southwest Gas has an estimated 3% emission rate; so to treat SDG&E and Southwest Gas as equal to the largest emitters (e.g., PG&E and SoCalGas) is unreasonable especially given that SB 1371 legislation requires the Commission to consider cost-effectiveness and affordability for ratepayers. Additional best practice requirements for Class A utilities compared to Class B utilities will necessarily add additional costs for the ratepayers of those utilities. Since the two largest emitters have more than 90% of the total annual emissions in this industry, the benefits of having these two utilities focus on all the best practice requirements is that the most emissions reductions can be expected from these two largest emission sources.

Additionally, we address ORA's concern that the mitigation actions of some utilities may have adverse consequences on other utilities if specific percentages of the total aggregated annual natural gas emissions are used as the threshold values for class categories. In order to address ORA's concern, we have revised the best practice class categorization methodology to use specific natural gas emissions amounts, rather than percentages, for the class category threshold values.

To also make the categorization system more stringent, we have calculated a lower specific threshold value of 500,000 Mscf which is approximately 5% of the total 2015 aggregated annual emissions (with Aliso Canyon). For comparison, SED Staff's January 2017 Staff proposal was for a threshold value of

approximately 1,320,000 Mscf between Class A and Class B categorizations which would have made it more unlikely that Class B utilities would be reclassified to Class A utilities.

With this revised methodology, if the two Class B utilities, SDG&E and Southwest Gas, increase their emissions by 200,000 to 300,000 Mscf (based on current emission factors), they would be reclassified to become Class A utilities, and subject to additional best practice requirements for a minimum of three years. At the same time, the lower threshold value for Class A utilities makes it less likely that the two large Class A utilities, PG&E and SoCalGas, will be able to be reclassified to Class B. To be reclassified as Class B, these Class A utilities would have to reduce their individual emissions by more than 80% from the 2015 baseline based on current emission factors. This classification is unlikely given the scale of reclassifications necessary.

In response to issues raised in the above discussion, including issues pertaining to using percentages, and based on non-confidential 2015 reported annual emissions data, the classification is revised as follows:

- Class A: Utilities with total annual emissions equal to or greater than 500,000 Mscf
- Class B: Utilities with total annual emissions between 50,000 and 500,000 Mscf
- Class C: Utilities with total annual emissions equal or below 50,000 Mscf.

The table below, Best Practice Class Categories by Company, lists the class categories that each company would be categorized in for this class categorization. As the emissions data is non-confidential and relevant to understanding, we also include actual 2015 annual emissions (Mscf) “without” SoCalGas Aliso Canyon event emissions and “with” Aliso Canyon along with

corresponding percentages of totals for both. Class categorizations are based upon 2015 emissions with Aliso Canyon although it should be noted that the categorizations would have been the same without the Aliso Canyon event, too. Class categorizations shall be based on the actual annual emissions based on the categories calculated from these 2015 baseline emission amounts.

R.15-01-008 / SB 1371					
Best Practice Class Categories by Company					
CPUC Regulated Natural Gas Utilities	2015 Annual Emissions (Mscf)		% Without	% With	BP Class
	Without Aliso Canyon	With Aliso Canyon	Aliso Canyon	Aliso Canyon	
Pacific Gas & Electric Co. (PG&E)	3,294,368.32	3,294,368.32	49.91%	32.20%	A
Southern California Gas Co. (SoCalGas)*	2,779,852.63	6,409,852.63	42.11%	62.65%	A
San Diego Gas & Electric Co. (SDG&E)	282,041.29	282,041.29	4.27%	2.76%	B
Southwest Gas Corp.	214,308.99	214,308.99	3.25%	2.09%	B
Wild Goose Storage, LLC	24,003.10	24,003.10	0.36%	0.23%	C
Lodi Gas Storage, LLC	1,638.00	1,638.00	0.02%	0.02%	C
Gill Ranch Storage, LLC	3,636.33	3,636.33	0.06%	0.04%	C
Central Valley Gas Storage, LLC	805.90	805.90	0.01%	0.01%	C
Alpine Natural Gas Operating Co. #1 LLC	5.60	5.60	0.0001%	0.0001%	C
West Coast Gas Co., Inc.	508.80	508.80	0.01%	0.005%	C
Total 2015 Emissions without & with Aliso Canyon event:	6,601,168.96	10,231,168.96			
*Unusual Large Leak (aka SoCalGas Aliso Canyon event):	3,630,000.00				
Best Practice Class Categorization and Basis (with Aliso Canyon):			Approximate Basis for Calculations:		
Class A - Equal to or greater than:	500,000	Mscf	Class A = or > ~ 5% of 2015 total		
Class B - In between:	50,000 and 500,000	Mscf	Class B in between 0.5% and 5%		
Class C - Equal to or below:	50,000	Mscf	Class C = or < 0.5% of 2015 total		

Above are the actual 2015 annual emissions amounts for each utility in the class category table, which have been previously thoroughly reviewed and analyzed by Joint Staff. These emission estimates show the order of magnitude difference between Class A and Class B utilities and again between Class B and the highest emitting Class C utility (Wild Goose Storage, LLC). Although EDF claimed that Southwest Gas is a “leading utility” in the industry due to its three-year leak survey cycle, it is noteworthy that Southwest Gas also has relatively high emissions for the number of customers and natural gas throughput on their California infrastructure. In researching Southwest Gas’

integrity management program, SED Staff advised the Commission that Southwest Gas three-year leak survey cycle and additional special leak surveys are required due to the specific safety risks that have been identified in Southwest Gas's system, mainly due to aging infrastructure. In comparison, SDG&E's 2015 estimated emissions were only approximately 68,000 Mscf more than Southwest Gas 2015 estimated emissions even though SDG&E's natural gas customers are much more numerous and its natural gas infrastructure is at least an order of magnitude larger by pipeline mileage. Hence, the Commission believes that a three-tiered Best Practice class categorization system is appropriate and meets legislative requirements to consider cost-effectiveness and affordability as more costly requirements for minimal emissions reductions will not have as high of benefits for those ratepayers.

On another note, as stated at the beginning of this discussion, we also concur with many parties that Class B and Class C utilities requirements should be clarified.

As for Class B utilities, we allow reasonable exemptions to be requested in utilities' Compliance Plan filing for the following Best Practices during the particular compliance period, assuming they apply to that company's infrastructure:

BP 14: Experienced, Trained Personnel requiring new job classifications

BP 17: Enhanced Methane Detection

BP 18: Stationary Methane Detectors

BP 19: Above Ground Leak Surveys

BP 20: Leak Quantification & Geographic Evaluation / Tracking

BP 22: Pipe Fitting Specifications

SED shall be required to review and either approve or disapprove any requests for exemptions in a reasonably timely manner. Utilities must justify why specific Best Practices should not apply to them, including but not limited to, demonstrating how these Best Practices will not achieve significant emissions reductions in light of data provided in their Annual Emissions Inventory Reports. These justifications shall be descriptive and reference data in each utility's Annual Emissions Inventory Reports related to the specific Best Practice being requested for exemption along with any other Best Practices or other measures that the utility is implementing or planning to implement to address that specific Best Practices' focus area (i.e., Training, Leak Detection, or Leak Prevention). If any utility in Class B has emissions that raise the utility to a Class A level, then that utility shall be required to submit a Class A Compliance Plan the next year a Compliance Plan is due for a Class A level utility. If, after this occurrence, that utility achieved emissions qualifying it to be a Class B level again two years in a row, then the following Compliance Plan to be filed would allow for Class B level compliance again.

For Class C utilities, due to these utilities' relatively minor emissions levels (i.e., total emissions are less than 1% of total aggregated emissions from all utilities), they shall be allowed to file requests for exemptions for the same Best Practices allowed for Class B utilities and in addition, these Class C utilities are allowed to file requests for exemptions for additional specified Best Practices assuming they apply to that company's infrastructure. The comprehensive set of Best Practices that Class C utilities are allowed to file requests for exemptions are:

BP 14: Experienced, Trained Personnel requiring new job classifications

BP 15: Gas Distribution Leak Surveys requiring maximum of 3 year survey cycles (if approved as is by the Commission)

BP 16: Special Leak Surveys

BP 17: Enhanced Methane Detection

BP 18: Stationary Methane Detectors

BP 19: Above Ground Leak Surveys

BP 20: Leak Quantification & Geographic Evaluation / Tracking

BP 21: "Find It / Fix It Policy"

BP 22: Pipe Fitting Specifications

BP 24: Dig-Ins / Public Education Program

BP 26: Dig-Ins / Repeat Offenders

Respondents shall provide succinct and descriptive justifications for why any requested Best Practices should be exempted. Class C utilities' are allowed to request exemptions from these Best Practices with the expectation that these utilities will continue to implement Best Practices, particularly leak prevention Best Practices. If any Class C utility has emissions that raise the utility to a Class B level, then that utility is required to submit a Class B Compliance Plan the next year a Compliance Plan is due for a Class B level utility. If after this occurrence, that utility achieved emissions qualifying it to be a Class C utility two years in a row, then a Compliance Plan shall be filed that would allow for Class C level compliance again.

These clarifications and further descriptions for the differences between Class A, Class B and Class C best practice categorizations, address many of the concerns raised by parties summarized earlier. Further, in order to further clarify the Commission's intent, the Best Practices themselves have been modified to remove any and all "request for exemption" type of language. This

will ensure that only utilities in specific classes are allowed to request exemption for allowable best practices.

10.4.5. Technical Working Group

The Technical Working Group that met during the first phase of this proceeding performed a valuable function towards completing deliverables and working through practical implementation issues associated with program development. We support the continuation of the working group and direct SED Staff to convene this working group within 30 days of this decision to discuss all templates and methodologies for the SB 1371 Compliance Plans that are due March 2018. Further, immediately following these technical working group discussions, SED Staff shall conduct a workshop to refine the scope and detail of Compliance Plans and to develop a template and reporting structure for R&D and pilot programs consistent with this decision.

Tasks that the Technical Working Group must address include:

- Content and template format of the Compliance Plan;
- Development of the pilot and R&D activities the gas corporations will include in their Compliance Plan; and
- Guidance on the cost and emissions reductions the utilities will propose to collect in 2018 and 2019 as proposed in the 2018 Compliance Plan.
- Direction regarding how the use of new scientific information shall be incorporated into ongoing reporting, best practices, and compliance plans.

In cooperation with SED Staff, the Technical Working Group will submit recommendations on the content and format of the Compliance Plan by October 31 and copy the service list.

We agree that Respondents should have guidance from SED as soon as possible before Compliance Plans are due so that they have a reasonable opportunity to develop their respective Compliance Plans consistent with the working group and workshop guidance. Due to the timing of the approval of this decision, six months' notice is not possible. So we recommend at least three months' notice assuming that the Technical Working Group convenes and related workshops occur in August and September 2017, respectively, as planned.

10.4.6. Timing of Deliverables and Related Process

In this section we discuss the process for developing compliance plans, the contents of the plans, and the processes for developing, submitting, and reviewing compliance plans. We give particular attention to the pilot and R&D proposals that may be submitted as part of the 2018 compliance plan and evaluated as part of the 2020 plans.

We concur with SoCalGas and SDG&E that it is prudent to establish dates when the Compliance Plan templates will be finalized before the utilities are required to file in March 2018, when the utilities can expect to receive individual approval of their Compliance Plans, and when the utilities can expect the evaluation of the outcome of future annual reports.

Accordingly we adopt the final schedule for Compliance Plan related schedules:

Within 45 days of this decision: SED shall convene a Technical Working Group and conduct a workshop to refine the scope and detail of the Compliance Plans.

By September 15, 2017: In cooperation with SED, the Technical Working Group shall submit recommendations on the content and the format of the Compliance Plan.

March 15, 2018: Respondents shall file Biennial Compliance Plans as part of its required annual Gas Safety Plans.

April 2018: SED Staff shall convene a public workshop to discuss Respondent's Compliance Plans.

June 2018: SED, in cooperation with ARB, shall complete a formal evaluation of Biennial Compliance Plans and provide a written response and direction for potential improvements.

30 Days After the Formal Evaluation and Before the Annual Data Request Issued on or before March 31: The assigned ALJ shall issue a ruling seeking comments regarding proposed changes to the Compliance Plan Template, Annual Report Template, and Pilot Requirements.

11. Cost Tracking and Cost Recovery

11.1. SB 1371 Requirements

SB 1371 also added § 977, which:

In order to achieve transparency and accountability for rate revenues and best value for ratepayers, and consistent with the commission's existing ratemaking procedures and authority to establish just and reasonable rates, the commission shall consider all of the following:

- (a) Providing for an adequate workforce to achieve the objectives of reducing hazards and emissions from leaks, including leak avoidance, reduction, and repair.
- (b) Providing revenues for all activities identified and required pursuant to § 975, including any adjustment of allowance for lost and unaccounted for gas related to actual leakage volumes.
- (c) Providing guidance for treatment of expenditures as being either an item of expense or a capital investment.
- (d) The impact on affordability of gas service for vulnerable customers as a result of the incremental costs of compliance with the adopted rules and procedures.

11.2. Parties' Comments

Southwest Gas, PG&E, SoCalGas/SDG&E, EDF and ORA agree that utilities should be allowed to recover best practices implementation costs in some form (Southwest Gas December 9, 2016 Comments at 3; PG&E December 9, 2016 Comments at 8-9; Sempra December 9, 2016 Comments at 15-18, EDF December 9, 2016 Comments at 21; and ORA December 9, 2016 Comments at 3-4.) whereas TURN rejects any form of cost recovery mechanism (TURN December 9, 2016 Comments at 2-3.) Among the rationales supporting a cost recovery mechanism, EDF points out, "The Commission must ensure that utilities have the means to achieve best practices outside of the general rate case, so that continual improvement can be made." (EDF December 9, 2016 Comments at 21.) In addition, PG&E stresses that prompt implementation of best practices to reduce methane emissions depends on the use of a cost recovery mechanism. (PG&E December 9 Comments at 8-9.)

Southwest Gas, PG&E, SoCalGas/SDG&E, and EDF encourage the use of two-way balancing account ("New Environmental Regulations Balancing Accounts" or "NERBA") for interim cost recovery. SoCalGas/SDG&E emphasizes that the current uncertainties around the implementation of SB 1371 new environmental requirements justifies the inclusion in the existing NERBA two-way balancing account to track and record any incremental costs not already authorized (SoCalGas/SDG&E December 9, 2016 Comments at 17.) However, TURN voiced the concern that "Unless actual incremental activities can be clearly and explicitly defined, it will be extremely difficult to segregate costs to prevent double recovery." (TURN December 9, 2016 Comments at 2-3.) PG&E explains that there are "potentially significant differences between PG&E's 2017 general rate cases GRC leak management forecast and new requirements ordered

by the Commission in Phase 1 of this proceeding” (PG&E December 9 Comments at 8-9). To support its position, PG&E provides two examples: “(1) the incremental cost of additional leak surveys and repairs of the gas distribution system as a result of shifting from leak surveys every four years to every three years is \$25.8 million (\$13.4M for expense and \$12.4M for capital); and (2) the incremental cost of implementing a special leak survey once a year on vintage plastic and steel pipe is \$53.3 million and the incremental cost of implementing a special leak survey four times a year on vintage plastic and steel pipe is \$213.1 million.” (*Ibid.*)

On the other hand, ORA favors a memorandum account for interim cost recovery because it provides “the opportunity for the reasonableness of cost associated with best practices to be transparently reviewed and approved before ratepayers pay for the costs” (ORA December 9, 2016 Comments at 3-4). TURN rejects the idea of a memorandum accounts for any new incremental costs (TURN December 9, 2016 Comments at 1 and 8). In support of this position, TURN argues, “While [SB 1371] has not yet been implemented [at the time gas utilities filed last rate cases], the utilities cannot argue that reduction in fugitive methane emissions is an entirely new and unanticipated expenditure” (*ibid.* at 2-3). SoCalGas/SDG&E disagrees because “the anticipated costs of SB 1371 cannot yet be precisely calculated, and the anticipated range of costs exceeds an amount that might be reasonably absorbed in routine operations.” (SoCalGas/SDG&E December 9, 2016 Comments at 18.) For the same reason, SoCalGas/SDG&E recalls that the Commission authorized the continuation of NERBA, including the costs for Leak Detection and Repair, in the 2016 GRC (*ibid.* at 16). In any event, TURN adds that “[...] the Commission is not obligated to

shield the utilities from absorbing all cost increases between rate cases” (*ibid.* at 2-3).

11.3. Discussion

As discussed above, PG&E, SoCalGas/SDG&E, and EDF support a two-way balancing account for best practices related expenditures. ORA supports a memorandum account and TURN recommends no account.

The primary purpose of balancing accounts is to ensure that a utility recovers its CPUC authorized revenue requirement from ratepayers for a given program or function, but no more or less.

To ensure the utility spends a certain authorized amount on specified activities, one- or two-way balancing accounts are established.

- A one-way cost balancing account ensures that if a utility spends less on a particular program than the amount authorized, it credits the remaining budget back to ratepayers.
- Two-way balancing accounts authorize a utility to collect more or less than the authorized revenue requirement for a given program depending on actual costs, and are intended to ensure that the utility does not make or lose money due to uncertainties in the scope of work.

The Commission typically reviews the entries and the net balance in a balancing account, and authorizes recovery from or refunds to ratepayers on an annual basis.

A memorandum account, on the other hand, allows the utility to book amounts for tracking purposes, in order to later ask the Commission for recovery.⁵¹

⁵¹ For example, the utilities currently recover the majority of their administrative costs through their periodic general rate cases or similar proceedings. For administrative costs that are incremental to those administrative costs previously approved through a utility’s general rate

Footnote continued on next page

It is reasonable to authorize the utilities to establish two-way balancing accounts to recover their best practices implementation costs. Within 30 days of this decision, each utility shall submit a Tier 1 AL to create these new Environmental Regulations Balancing Accounts, if they haven't already done so via another Commission order. (This can be implemented with a new sub-account in Sempra's already existing NERBA.) ORA is authorized to audit these accounts.

We find that it is not appropriate to include administrative costs of "unknown magnitude or nature" in these accounts; such costs should be subject to reasonableness review. Therefore within 30 days of this decision, each utility should file a Tier 1 AL to establish a new Natural Gas Leak Abatement Program memorandum account for incremental administrative costs.

For the balancing account, each utility is required to file a forecast for each of its Best Practices in its Compliance Plan and these should be broken by category (e.g., capital, administrative, O & M). Utilities should not begin to recover Natural Gas Leak Abatement costs in rates until the Commission has adopted cost forecasts and cost limits in response to Tier 3 ALs and approved Compliance Plans required by this decision. In the meantime, we permit utilities to record costs in the new NERBA, and to track and record administrative costs in new Natural Gas Leak Abatement Program Memorandum Accounts.

case or similar proceeding, e.g., due to a new regulatory program or policy adopted between rate case cycles, a memorandum account authorizes the utility to track the incremental expenses for future recovery. As part of the utility's request for recovery of administrative costs, the utility must demonstrate not only that the costs are reasonable, but also that the costs are incremental.

For pilot projects and R&D that may be permitted (BPs 16, 17, 18, 20, 21, 22, 23), we support a one-way balancing account that matches the expenditures with a spending cap/limit. If the expenditures do not meet the cap/limit, unspent funds are returned to ratepayers. If expenditures are greater than the cap/limit, the amount over the cap/limit cannot be recovered by the utility and is absorbed by shareholders. This mechanism is appropriate for tracking the costs of emerging technologies where costs may be uncertain yet likely expensive. Therefore, within 30 days of this decision, each utility should file a Tier 1 AL to establish a new Natural Gas Leak Abatement Program one-way balancing account for the costs of pilot projects and R&D activities associated with the program.

We support capping the incremental costs from pilot projects and R&D costs at specific dollar numbers for each utility, and allow a one-way balancing accounts up to a specified amount.

To establish an appropriate cap or cost limit, we find that it is reasonable to provide a Tier 3 AL review process for new Best Practice “emerging technology” projects such as special leak surveys⁵² as well as for incremental costs associated with other best practice implementation. Tier 3 ALs require a Commission resolution and affords sufficient due process for parties, while also providing a potentially shorter review time than an application.⁵³ In circumstances when it is important to act quickly regarding proposed new projects, and the project

⁵² See General Order 96-B, Energy Industry Rule. Section 5.3. This Section includes “a new product or service” as appropriate for a Tier 3 AL.

⁵³ Energy Division or the Commission may refer a Tier 3 AL to an ALJ for more detailed review and additional procedural steps if necessary.

and/or R&D is not controversial, Energy Division Staff, in consultation with SED Staff, can expeditiously prepare a resolution for Commission consideration.

The record is insufficient to establish a revenue forecast and/or cap for either the incremental costs associated with the best practices implementation or the pilot projects and R&D activities. With the understanding that parties will continue to refine the Compliance Plans after this decision is issued, we will allow the utilities appropriate time to provide a forecast of estimated costs and emissions reductions consistent with § 740.1. Therefore, on or prior to October 31, 2017, each PG&E, SoCalGas, SDG&E, and Southwest Gas shall each file a Tier 3 AL to provide the following to establish 2018 and 2019 ratemaking forecasts and caps for the Natural Gas Leak Abatement Program:

1. Identify the costs for incremental costs associated with each individual Best Practice, Pilot Projects and Research & Development (R&D), broken down by type of expenditure including capital, operations and maintenance, and administrative.
2. Provide the justifications consistent with the criteria to evaluate Pilot Projects and R&D in Pub. Util. Code § 740.1.
3. The proposed allocation methodology for amortization of the account and the corresponding Commission decision authorizing the allocation methodology.

The Director of Energy Division is authorized to recommend a process for reviewing cost forecasts, including the development of cost limits, and the methods for cost recovery in response to the Tier 3 Advice Letters ordered by this decision. This authorization applies to incremental costs related to Best Practices that are recorded in a two-way balancing account, and costs related to

Pilot Projects and Research and Development that are recorded in a one-way balancing account.

Respondents shall include the Commission authorized cost forecast and cost limit approved by Resolution in their gas transportation rates in connection with their consolidated rate update submittal for rates effective January 1, 2018. If the Resolution is not approved before respondents submit their consolidated rate update, then respondents shall submit a supplemental Advice Letter within 60 days of Resolution approval with the ratemaking limits grossed-up to recover 2018's authorized amount.

The ratemaking forecasts and caps shall apply until ratemaking amounts and treatment for the Natural Gas Leak Abatement Program for 2020 and beyond, including Best Practices, Pilot Projects and Research and Development, are reviewed and established in each utility's next general rate case or other gas ratemaking proceeding.

During a subsequent phase of this proceeding, it is prudent to consider whether the costs of specific Best Practices are significant enough that they should be moved from memorandum account treatment to the two-way balancing account for other BPs.

Further details regarding the above will be established in Phase Two of this decision.

12. Evolving Roles of ARB and CPUC

12.1. SB 1371 Requirements

According to SB 1371, the Public Utilities Code specifies that this proceeding is to be conducted "in consultation with the State Air Resources Board (ARB)." Pub. Util. Code § 975(d). Thus, the Commission will consult with ARB as it conducts the regulatory development process, including seeking ARB's

views on data submitted to the Commission in this proceeding, and ARB's views on potential regulatory designs. This consultation also includes developing and coordinating reporting and data-sharing duties for regulated entities as feasible, *see id.* § 975(e)(5)-(6). ARB Staff and the Commission will conduct these consultations under a non-disclosure agreement, but the results of the consultation, including (as appropriate) separate statements of ARB's views, will be presented in the Joint Staff reports shared for comment and further discussion with parties to this proceeding. The parties should also note that the statute preserves ARB's authority to develop its own regulations for GHG's, including for this sector. *See id.* § 975(h).

12.2. Scoping Memo Framework

As directed by the Scoping Memo, ARB took the lead role in quantifying and evaluating emissions, analyzing trends, and developing quantification protocols. As part of this role, ARB, in consultation with the CPUC, utilized its expertise in GHG emissions and:

- Compared the data collected under SB 1371 with the Mandatory Reporting Regulation;
- Analyzed incoming data to determine potential mitigation priorities based on emissions. For example, older pipelines of any material may have more leaks or pipelines of a certain material may have more leaks;
- Identified any remaining data gaps;
- Established procedures for the development and use of metrics to quantify emissions; and
- Reviewed and evaluated the operation, maintenance, repair, and replacement of natural gas pipeline facilities to determine if existing practices are effective in reducing methane leaks and where alternative practices maybe required.

To aid the above, the CPUC directed a robust stakeholder process to gain feedback from active parties on the annual reporting process, development of best practices and related compliance plan, etc., through technical group working group meetings, CPUC staff led workshops, teleconferences, and public comments. As stated in the procedural background of this proceeding, parties had more than ample opportunities to comment on the evolving annual reporting template and its many iterations, Annual Joint Staff Reports, as well as a final set of best practices that covered many functional areas. Through an iterative process, final deliverables were vastly improved from both a policy (i.e., development of mandatory standards) and implementation guidelines (i.e., focus on what is “maximum technologically feasible” and “cost-effective”) perspective. Joint Staff met regularly to ensure that scoping memo objectives were systematically achieved and to develop and implement a “startup” methane gas leak abatement program that could be sustained over time.

Beyond what is stated in the Scoping Memo, ARB played a strong collaborative role in the following activities:

- Developing EFs for annual reporting of methane leaks where “direct measurement” or “engineering estimates” are not readily available;
- Constructing confidentiality protocols that are on a par with other similar GHG decisions (e.g., D.14-12-037);
- Evaluation of alternative approaches to incorporate the “social cost of methane” which is a long term objective in this proceeding; and
- Evaluating the efficacy of long-term “hard” targets or short-term “soft” targets in light of recently enacted legislation (i.e., SB 1383).

12.3. Discussion

Given the importance of these reductions to achieving the state's climate goals, ARB will use and continue to monitor the emissions information over time to inform related climate change regulations, programs, and policies. ARB will also continue to implement new regulations that followed its independent rulemaking on methane emissions from upstream oil and gas production sources, including transmission compressors and underground storage.

ARB will continue to work with the Commission to determine the best management practices and other mitigation technologies for achieving GHG reductions. ARB will collaborate with the Commission and provide GHG expertise throughout the proceeding, including subsequent phases of the Best Practice proceeding and future rulemakings to meet the remaining requirements of SB 1371. The Commission will continue to fulfill its mandate to ensure its role to oversee costs associated with 26 Best Practices including pilots that test emerging leak detection and leak prevention technologies. ARB will be an advisor to the CPUC in the approval of respondent's biennial Compliance Plans. The two agencies will ensure, on ongoing bases, that both the public safety and the State's climate change goals will be achieved.

13. Phase Two of the Proceeding

The Scoping Memo planned a second phase of this proceeding to develop ratemaking guidelines and performance-based financial incentives associated with the Natural Gas Leak Abatement Program. However, we have learned in this first phase that additional attention is needed on data collection, the development of compliance plans, and we need to establish metrics for quantifying the costs and benefits of the best practices adopted herein. Most parties agree that these issues are a priority and reasonable next steps.

We set out the following activities for phase two of the proceeding.

- Continue the work of a technical working group and refine the annual reporting template including technical definitions as necessary;
- Develop Best Practice-related metrics to be reported in annual reports;
- Develop a 2018 Compliance Plan Framework consistent with directives of this decision;
- Develop a process and methodology for evaluating utilities' compliance with their approved compliance plans;
- Define a process for evaluating cost-effectiveness of Best Practices and future rules;
- Establish a process to gather and evaluate data on the cost of mitigation measures and the resulting emission reductions and pilot projects and R&D to support Best Practices;
- Provide guidance for collection of cost and emissions data for the 2018 and 2020 biennial compliance cycles.
- Provide further guidance regarding cost recovery and allocation through two-way and one-way balancing accounts and memorandum accounts.
- Provide further guidance regarding the interaction of SB 1371 Compliance Filings and utilities' future GRCs.
- "Harmonize" 26 mandatory Best Practices with other state and federal agency existing and emerging regulations (e.g., DOGGR, ARB, EPA) as necessary and appropriate.
- Consider incorporation of mandatory 26 Best Practices into existing CPUC GO 112-F, or separate order.
- Consider how the soft target could become a hard target for 2030 after the 2020 compliance plans are developed with additional cost information.

- Consider use of performance incentives and whether they should apply to system-wide metrics or for specific sources where emissions are known with greater certainty.
- Consider setting a cost effectiveness framework with or without use of a social cost of carbon and/or methane.
- Establish reporting requirements for the gas corporations' 2020 compliance plans.

CPUC and ARB will closely coordinate priorities, deliverables, and timeline for the second phase of this proceeding. The primary forums to resolve issues will continue to be technical working group activities, workshops, teleconferences, ongoing staff reports, and public comments. A second PHC for this proceeding will be scheduled and an amended scoping memo for Phase Two will be issued following Commission approval of this decision.

14. Categorization and Need for Hearing

The scoping memo confirmed that the Commission's preliminary categorization of R.15-01-008 as quasi-legislative and that hearings were not necessary. The Commission may re-evaluate the need for hearings in the second phase of this proceeding.

15. Comments on Proposed Decision

The proposed decision of Commissioner Rechtschaffen in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on June 5, 2017 by SoCalGas/SDG&E, PG&E, CUE, EDF, ISPs, and TURN; and reply comments were filed on June 12, 2017 by SoCalGas/SDG&E, PG&E, Southwest Gas, CUE, and EDF.

In response to parties' comments, the following changes have been made to the Ordering Paragraphs (OPs), Best Practices (BPs), and related text in the decision: (Note: Changes are noted in *italics*. All OP's relate to "cost recovery" with the exception of OP 5 and 6(e) below.) Throughout this decision edits were made to clarify the order, including addressing the following changes:

Ordering Paragraphs:

OP 5: Respondents shall eliminate their backlog of leaks within three years of the effective date of this decision, *unless the Commission's Safety and Enforcement Division grants an exemption* for cost prohibitive repairs included in best practice 21 "Find It/Fix It" and leaks under more stringent schedules according to General Order 112-F.

OP 6 (d): Within 45 days of this decision, the Commission's Safety and Enforcement Division (SED) *and Energy Division (ED)* shall convene a Technical Working Group and conduct a workshop to refine the scope of the Scope of the Compliance Plans *and Tier 3 Advice Letters pertaining to cost forecasts, tracking and recovery as detailed in this decision.*

OP 6 (e): *By September 15, 2017* [was October 31, 2017], and in cooperation with SED, the Technical Working Group shall submit recommendations on the content and the format of the Compliance Plan.

OP 8: Within 30 days of this decision, Pacific Gas and Electric Company Southern California Gas Company (*SoCalGas*), San Diego Gas & Electric Company (*SDG&E*), and Southwest Gas Corporation (*collectively "the utilities"*) shall each submit a Tier 1 Advice Letter to create a Memorandum Account for incremental *administrative costs associated with the* Natural Gas Leak Abatement Program expenditures.

OP 10: On or prior to October 31, 2017, Pacific Gas and Electric Company, Southern California Gas Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall each file a Tier 3 Advice Letter (AL) to provide the following *to establish 2018 and 2019 ratemaking forecasts and caps for the Natural Gas Leak Abatement Program: ...*

OP 10 (d) [now OP 11]: *The Director of Energy Division is authorized to recommend a process for reviewing cost forecasts, including the development of cost limits, and the methods for cost recovery in response to the Tier 3 Advice Letters ordered by this decision. This authorization applies to incremental costs related to Best Practices that are recorded in a two-way balancing account, and costs related to Pilot Projects and Research and Development that are recorded in one-way balancing account.*

Note: The following language has been eliminated: “In response to the Tier 3 ALs, Energy Division, with support from the Safety and Enforcement Division, shall prepare a Resolution that recommends a ratemaking cap for incremental costs for the Best Practices, Pilot Projects and R&D expenses and clarifies further direction about the process for approving additional projects.”

OP 12 [Added]: *The ratemaking forecasts and caps that the Commission approves in response to the Tier 3 Advice Letters shall apply until ratemaking amounts and treatment for the Natural Gas Leak Abatement Program for 2020 and beyond, including Best Practices, Pilot Projects and Research and Development, are reviewed and established in each utility’s next general rate case or other gas ratemaking proceeding.*

OP 11 [now OP 13]: Respondents shall not begin to recover Natural Gas Leak Abatement Program costs in rates until the Commission has adopted cost forecasts and cost limits in response to the Tier 3 Advice Letters and approved Compliance Plans required by this decision. *Respondents shall include the Commission authorized cost forecast and cost limit approved by Resolution in their gas*

transportation rates in connection with their consolidated rate update submittal for rates effective January 1, 2018. If the Resolution is not approved before respondents submit their consolidated rate update, then respondents shall submit a supplemental Advice Letter within 60 days of Resolution approval with the ratemaking limits grossed-up to recover 2018's authorized amount.

Best Practices:

BP 20 (Quantification and Geographic Tracking) has been split into two parts: Quantification (BP 20a) and Geographic Tracking (BP 20b). BP 20b has been modified to additionally apply to Class B utilities.

16. Assignment of Proceeding

Clifford Rechtschaffen is the assigned Commissioner and Colette E. Kersten is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The Commission's Natural Gas Leak Abatement Program is guided by SB 1371 (Leno, 2014) established Pub. Util. Code § 975, *et seq.*, which requires the Commission to adopt rules and procedures to minimize natural gas leaks from commission-regulated gas pipeline facilities and operations to the greatest extent practicable.
2. On January 22, 2015, the Commission opened R.15-01-008 to implement the provisions of SB 1371.
3. In SB 1371, the Legislature stated that reducing methane emissions by promptly and effectively repairing or replacing the pipes and associated infrastructure that is responsible for these leaks advances both policy goals of natural gas pipeline safety and integrity and reducing emissions of greenhouse gases.

4. There is growing awareness that climate change impacts have high social costs, including adverse impacts upon public health and the economy.

5. Pursuant to Pub. Util. Code § 975, the OIR requires gas corporations or Respondents to: 1) file an annual report about their natural gas leaks, and their leak management practices; and 2) to establish and require the use of Best Practices for leak surveys, patrols, leak survey technology, leak prevention, and leak reduction. SB 1371 directs the Commission, in consultation with ARB, to achieve these two complementary goals.

6. SB 1371 requires efforts to address “leaks,” as defined in Appendix A, to include “ungraded,” or “nongraded” leaks, as well as “vented emissions” which may occur during various operations and may release methane from components other than pipelines that are part of the gas system.

7. Parties had multiple opportunities to provide formal feedback on various iterations of the annual reporting template and proposed best practices to reduce methane emissions.

8. Joint Staff originally believed that the largest source of emissions was from unrepaired Grade 3 pipeline leaks deemed non-hazardous under PHMSA criteria.

9. The 2016 and 2017 Joint Staff Annual Reports indicate that although graded leaks are significant, the vented emissions (e.g., maintenance blowdowns) and ungraded leaks and associated emissions (e.g., meter set assemblies or essentially the riser connection to the meter) make up the largest subset of emissions reported.

10. The potential for mitigation of emissions from facilities and components becomes apparent because they comprise nearly two thirds of the sector emissions.

11. Based on the latest 2017 Joint Staff Annual Report, parties generally agree that the report provides a credible assessment of trends regarding the natural gas emissions from leaks and vented emissions in transmission, distribution and storage facilities in California.

12. More work needs to be done to better quantify leak volumes, validate and update EFs to better approximate category population emissions, and increase confidence in the methods that would ensure consistent and comprehensive reporting across the utilities.

13. The baseline emissions estimate based on 2015 data provides a starting point to measure future natural gas emission reductions.

14. Natural gas system operators include large and small gas utilities, and ISPs.

15. ISPs in total emit less than one-half of a percent (0.5%) of all reported gas utility methane emissions, according to reports submitted to CPUC in 2016.

16. ISPs vary in size, type of infrastructure assets, and deployment of emissions monitoring technology.

17. ISPs earn revenues from competitive market-based service contracts, not cost-of-service rates.

18. The Joint Staff Annual Reporting Framework has undergone significant changes through a robust stakeholder process and continually improved versions.

19. The Annual Spreadsheet Template that accompanies the Joint Staff Annual Reporting Framework continues to evolve.

20. Establishing a common database to track leaks and emissions is important but a lesser priority than developing annual reporting metrics for the best practices.

21. Pub. Util. Code § 975(e)(5) requires emissions quantification, in order to give gas system operators, the CPUC and the public “accurate information” about the number and severity of leaks and about the quantity of natural gas that is emitted into the atmosphere over time.

22. D.06-06-066 and D.16-08-024, the CPUC’s most recent confidentiality decision, require public reporting for activities within the Commission’s jurisdiction, with limited exceptions where keeping information confidential is in the public interest.

23. Site-specific GIS level data is not required to fulfill the reporting requirements adopted herein pursuant to Pub. Util. Code § 975, *et seq.*, as more general census tract or zip code locational information is sufficient.

24. There is no basis for withholding the names of dig-in repeat offenders from the public.

25. Certain utilities express security concerns regarding publication of MAOP and pipe diameter, if the information is released in association with the specific location of the pipeline or gas facility, but note that other utilities make this information public.

26. The confidentiality protocols adopted in D.06-06-066 and D.16-08-024, including the additional requirements adopted herein, provide an adequate framework for determining what type of information should be subject to confidential treatment.

27. ARB and CPUC, in cooperation with key stakeholders, have made significant strides toward fulfilling and indeed exceeding the minimum annual reporting requirements as specified in SB 1371.

28. Pub. Util. Code § 975, *et seq.*, directs the Commission to adopt rules and procedures that reduce natural gas pipeline emissions to the maximum extent

feasible and that provide for the maximum technologically feasible and cost-effective avoidance, reduction, and repair of leaks and leaking components, while taking into consideration the impact of affordability of gas service for vulnerable customers as a result of incremental costs of compliance with the adopted rules or procedures.

29. On September 8, 2016 the California State Legislature approved AB 197 (Garcia, Chapter 250, Statutes of 2016) directing ARB to consider the social costs of GHG emissions.

30. Costs and ratepayer affordability are important considerations in the development and refinement of best practices to reduce methane emissions.

31. Parties disagree on whether the Commission should adopt a cost-effectiveness methodology for operators to evaluate and prioritize best practices, or develop a broader cost-benefit analysis for the entire methane leak abatement program.

32. Establishing a comprehensive cost effectiveness or cost-benefit methodology would delay emissions reductions expected through the implementation of best practices adopted herein.

33. There is no convincing evidence that consideration of total program costs is possible to achieve in the short-term.

34. Given the numerous unknowns associated with this new program, there is not enough quantifiable information to evaluate the cost-effectiveness of the best practices adopted herein.

35. Costs for best practices related to policies and procedures, record keeping, training, and personnel matters comprise existing activities and thus should not require significant incremental expenditures.

36. “Maximum technologically feasible” technologies include commercial available technologies, as well as emerging technologies where research and development can occur.

37. The Revised Staff Proposal contained in the January 17, 2017 Assigned Commissioner’s Ruling serves as the basis for the 26 best practices for minimizing methane emissions adopted herein.

38. Pub. Util. Code § 975, *et seq.*, does not require a uniform set of mandatory best practices for the Commission-regulated gas utilities.

39. Respondent utilities vary substantially by size, business model, physical infrastructure, and O&M practices.

40. Collecting and utilizing natural gas emission data from the gas system is necessary to determine what, where, when and how to reduce leaks in the most cost-effective manner.

41. Once the current backlog of leaks has been repaired and ongoing repair of newly discovered leaks has become standard practice, any remaining backlog will consist only of leaks the Commission has determined cannot be repaired within reasonable conditions or costs.

42. Two 2016 legislative actions provide important context for our implementation of Pub. Util. Code § 975. SB 1383 directs ARB to implement a comprehensive short-lived climate pollutant strategy to achieve a reduction in the statewide emissions of methane by 40% below 2013 levels by 2030; SB 32 sets a statewide 2030 greenhouse gas reduction target of 40% below 1990 levels.

43. An interim or soft emissions reduction target can help ensure timely implementation of best practices; a hard target may be more appropriate once more comprehensive data collection is available.

44. SB 1383 is not formally part of this rulemaking, but a 40% target is an important consideration as it provides a basis to potentially set a hard target in the future.

45. Pub. Util. Code § 975(e)(5) allows the Commission to incorporate the best practices adopted herein into the safety plans required under Pub. Util. Code § 961 and the applicable orders adopted by the Commission.

46. Gas operators that violate the requirements of the Gas Safety Plan or newly revised GO 112-F, Section 123 K, which requires adherence to Pub. Util. Code § 975, are subject to SED issued citations through established Commission processes.

47. If a Best Practice provision ends up as part of an ARB, DOGGR, or local district rule, then those entities will have independent enforcement authority to inspect and enforce progress with that requirement, in addition to the Commission's enforcement authority for the Best Practice.

48. Assigning best practices across a three-tiered utility class categorization system is consistent with the requirements in Pub. Util. Code § 975, *et seq.*, to consider cost-effectiveness and affordability when implementing the Natural Gas Leak Abatement Program.

49. A General Compliance Plan Framework is an appropriate vehicle to ensure that Respondents comply with mandatory best practices pertaining to policies, programs, procedures, instructions, documents, etc., to minimize natural gas leaks as a hazard and reduce emissions.

50. Consistent with Commission GO 96 B guidelines, it is reasonable to provide a Tier 3 AL review process for new Best Practice emerging technology projects such as enhanced methane detection.

51. Balancing accounts are appropriate to track costs associated with new, incremental programs and regulatory policies that have been generally pre-authorized for recovery.

52. The Commission typically reviews the entries and the net balance in a balancing account, and authorizes recovery from or refunds to ratepayers on an annual basis.

53. Memorandum accounts are appropriate to track administrative expenses for the Natural Gas Leak Abatement Program because these costs are uncertain and should be subject to reasonableness review and/or audit.

54. One-way balancing accounts are an effective method to use for discrete programs such as the Natural Gas Leak Abatement Pilot Programs and R&D, when the Commission wishes to monitor expenses for a specific purpose and maintain cost control.

55. Additional information is needed to determine an appropriate annual cost ratemaking forecast and cap for incremental costs from the best practices implementation, Pilot Projects and R&D.

Conclusions of Law

1. Since Phase 1 of this proceeding does not involve any material disputed issues of fact, evidentiary hearings were not necessary for this decision.

2. As defined by R.15-01-008, the Natural Gas Leak Abatement Program must accomplish two primary objectives: 1) require utilities to file an annual report about their natural gas leaks, and their leak management practices, and 2) to establish and require the use of Best Practices for leak surveys, patrols, leak survey technology, leak prevention, and leak reduction.

3. The Commission's Natural Gas Leak Abatement Program must accomplish all six elements set forth in Pub. Util. Code § 975(e) and should meet four key principles developed among the stakeholders and described in Section 7.3.

4. Natural gas leak data should be subject to disclosure and confidentiality rules established in D.06-06-066 and its successor decision D.16-08-024.

5. The burden of proof is on the utilities to justify why specific data should be treated as confidential.

6. In keeping with statutory and regulatory principles, it is reasonable to require Respondents to continue to post public versions of their annual reports online, including all data and reporting templates that are not confidential.

7. For security purposes, it is reasonable to publicly report natural gas emission leak data aggregated by zip code or census tract rather than GIS coordinates and street addresses.

8. The identities of dig-in repeat offenders should be shared with local and state agencies and made publicly available.

9. It is reasonable that MAOP and pipe diameter in the annual reports should be publicly available on Respondents' websites.

10. Locational information protected under confidentiality rules should be available pursuant to non-disclosure agreement.

11. Applicability of best practices should take into account the different infrastructure, operational characteristics and emission levels of each Commission-regulated gas corporation and/or pipeline facility, including ISPs, as defined in Pub. Util. Code § 975, *et seq.*

12. All required best practices should be mandatory to achieve the objectives of Pub. Util. Code § 975, *et seq.*, and statewide GHG reduction goals.

13. Permissible exemptions from a mandatory best practice should not be “automatic;” the burden of proof that an exemption is reasonable should be the responsibility of the gas corporation or ISP.

14. Joint Staff, should be responsible for any ongoing enhancements to the annual spreadsheet template.

15. SED Staff should collaborate with ARB to update emissions factors (EF) as appropriate.

16. Until new EFs are adopted in final form, operators should continue to use EFs as directed by CPUC and ARB in annual reporting templates.

17. While ARB is ultimately responsible for the development of EFs, the Commission and ARB should collaborate to ensure that updated EFs are available for the annual reporting process.

18. Utilities should collect information that can be utilized in a risk-assessment based study to determine cost-effective leak surveys and included in the Annual Emissions Inventory Reports.

19. The main aim of Pub. Util. Code § 975, *et seq.*, is to reduce methane emissions from natural gas pipeline facilities, and we conclude that in determining rules, regulations and transportation rates for pipelines, we must consider the global warming impact of methane emissions alongside our duty to ensure safety, reliability, and just and reasonable rates.

20. It is reasonable to develop cost containment strategies through pilot projects, R&D, appropriate exemptions, and prudent cost recovery processes, subject to Commission review and approval.

21. The Natural Gas Leak Abatement Program comprised of the Annual Reporting Framework (Section 5.2), Key Principles (Section 7.3) and

Appendices A (Definitions), and B (Best Practices for Minimizing Methane Emissions) should be adopted and implemented as detailed in this decision.

22. Additional data to support BP 15-Gas Distribution Leak Surveys should be collected to determine appropriate frequency requirements for mandatory leak surveys at distribution mains and service pipelines.

23. Utilities should eliminate their backlog of leaks within three years of the effective date of this decision, unless the Commission's Safety and Enforcement Division grants an exemption for cost prohibitive repairs included in BP 21.

24. It is reasonable to adopt SED Staff's Proposed Compliance Plan Framework with modifications that adjust the classification of utilities structure, clarify requirements, eliminate some previous exemptions for Class B and C Respondents, approve a slight modification to Order 112-F consistent with the directives of SB 1371, and establish a process and timeline to implement Compliance Plans.

25. It is reasonable to support SED Staff's recommendation that the compliance plans should include information on how each gas corporation plans to achieve a 40% reduction below 2013 levels by 2030, what level of reduction would be necessary by 2020 to achieve the 2030 target, and how they plan to achieve the 2020 reduction level.

26. Consistent with Pub. Util. Code § 975 (f), the Commission should update GO-112 F (approved in D.15-06-044) that requires rules and procedures, including best practices and repair standards to be incorporated into the safety and the applicable general orders adopted by the Commission.

27. SB 1371 allows the Commission to consider cost-effectiveness when establishing Best Practices.

28. As a matter of Commission policy (§ 451), the Commission must be concerned about just and reasonable rates.

29. The Commission should adopt an enforcement program that focuses on a utility operator's timely and complete implementation of its Biennial Compliance Plan, which is subject to review and approval by the CPUC in consultation with the ARB.

30. The Commission provides SED sufficient delegated authority to review and accept, modify, or reject an Biennial Compliance Plan.

31. Compliance Plans should include sufficient information for the Commission, ARB, and stakeholders to fully evaluate a utility's Natural Gas Leak Abatement Program and any claim that an exemption to a mandatory best practice is reasonable.

32. Alternative measures, where allowed, should be based on practices equal to or superior to the currently known best practices and technologies.

33. The Commission has broad authority to implement regulations that go beyond those of companion agencies or our own existing applicable general orders.

34. The Commission retains the ability to pursue additional enforcement actions under existing authority regardless of any enforcement action or lack of action, taken at the staff level.

35. The utilities should use balancing accounts to track Natural Gas Leak Programs costs.

36. Within 30 days of this decision, PG&E, SoCalGas, SDG&E, and Southwest Gas each should submit a Tier 1 AL to create a Natural Gas Leak Abatement Program Balancing Account (NERBA) for incremental Natural Gas Leak Abatement Program expenditures, if they haven't already done so.

37. Each utility is required to file a forecast of incremental costs for each of its Best Practices, broken down by cost category (e.g., capital, administrative, and O&M), and the cost forecast should be included in its Compliance Plan.

38. Within 30 days of this decision, PG&E, SoCalGas, SDG&E, and Southwest Gas each should submit a Tier 1 AL to create a memorandum account for incremental administrative costs associated with the Natural Gas Leak Abatement Program.

39. Pub. Util. Code § 740.1 provides specific guidelines in evaluating research, development, and demonstration programs proposed by electrical and gas corporation.

40. It is reasonable to use the Tier 3 AL process when approving incremental costs associated with Best Practices, Pilot Projects and R& D expenses according to GO 96-B.

41. Within 30 days of this decision, PG&E, SoCalGas, SDG&E, and Southwest Gas each should file a Tier 1 AL to establish a new Natural Gas Leak Abatement Program one-way balancing account to track the costs of Pilot Projects and R&D.

42. In a Tier 3 AL, PG&E, SoCalGas, SDG&E, and Southwest Gas, should each provide annual forecasts of anticipated costs and emissions reductions, for years 2018 and 2019, consistent with Pub. Util. Code § 740.1, so that an appropriate revenue requirement cap on a forecast basis for balancing accounts can be devised.

43. By October 31, 2017, it is reasonable to request PG&E, SoCalGas, SDG&E, and Southwest Gas to each file a Tier 3 AL to establish 2018 and 2019 ratemaking forecasts and caps for the National Gas Leak Abatement Program.

44. It is reasonable that the Director of Energy Division should be authorized to recommend a process for reviewing cost forecasts, including the development

of cost limits, and the methods for cost recovery in response to Tier 3 Advice Letters ordered by this decision. This authorization applies to incremental costs related to Best Practices that are recorded in a two-way balancing account, and costs related to Pilot Projects and Research and Development that are recorded in a one-way balancing account.

45. It is reasonable that ratemaking forecasts and caps should apply until ratemaking amounts and treatment for the Natural Gas Leak Abatement Program for 2020 and beyond, including Best Practices, Pilot Projects, and Research and Development, are reviewed and established in each utility's next general rate case or other gas ratemaking proceeding.

46. Respondents should not begin to recover Natural Gas Leak Abatement Program costs in rates until the Commission has adopted cost forecasts and cost limits in response to the Tier 3 Advice Letters requested by this decision and Compliance Plans have been reviewed. Respondents should include the Commission authorized cost forecast and cost limit approved by Resolution in their gas transportation rates in connection with their consolidated rate update submittal for rates effective January 1, 2018. If the Resolution is not approved before utilities submit their consolidated rate updates, Respondents should submit a supplemental advice letter within 60 days of the Resolution approval with the ratemaking cap grossed-up to recover 2018's authorized amount.

47. SED, with support from Energy Division, should perform a comprehensive evaluation of the Natural Gas Leak Abatement Program in 2020.

48. Respondents named in this proceeding, including Alpine Natural Gas Operating Company No. 1 LLC; Pacific Gas and Electric Company; San Diego Gas & Electric Company; Southern California Gas Company; Southwest Gas Corporation; West Coast Gas Company; Central Valley Gas Storage, LLC; Gill

Ranch Storage, LLC; Lodi Gas Storage, LLC; and Wild Goose Storage Inc., should be required to comply with the Natural Gas Leak Abatement Program.

49. It is reasonable to continue to resolve remaining issues associated with implementation of this program in a subsequent phase of this proceeding.

50. SB 1371 preserves ARB's authority to develop its own regulations for GHGs. (§ 975(h)).

51. This decision should be effective immediately.

52. Given the vast scope of issues associated the Natural Gas Leak Abatement Program, the proceeding should remain open to address Phase Two issues as discussed in this decision.

O R D E R

IT IS ORDERED that:

1. The Natural Gas Leak Abatement Program Annual Reporting Framework contained in Section 5.2 and Appendix A (Definitions) of this decision is adopted consistent with the process detailed below:

The Commission's Safety and Enforcement Division (SED), in consultation with the Air Resources Board (ARB), shall direct the annual report process as follows:

- a) Prior to the issuance of the annual data requests, SED Staff shall host a workshop to discuss the updated format and to ensure consistency with data which are separately reported to ARB and the Pipeline and Hazardous Materials Safety Administration. If there are no changes to the format and no new data, the workshop may be deemed unnecessary and cancelled with notice;

- b) SED shall submit annual data requests to Respondents consistent with Public Utilities Code Section 975 (c) and SED advice by March 31 that covers the previous calendar year;
 - c) Respondents shall submit to SED and ARB Staff a response to the data request with populated excel spreadsheet templates via DVD by June 15;
 - d) Respondents shall submit responses through the “Supporting Documents” Feature on the Commission’s Electronic Filing System by June 15 of each year;
 - e) Respondents shall submit responses consistent with the Commission’s confidentiality rules and guidance in this decision;
 - f) Respondents shall post public versions of these reports on Respondents’ websites and shall include all templates and associated data that are not confidential according to this decision;
 - g) SED and ARB Staff (Joint Staff) shall post a draft annual Joint Staff Report on the Commission’s website by November 15 and the Administrative Law Judge shall solicit parties’ comments; and
 - h) Based on comments, Joint Staff shall post a final draft report highlighting corrections/enhancements by December 31 or as soon as practicable.
2. The Commission’s Safety and Enforcement Division, in collaboration with the Air Resources Board, shall be responsible for administering and enforcing the Annual Reporting Framework and providing ongoing enhancements to the Annual Spreadsheet Template.
3. The following data shall be added to future Annual Emissions Inventory Reports with the detailed reporting requirements:
- a) Mileage and characteristics of distribution mains (size, pipe material, operating pressure);

- b) Number of services surveyed and leak find rates as a function of line item cost differentiated by grade of leak;
- c) Nature and occurrence of leaks differentiated by type of distribution pipe;
- d) Factors impacting the grading characteristics of a leak including historical leak data and other risk-assessment based data; and
- e) Data that correlates leaks and methane emissions with location on mains versus service lines or with distribution pipeline characteristics (e.g., pipe material, size, pressure).

4. The Natural Gas Leak Abatement Program 26 Mandatory Best Practices (and associated Key Principles contained in Section 7.3) to minimize methane emissions attached as Appendix B to this decision is adopted.

5. Respondents shall eliminate their backlog of leaks within three years of the effective date of this decision, unless the Commission's Safety and Enforcement Division grants an exemption for cost prohibitive repairs included in BP 21 "Find It/Fix It" and leaks under more stringent schedules according to GO 112-F.

6. The Natural Gas Leak Abatement Program General Compliance Framework with modifications and/or clarifications is adopted:

- a) General Order 112-F, Section 123-K Gas Safety Plan, shall be modified to read as follows (insert shown by underlined text):
 - 1. Each Utility Operator shall submit a Gas Safety Plan, as codified by Pub. Util. Code §§ 961 and 963, and 975, 977, and 978, and as ordered by the Commission in Decision 12-04-010 and Decision [this decision number].
 - 2. Each Utility Operator must make any modifications to its Gas Safety Plan identified by the Commission's Safety and Enforcement Division, or its successor.
- b) The following classification "A," "B," and "C" structure for utilities are adopted to guide the applicability of best practices and use of Pilot Projects and Research and Development (R&D), and exemptions, subject to the Commission review and approval.

- Class A: Utilities with total annual methane emissions equal to or greater than 500,000 Mscf.
 - Class B: Utilities with total annual methane emissions between 50,000 and 500,000 Mscf
 - Class C: Utilities with total annual methane emissions equal or below 50,000 Mscf
- c) Biennial Compliance Plans shall include information on how each Respondent plans to achieve a 40% reduction of emissions below 2013 levels by 2030, what level of reduction would be achieved by 2020, and how they plan to achieve the 2020 reduction level. Further information shall be included in Compliance Plans as detailed in Section 10 of this decision.
- d) Within 30 days of this decision, the Commission's Safety and Enforcement Division (SED) and Energy Division (ED) shall convene a Technical Working Group and conduct a workshop to refine the scope and detail of the Compliance Plans and Tier 3 Advice Letters pertaining to forecasts, cost tracking and recovery as detailed in this decision.
- e) By September 15, 2017, and in cooperation with SED, the Technical Working Group shall submit recommendations on the content and the format of the Compliance Plan.
- f) Commencing March 15, 2018, Respondents shall submit Biennial Compliance Plans as part of its required annual Gas Safety Plans specified in Public Utilities Code Section 961(b)1.
- g) In April 2018, SED shall convene a public workshop to discuss Respondents' Compliance Plans.
- h) In June 2018, SED, in cooperation with the Air Resources Board, shall complete a formal evaluation of Compliance Plans and provide a written response and direction for improvements.
- i) Thirty days after this evaluation and before the annual data request issued on or before March 31, the Administrative Law Judge will issue a ruling seeking comments regarding any proposed changes to the Compliance Plan Template, Annual

Report Framework and Accompanying Spreadsheet Template, and Pilot Projects and R&D requirement.

7. Within 30 days of this decision, Pacific Gas and Electric Company, Southern California Gas Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall submit a Tier 1 Advice Letter to establish a New Environmental Regulatory Balancing Account (NERBA) for incremental Natural Gas Leak Abatement Program expenditures, which for Southern California Gas Company and San Diego Gas & Electric Company translates to a sub-account in their already existing NERBA.

8. Within 30 days of this decision, Pacific Gas and Electric Company, Southern California Gas Company (SoCalGas), San Diego Gas & Electric Company (SDG&E), and Southwest Gas Corporation (collectively “the utilities”) shall each submit a Tier 1 Advice Letter to create a Memorandum Account for incremental administrative costs associated with the Natural Gas Leak Abatement Program expenditures.

9. Within 30 days of this decision, Pacific Gas and Electric Company, Southern California Gas Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall submit a Tier 1 Advice Letter to create a new Natural Gas Leak Abatement Program one-way balancing account for the costs of Pilot Projects and Research and Development activities.

10. On or prior to October 31, 2017, Pacific Gas and Electric Company, Southern California Gas Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall each file a Tier 3 Advice Letter to provide the following to establish 2018 and 2019 ratemaking forecasts and caps for the Natural Gas Leak Abatement Program:

- a) Identify the costs for incremental costs associated with each individual Best Practice, Pilot Projects and Research &

Development (R&D), broken down by type of expenditure including capital, operations and maintenance, and administrative.

- b) Provide the justifications consistent with the criteria to evaluate Pilot Projects and R&D in Pub. Util. Code § 740.1.
- c) The proposed allocation methodology for amortization of the account and the corresponding Commission decision authorizing the allocation methodology.

11. The Director of Energy Division is authorized to recommend a process for reviewing cost forecasts, including the development of cost limits, and the methods for cost recovery in response to Tier 3 Advice Letters ordered by this decision. This authorization applies to incremental costs related to Best Practices that are recorded in a two-way balancing account, and costs related to Pilot Projects and Research and Development that are recorded in a one-way balancing account.

12. The ratemaking forecasts and caps that the Commission approves in response to the Tier 3 Advice Letters above shall apply until ratemaking amounts and treatment for the Natural Gas Leak Abatement Program for 2020 and beyond, including Best Practices, Pilot Projects and Research and Development, are reviewed and established in each utility's next general rate case or other gas ratemaking proceeding.

13. Respondents shall not begin to recover Natural Gas Leak Abatement Program costs in rates until the Commission has adopted cost forecasts and cost limits in response to the Tier 3 Advice Letters and approved Compliance Plans required by this decision. Respondents shall include the Commission authorized cost forecast and cost limit approved by Resolution in their gas transportation rates in connection with their consolidated rate update submittal for rates effective January 1, 2018. If the Resolution is not approved before Respondents

submit their consolidated rate update, Respondents shall submit a supplemental Advice Letter within 60 days of Resolution approval with the ratemaking grossed-up to recover 2018's authorized amount.

14. All Respondents named in this proceeding, including Alpine Natural Gas Operating Company No. 1 LLC; Pacific Gas and Electric Company; San Diego Gas & Electric Company; Southern California Gas Company; Southwest Gas Corporation; West Coast Gas Company; Central Valley Gas Storage, LLC; Gill Ranch Storage, LLC; Lodi Gas Storage, LLC; and Wild Goose Storage Inc., shall comply with the Natural Gas Leak Abatement Program.

15. The Commission's Safety and Enforcement Division, with support from Energy Division, shall conduct a comprehensive evaluation of the Natural Gas Leak Abatement Program by no later than 2020 and submit a report with recommendations to the Commission.

16. All motions not yet ruled on in this proceeding are hereby deemed denied.

17. Rulemaking 15-01-008 remains open.

This order is effective today.

Dated June 15, 2017, at Sacramento, California.

MICHAEL PICKER

President

CARLA J. PETERMAN

LIANE M. RANDOLPH

MARTHA GUZMAN ACEVES

CLIFFORD RECHTSCHAFFEN

Commissioners

Appendix A Definitions

Appendix A - Definitions

A. "Pipeline" means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies."¹

B. "Leak" is defined as unintentional escape of gas from the pipeline."²

SB 1371 uses the words "leaks and leaking components". Some examples of leaking components are defective or worn gaskets, seals, valve packing, relief valves, pumps, compressors, etc.

C. "Hazardous Leak" means gas leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous."³

D. "Graded Leaks" – Gas leaks which are hazardous, or which could potentially become hazardous as described below:

i. 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."⁴

ii. 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."⁵

¹ Refer to 49 CFR 192.3.

² Refer to instructions for completing PHMSA form F7100.1-1 (rev. 5-2015).

³ Refer to 49 CFR 192.1001 and instructions for completing PHMSA form F7100.1-1 (rev. 5-2015).

⁴ Refer to G.O. 112F for more information.

iii. 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.⁶

E "Non-Graded Leaks" or "Ungraded Leaks" – Utility company leak grading programs usually apply to leaks below ground level or near ground level. Consequently, it is possible to have hazardous and non-hazardous Non-Graded, or Ungraded Leaks above ground. In the annual report template appendices, all types of hazardous and non-hazardous leaks have been accounted for and are tracked. Refer to the Comment Box in the "Leak Grade" column of the appendices for the correct codes to use when reporting leaks.

F. "All Damages" is damage caused by external forces such as dig-ins, accidents and natural forces like settlement, land movement, floods or earthquakes.

G. "Vented Emissions" (or "Emissions" as used in this data request) are releases of gas to the atmosphere which occur during the course of operations or maintenance. Some examples are:

- i. Purging (a.k.a. "blowdown") gas prior to hydro-testing a line.
- ii. Releases of gas which are a design function of equipment such as gas emitting from relief valve vents or pneumatic equipment.
- iii. Releases of gas caused by operations, maintenance, testing, training, etc.

H. "System-Wide Leak and Emission Rate Data" - These data are requested in Appendix 8 of this data request. After the data are submitted by the utilities and Independent Storage Providers (ISPs), the CPUC and ARB will

⁵ Refer to G.O. 112F for more information.

⁶ Refer to G.O. 112F for more information.

analyze them to determine how best to develop System-Wide Leak and Emission Rates for the various types of facilities and systems.

I. "Unusual Large Leak"- Any event at a gas storage facility or gas transmission system that results in the uncontrollable release of natural gas to the atmosphere for more than 24 hours.

(End of Appendix A)

Appendix B
Best Practices for Natural Gas Leak Abatement Program

Summary of Best Practices for Natural Gas Leak Abatement Program (with Allowed Exemptions, Pilots/R&D & Utility Class Classifications)				
CATEGORY	BP #	TITLE	EXEMPTIONS?*	PILOTS/R&D ALLOWED?*
Policies and Procedures	1	Compliance Plan	No	No
Policies and Procedures	2	Methane GHG Policy	No	No
Policies and Procedures	3	Pressure Reduction Policy	No	No
Policies and Procedures	4	Project Scheduling Policy	No	No
Policies and Procedures	5	Methane Evacuation Procedure	No	No
Policies and Procedures	6	Methane Evacuation Work Order Policy	No	No
Policies and Procedures	7	Bundling Work Policy	No	No
Policies and Procedures	8	Company Emergency Procedures	No	No
Recordkeeping	9	Recordkeeping	No	No
Training	10	Minimize Uncontrolled Methane Emissions Training	No	No
Training	11	Minimize Methane Emissions Policies Training	No	No
Training	12	Knowledge Continuity Training Programs	No	No
Training	13	Performance Focused Training Programs	No	No
Experienced, Trained Personnel	14	Formal Job Classifications	B, C	No
Leak Detection	15	Gas Distribution Leak Surveys	C	No
Leak Detection	16	Special Leak Surveys	C	Yes
Leak Detection	17	Enhanced Methane Detection	B, C	Yes
Leak Detection	18	Stationary Methane Detectors	B, C	Yes
Leak Detection	19	Above Ground Leak Surveys	B, C	No
Leak Detection	20a	Quantification	B, C	Yes
	20b	Geographic Tracking	C	Yes
Leak Repair	21	"Find-It/Fix-It"	C	No
Leak Prevention	22	Pipe Fitting Specifications	B, C	Yes
Leak Prevention	23	Minimize Emissions from Operations, Maintenance and Other Activities	No	Yes
Leak Prevention	24	Dig-Ins / Public Education Program	C	No
Leak Prevention	25	Dig-Ins / Company Standby Monitors	No	No
Leak Prevention	26	Dig-Ins / Repeat Offenders	C	No
*See description of Utility Class Categories A, B, and C below. No exemptions = Mandatory. If Class B or C are listed, requests for exemptions are subject to Safety & Enforcement Division review and approval.				
** Pilots and/or R&D programs may be proposed, subject to Commission approval.				
<u>Utility Class Categories</u>				
Class A: Utilities with total annual methane emissions equal to or greater than 500,000 Mscf.				
Class B: Utilities with total annual methane emissions between 50,000 and 500,000 Mscf.				
Class C: Utilities with total annual methane emissions equal to or below 50,000 Mscf.				

Appendix B Best Practices for Natural Gas Leak Abatement Program

No.	Best Practices	Rationale
	Policies and Procedures (P&P)	
BP 1	<p><u>Compliance Plan</u> Written Compliance Plan identifying the policies, programs, procedures, instructions, documents, etc. used to comply with the Final Decision in this Proceeding (R.15-01-008). Exact wording TBD by the company and approved by the CPUC, in consultation with CARB.</p> <p>Compliance Plans shall be signed by company officers certifying their company's compliance. Compliance Plans shall include copies of all policies and procedures related to their Compliance Plans. Compliance Plans shall be filed biennially (i.e. every other year) to evaluate best practices based on progress and effectiveness of Companies' natural gas leakage abatement and minimization of methane emissions.</p>	<p>Each company is of a different size and has a different business model. Compliance Plans will require Companies to include those Best Practices (BPs) mandated by the Commission, noting applicable exemptions and alternatives, and any additional measures proposed by each Company to abate natural gas leakage and minimize methane emissions. However, companies must submit a Compliance Plan for approval by the CPUC, in consultation with CARB, to ensure that they are complying with the decisions of this proceeding and SB 1371. The Compliance Plan filing also incorporates many requirements for other BPs including policies and procedures, recordkeeping, training, experienced/trained personnel. In addition, other specific requirements in many leak detection, leak repair and leak prevention BPs are incorporated into the Compliance Plan filing.</p>
BP 2	<p><u>Methane GHG Policy</u> Written company policy stating that methane is a potent Green House Gas (GHG) whose emissions to the atmosphere must be minimized. Include reference to SB 1371 and SB 1383. Exact wording TBD by the</p>	<p>Written company policies, referencing both SB 1371 (2014, Leno) and SB 1383 (2016, Lara), are needed to guide company activities and ensure effective implementation to abate natural gas leakage and minimize methane emissions.</p>

No.	Best Practices	Rationale
	company and approved by the CPUC, in consultation with CARB, as part of Compliance Plan filing.	
BP 3	<u>Pressure Reduction Policy</u> Written company policy stating that pressure reduction to the lowest operationally feasible level in order to minimize methane emissions is required before non-emergency venting of high-pressure distribution (above 60 psig), transmission and underground storage infrastructure consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of Compliance Plan filing.	Written company policies are needed to require minimization of methane emissions from company activities (e.g. blowdowns, other operational emissions, etc.), and ensure effective implementation consistent with Operations & Maintenance (O&M) safety, system integrity and reliability requirements.
BP 4	<u>Project Scheduling Policy</u> Written company policy stating that any high pressure distribution (above 60 psig), transmission or underground storage infrastructure project that requires evacuating methane will build time into the project schedule to minimize methane emissions to the atmosphere consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Projected schedules of high pressure distribution (above 60 psig), transmission or underground storage infrastructure work, requiring methane evacuation, shall	Written company policies to schedule projects for high pressure distribution, transmission or underground storage infrastructure projects to minimize methane emissions are needed to guide company activities and ensure effective implementation consistent with O&M safety, system integrity and reliability requirements. This scheduling projects BP applies to non-emergency venting of high pressure distribution (above 60 psig), transmission or underground storage infrastructure requiring methane evacuation.

No.	Best Practices	Rationale
	also be submitted to facilitate audits, with line venting schedule updates TBD. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.	
BP 5	<u>Methane Evacuation Procedures</u> Written company procedures implementing the BPs approved for use to evacuate methane for non-emergency venting of high pressure distribution (above 60 psig), transmission or underground storage infrastructure and how to use them consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.	Written company procedures are needed to guide company activities for methane evacuation implementation and ensure effective implementation consistent with O&M safety, system integrity and reliability requirements. This methane evacuation implementation BP applies to non-emergency venting of high pressure distribution (above 60 psig), transmission or underground storage infrastructure requiring methane evacuation.
BP 6	<u>Methane Evacuation Work Orders Policy</u> Written company policy that requires that for any high pressure distribution (above 60 psig), transmission or underground storage infrastructure projects requiring evacuating methane, Work Planners shall clearly delineate, in procedural documents, such as work orders used in the field, the steps required to safely and efficiently reduce the pressure in the lines, prior to lines being vented, considering alternative potential	Written company policies are needed for methane evacuation work orders to guide company activities and ensure effective implementation consistent with O&M safety, system integrity and reliability requirements. This methane evacuation work orders BP applies to non-emergency venting of high pressure distribution (above 60 psig), transmission or underground storage infrastructure requiring methane evacuation.

No.	Best Practices	Rationale
	sources of supply to reliably serve customers. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.	
BP 7	<u>Bundling Work Policy</u> Written company policy requiring bundling of work, whenever practicable, to prevent multiple venting of the same piping consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Company policy shall define situations where work bundling is not practicable. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.	Written company policy is needed for bundling work to guide company construction and O&M activities for coordination of multiple venting of lines to minimize excess methane emissions consistent with O&M safety, system integrity and reliability requirements. This bundling work BP requires companies to define situations where work bundling is not practicable.
BP 8	<u>Company Emergency Procedures</u> Written company emergency procedures which describe the actions company staff will take to prevent, minimize and/or stop the uncontrolled release of methane from the gas system or storage facility consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.	Most natural gas companies have gas systems containing large volumes of methane. An uncontrolled release can negate the methane reductions of other utilities and increase GHG emissions. Written emergency company procedures are needed to guide company staff to prevent, minimize, and/or stop the uncontrolled release of methane and ensure effective implementation consistent with O&M safety, system integrity and reliability requirements.

No.	Best Practices	Rationale
	<u>Recordkeeping</u>	
BP 9	<u>Recordkeeping</u> Written Company Policy directing the gas business unit to maintain records of all SB 1371 Annual Emissions Inventory Report methane emissions and leaks, including the calculations, data and assumptions used to derive the volume of methane released. Records are to be maintained in accordance with G.O. 112 F and succeeding revisions, and 49 CFR 192. Currently, the record retention time in G.O. 112 F is at least 75 years for the transmission system. 49 CFR 192.1011 requires a record retention time of at least 10 years for the distribution system. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.	Accurate reporting of methane emissions and leaks, including estimation methodologies and assumptions, is critical for regulatory audits to ensure compliance. Written company policy is needed to ensure these records are maintained for all SB 1371 relevant actual measured emissions and leaks and estimated emissions and leaks including calculations, data and assumptions to derive the volume of methane released.
	<u>Training</u>	
BP 10	<u>Minimize Uncontrolled Natural Gas Emissions Training</u> Training to ensure that personnel know how to use company emergency procedures which describe the actions staff shall take to prevent, minimize and/or stop the uncontrolled release of natural gas from the gas system or storage facility. Training programs to be designed by the Company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing. If	Most natural gas companies have gas systems containing large volumes of methane. An uncontrolled release can negate the methane reductions of other utilities and increase GHG emissions. This training BP is needed to ensure personnel know how to use emergency procedures to prevent, minimize and/or stop the uncontrolled releases of methane. This training BP allows for companies to submit draft training programs along with a process to update the program once finalized to allow companies opportunities to

No.	Best Practices	Rationale
	integration of training and program development is required with the company's General Rate Case (GRC) and/or Collective Bargaining Unit (CBC) processes, then the company shall file a draft training program and plan with a process to update the program once finalized into its Compliance Plan.	integrate changes to their existing training and program development through their existing GRC and/or CBC processes.
BP 11	<u>Methane Emissions Minimization Policies Training</u> Ensure that training programs educate workers as to why it is necessary to minimize methane emissions and abate natural gas leaks. Training programs to be designed by the Company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing. If integration of training and program development is required with the company's GRC and/or CBC processes, then the company shall file a draft training program and plan with a process to update the program once finalized into its Compliance Plan.	Training programs are necessary to help employees understand why it is important to abate natural gas leaks and minimize methane emissions. If they understand the reasoning behind the goals, they are more likely to comply with the company's policies and procedures. This training BP is needed to ensure workers knows methane emissions reductions policies. This training BP allows for companies to submit draft training programs along with a process to update the program once finalized.
BP 12	<u>Knowledge Continuity Training Programs</u> Knowledge Continuity (Transfer) Training Programs to ensure knowledge continuity for new methane emissions reductions best practices as workers, including contractors, leave and new workers	New workers need to be trained in how to abate natural gas leakages and minimize methane emissions. Knowledge continuity (transfer) training programs are also needed to alleviate knowledge gaps and improve safety for new methane emissions minimization best practices. This

No.	Best Practices	Rationale
	<p>are hired. Knowledge continuity training programs to be designed by the Company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing. If integration of training and program development is required with the company's GRC and/or CBC processes, then the company shall file a draft training program and plan with a process to update the program once finalized into its Compliance Plan.</p>	<p>training BP allows for companies to submit draft training programs along with a process to update the program once finalized to allow companies opportunities to integrate changes to their existing training and program development through their existing GRC and/or CBC processes.</p>
BP 13	<p><u>Performance Focused Training Programs</u> Create and implement training programs to instruct workers, including contractors, on how to perform the BPs chosen, efficiently and safely. Training programs to be designed by the Company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing. If integration of training and program development is required with the company's GRC and/or CBC processes, then the company shall file a draft training program and plan with a process to update the program once finalized into its Compliance Plan.</p>	<p>Training programs are necessary to instruct workers, including contractors, on how to perform BPs, efficiently and safely. This training BP is needed to ensure companies instructs workers, including contractors, on how to perform BPs, efficiently and safely. This training BP allows for companies to submit draft training programs along with a process to update the program once finalized to allow companies opportunities to integrate changes to their existing training and program development through their existing GRC and/or CBC processes.</p>
	<u>Experienced, Trained Personnel</u>	

No.	Best Practices	Rationale
BP 14	<u>Formal Job Classifications</u> Create new formal job classifications for apprentices, journeyman, specialists, etc., where needed to address new methane emissions minimization and leak abatement best practices, and filed as part of the Compliance Plan filing, to be approved by the CPUC, in consultation with CARB.	According to the Unions, there is a significant need for experienced, qualified people working in the field, and also for participation in the evaluation of existing practices and development of better (best) practices. Experienced gas system workers have first-hand knowledge of how system equipment operates, what the O&M problems are and how to fix them resulting in less methane leaks. If this is accurate, then methane leaks and emissions are not entirely infrastructure issues. Experienced workers are critical to help train, improve procedures, maintain and operate equipment and to address new methane emissions reduction and leak abatement best practices.
	<u>Leak Detection</u>	
BP 15	<u>Gas Distribution Leak Surveys</u> Utilities should conduct leak surveys of the gas distribution system every 3 years, not to exceed 39 months, in areas where G.O. 112-F, or its successors, requires surveying every 5 years. In lieu of a system-wide three-year leak survey cycle, utilities may propose and justify in their Compliance Plan filings, subject to Commission approval, a risk-assessment based, more cost-effective methodology for conducting gas distribution pipeline leak surveys at a less frequent interval. However, utilities shall	This leak detection BP recommends leak survey intervals of 3 years for all distribution pipelines formerly under the five-year leak survey requirement, unless the utility proposes and gets approved more effective leak survey cycles at a less frequent interval using a risk assessment approach. Different leak survey cycles may be appropriate for various districts or areas of a utilities' distribution system based on risk considerations of leak history, pipe material and age, soil conditions, etc.

No.	Best Practices	Rationale
	always meet the minimum requirements of G.O. 112-F, and its successors.	
BP 16	<p><u>Special Leak Surveys</u></p> <p>Utilities shall conduct special leak surveys, possibly at a more frequent interval than required by G.O. 112-F (or its successors) or BP 15, for specific areas of their transmission and distribution pipeline systems with known risks for natural gas leakage. Special leak surveys may focus on specific pipeline materials known to be susceptible to leaks or other known pipeline integrity risks, such as geological conditions. Special leak surveys shall be coordinated with transmission and distribution integrity management programs (TIMP/DIMP) and other utility safety programs. Utilities shall file in their Compliance Plan proposed special leak surveys for known risks and proposed methodologies for identifying additional special leak surveys based on risk assessments (including predictive and/or historical trends analysis). As surveys are conducted over time, utilities shall report as part of their Compliance Plans, details about leakage trends. Predictive analysis may be defined differently for differing companies based on company size and trends.</p>	<p>This leak detection BP requires utilities to conduct special leak surveys, possibly more frequently than G.O. 112-F or BP # 15, in coordination with their integrity management and other utility safety programs. Also, this BP states that the use of special leak surveys (for the purpose of SB 1371 compliance) shall be predicated on risk assessments, including predictive and historical trends analysis, if possible. This BP also allows for predictive analysis to be defined differently for differing companies based on company size and trends.</p>

No.	Best Practices	Rationale
BP 17	<u>Enhanced Methane Detection</u> Utilities shall utilize enhanced methane detection practices (e.g. mobile methane detection and/or aerial leak detection) including gas speciation technologies.	This leak detection BP requires utilities to use enhanced methane detection practices including enhanced gas speciation technologies. This BP allows utilities to propose specific technologies that are most suitable for their gas systems and geographical areas.
BP 18	<u>Stationary Methane Detectors</u> Utilities shall utilize Stationary Methane Detectors for early detection of leaks. Locations include: Compressor Stations, Terminals, Gas Storage Facilities, City Gates, and Metering & Regulating (M&R) Stations (M&R above ground and pressures above 300 psig only). Methane detector technology should be capable of transferring leak data to a central database, if appropriate for location.	This leak detection BP requires utilities to utilize Stationary Methane Detectors for early detection of leaks. This BP applies to locations including compressor stations, terminals, gas storage facilities, City Gates and Metering & Regulating (M&R) Stations (M&R above ground and pressures above 300 psig only). This BP recommends that methane detector technology is capable of transferring leak data to a central database, if appropriate for location.
BP 19	<u>Above Ground Leak Surveys</u> Utilities shall conduct frequent leak surveys and data collection at above ground transmission and high pressure distribution (above 60 psig) facilities including Compressor Stations, Gas Storage Facilities, City Gates, and Metering & Regulating (M&R) Stations (M&R above ground and pressures above 300 psig only). At a minimum, above ground leak surveys and data collection must be conducted on an annual basis for compressor stations and gas storage facilities.	This leak detection BP requires utilities to conduct frequent leak surveys and data collection at above ground transmission and high pressure distribution (above 60 psig) facilities including Compressor Stations, Gas Storage Facilities, City Gates, and Metering & Regulating (M&R) Stations (M&R above ground and pressures above 300 psig only). This BP also requires a minimum of annual surveys to be conducted for compressor stations and gas storage facilities.

No.	Best Practices	Rationale
BP 20a	<p><u>Quantification & Geographic Tracking</u></p> <p>Utilities shall develop methodologies for improved quantification and geographic evaluation and tracking of leaks from the gas systems. Utilities shall file in their Compliance Plan how they propose to address quantification. Utilities shall work together, with CPUC and ARB staff, to come to agreement on a similar methodology to improve emissions quantification of leaks to assist demonstration of actual emissions reductions.</p>	<p>This leak detection BP requires utilities to develop methodologies for improved quantification of leaks. This BP also requires utilities to work together, with CPUC and ARB staff, to come to agreement on a similar methodology to improve emissions quantification of leaks to assist demonstration of actual emissions reductions. Improved quantification technologies are very much needed in the industry. Quantifying the amount of natural gas emitted from a leak is dependent on equipment sensitivities and the ability to utilize equipment successfully to measure leakage. Therefore, it is critical to improve accurate emissions inventory data as lessons learned from reviewing Annual Emissions Inventory Report data is that much of the inventory is based on estimations.</p>
BP 20b	<p><u>Geographic Tracking</u></p> <p>Utilities shall develop methodologies for improved geographic tracking and evaluation of leaks from the gas systems. Utilities shall work together, with CPUC and ARB staff, to come to agreement on a similar methodology to improve geographic evaluation and tracking of leaks to assist demonstrations of actual emissions reductions. Leak detection technology should be capable of transferring leak data to a central database in order to provide data for leak maps. Geographic leak maps shall be publicly available with leaks</p>	<p>This BP also requires utilities to work together, with CPUC and ARB staff, to come to agreement on a similar methodology to improve geographic tracking and evaluation of leaks to assist demonstrations of actual emissions reductions. This BP also recommends that leak detector technologies are capable of transferring leak data to a central database in order to provide data for leak maps.</p>

No.	Best Practices	Rationale
	displayed by zip code or census tract.	
	Leak Repairs	
BP 21	<u>“Find It/Fix It”</u> Utilities shall repair leaks as soon as reasonably possible after discovery, but in no event, more than three (3) years after discovery. Utilities may make reasonable exceptions for leaks that are costly to repair relative to the estimated size of the leak.	As the only leak repair BP, this “find-it/fix-it” BP applies to all leaks. This BP requires utilities to repair all leaks within a maximum of three years of discovery, allowing for reasonable exceptions. In the short-term, utilities are also required separately to eliminate their backlog of leaks unless leak repairs are cost prohibitive.
	Leak Prevention	
BP 22	<u>Pipe Fitting Specifications</u> Companies shall review and revise pipe fitting specifications, as necessary, to ensure tighter tolerance/better quality pipe threads. Utilities are required to review any available data on its threaded fittings, and if necessary, propose a fitting replacement program for threaded connections with significant leaks or comprehensive procedures for leak repairs and meter set assembly installations and repairs as part of their Compliance Plans. A fitting replacement program should consider components such as pressure control fittings, service tees, and valves metrics, among other things.	This leak prevention BP addresses the very large number of threaded fittings and their known propensity to develop leaks. This BP requires companies to review and revise pipe fitting specifications and any available data on utilities’ threaded fittings, as necessary. This BP requires utilities to review their own pipe fittings specifications along with available data and if necessary, propose a fitting replacement program as part of their Compliance Plan. For example, Aeronautical National Pipe Taper (ANPT) threads (ANSI SAE AS71051) may be less leak-prone than National Pipe Taper (NPT) pipe threads (ANSI/ASME B1.20.1) since the former has 2 threads and the latter has 3 threads. However, other types of threads or connections may prove better.
BP 23	<u>Minimize Emissions from Operations, Maintenance and Other Activities</u> Utilities shall minimize emissions	Most natural gas companies have gas systems containing large volumes of methane. Large amounts of fugitive and vented emissions from operations,

No.	Best Practices	Rationale
	<p>from operations, maintenance and other activities, such as new construction or replacement, in the gas distribution and transmission systems and storage facilities. Utilities shall replace high-bleed pneumatic devices with technology that does not vent gas (i.e. no-bleed) or vents significantly less natural gas (i.e. low-bleed) devices. Utilities shall also reduce emissions from blowdowns, as much as operationally feasible.</p>	<p>maintenance and other activities, along with unforeseen catastrophic releases, can negate the methane reductions by other measures and significantly increase GHG emissions. This leak prevention BP focuses on minimizing fugitive and vented methane emissions including those from catastrophic releases, high-bleed pneumatics and blowdowns. This BP requires replacement of high-bleed pneumatic devices and also requires reduction of blowdown emissions, as much as operationally feasible.</p>
BP 24	<p><u>Dig-Ins / Public Education Program</u> Dig-Ins – Expand existing public education program to alert the public and third-party excavation contractors to the Call Before You Dig – 811 program. In addition, utilities must provide procedures for excavation contractors to follow when excavating to prevent damaging or rupturing a gas line.</p>	<p>Dig-Ins are a major cause of gas line ruptures. The utilities are already required to implement Dig-In public awareness programs. This leak prevention BP requires utilities to expand their existing public education programs and to provide procedures for excavation contractors to follow when excavating.</p>
BP 25	<p><u>Dig-Ins / Company Standby Monitors</u> Dig-Ins – Utilities must provide company monitors to witness all excavations near gas transmission lines to ensure that contractors are following utility procedures to properly excavate and backfill around transmission lines.</p>	<p>Dig-Ins are a major cause of gas line ruptures. This leak prevention BP is necessary to ensure contractors follow utility excavation and backfill procedures around transmission lines in order to try to prevent damage to a transmission line. (It is possible to nick or damage a transmission line which can be a root cause for a rupture years later.)</p>
BP 26	<p><u>Dig-Ins / Repeat Offenders</u></p>	<p>This leak prevention BP requires</p>

No.	Best Practices	Rationale
	<p>Utilities shall document procedures to address Repeat Offenders such as providing post-damage safe excavation training and on-site spot visits. Utilities shall keep track and report multiple incidents, within a 5-year period, of dig-ins from the same party in their Annual Emissions Inventory Reports. These incidents and leaks shall be recorded as required in the recordkeeping best practice. In addition, the utility should report egregious offenders to appropriate enforcement agencies including the California Contractor's State License Board. The Board has the authority to investigate and punish dishonest or negligent contractors. Punishment can include suspension of their contractor's license.</p>	<p>utilities to document procedures to address Repeat Offenders and to track and report multiple incidents in their Annual Emissions Inventory Reports. This BP recommends utilities report egregious offenders to appropriate enforcement agencies. This BP requires these incidents and leaks to be recorded under the Recordkeeping BP.</p>

(End of Appendix B)