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Joe Fischer
Project Lead, Oil & Gas Regulation
California Air Resources Board
1001 I Street – P.O. Box 2815
Sacramento, CA 95812

Re: SoCalGas and SDG&E Comments on Proposed Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities

Dear Mr. Fischer:

Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) appreciate the opportunity to submit these comments on the California Air Resources Board's (ARB) latest version of its Proposed Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, released May 31, 2016 (Proposed Regulation). SoCalGas and SDG&E strongly support ARB's objective to establish a comprehensive program of regulatory and market mechanisms to achieve real, cost-effective, and quantifiable reductions of greenhouse gases (GHG). The Proposed Regulation reflects many months of careful analysis by ARB staff and incorporates input from numerous stakeholders and experts in order to achieve this objective. SoCalGas and SDG&E commend ARB and its staff for these efforts and appreciate this opportunity to submit further comments. In the comments below, SoCalGas and SDG&E offer suggestions for how the Proposed Regulation can be further refined to support the goal of achieving real, cost-effective and quantifiable GHG reductions.

First, SoCalGas and SDG&E urge ARB to delay implementation of the storage well monitoring requirements to allow for greater stakeholder and expert input into the cost effectiveness and feasibility of options under consideration. This will help ensure that the Proposed Regulation adopts feasible and cost-effective measures to further ARB's objectives. Second, SoCalGas and SDG&E seek a revision to the Proposed Regulation to authorize leak detection and repair surveys to occur on an annual, rather than a quarterly basis. Similarly, this modification will further ARB's objective to achieve feasible and cost-effective measures to reduce GHG emissions. Third, SoCalGas and SDG&E encourage ARB to consider potentially conflicting or overlapping regulatory requirements in adopting the Proposed Regulation and implementation timelines. This will help regulated entities achieve compliance in a cost-effective manner and avoid potential regulatory conflict and uncertainty. Fourth, the Proposed Regulation enforcement provisions should be modified to achieve regulatory objectives and incentivize

GHG reductions. Fifth, the Proposed Regulation should adopt a 100-year time horizon to remain consistent with other regulations and avoid disrupting carbon credit markets.

## I. ADOPTION OF STORAGE WELL MONITORING REQUIREMENTS SHOULD BE DELAYED TO ALLOW FOR GREATER STAKEHOLDER AND EXPERT INPUT

In the Appendix B Economic Analysis of the Proposed Regulation, ARB indicates that there are *zero* emission reductions and gas savings associated with the Storage Facility Monitoring Plan. Given the lack of any emissions reduction benefits attributed to the Storage Facility Monitoring Plan and the high costs for preparing and implementing such a plan, it does not appear that this element in the Proposed Regulation furthers ARB's objective to establish regulatory mechanisms to achieve real, cost-effective, and quantifiable reductions of greenhouse gas emissions. For the following reasons, SoCalGas and SDG&E recommend that ARB remove the Storage Facility Monitoring Requirements from the Proposed Regulation, or if not removed, delay the adoption of these rules to provide stakeholders and experts time to provide input—particularly with respect to costs and technical feasibility.

First, there is a significant risk that this Proposed Regulation could conflict with regulations under consideration by the Division of Oil, Gas and Geothermal Resources (DOGGR), the principle state agency charged with regulating the drilling, operation, maintenance and abandonment of oil and gas wells.

Second, as explained in greater detail in Attachment A, the Economic Analysis significantly underestimates the costs of implementing the Proposed Rule storage facility monitoring provisions and the technology to conduct continuous monitoring, as envisioned by ARB, is not yet proven.

Third, unlike other provisions of the Proposed Regulation that have undergone two years of careful analysis and reflective input from stakeholders and experts, the Storage Monitoring requirements did not undergo a public process before submittal to the ARB Board.

## II. LEAK DETECTION AND REPAIR REQUIREMENTS SHOULD BE MODIFIED TO PROVIDE FOR ANNUAL, RATHER THAN QUARTERLY, SURVEYS

SoCalGas and SDG&E reviewed the Proposed Rule's Economic Analysis and identified potential issues with the cost-effectiveness analyses that form the basis for the selection of the proposed control technologies and practices. As described in greater detail in Attachment C, the Economic Analysis overstates the cost-effectiveness (i.e., under-estimates costs and over-estimates emissions) of the LDAR provisions by a factor of three or more. Best-available data indicates that annual, rather than quarterly, LDAR is expected to exceed the target Estimated Emission Reductions at a cost-effectiveness level deemed acceptable by the ARB Economic Analysis.

As discussed in Attachment C, ARB does not justify the need for quarterly LDAR in the Proposed Rule because it relies on unsubstantiated source material. Historical results from an on-going Oil & Gas systems directed inspection and repair program that measures leak reductions indicate that annual surveys using a U.S. Environmental Protection Agency's (EPA) Method 21 gas leak concentration measurement (i.e., screening value) of 10,000 parts per million by volume (ppmv) as a leak definition would result in emission reductions commensurate with or greater than the assumptions that form the basis for the Proposed Regulation. EPA Method 21 gas leak concentration measurements (i.e., screening values) have a very large degree of uncertainty, and gas leak rate/ EPA Method 21 concentration measurement correlations also have a very large degree of uncertainty (i.e., the gas leak associated with a Method 21 concentration measurement can vary by 3 to 4 orders of magnitude). Further, instrumentation performance limitations based on Method 21 QA/QC criteria sets forth a minimum leak definition concentration of 4,000 ppmv for many detectors. Accordingly, EPA Method 21 does not provide an accurate or effective approach to categorize leaks, establish repair thresholds and schedules, or determine regulatory compliance. In addition, a review of the methane mass emission estimates from California oil and gas components in Table B-9 in the CARB EA shows that over 98% of the emissions are from leaks from components with Method 21 screening values greater than or equal to 10,000 ppmv. This indicates a less than 2% incremental increase in emission reductions for a leak definition of Method 21 gas leak concentration measurement of 1,000 ppmv versus 10,000 ppmv. To accomplish ARB's objective to establish regulatory mechanisms to achieve quantifiable GHG reductions, SoCalGas and SDG&E encourage ARB to adopt a leak definition built on a concentration measurement of 10,000 ppmv (as discussed in Comment 14 of Attachment C), and remove EPA Method 21 measured concentration-based rule requirements (e.g., Section 95669(h), (i), and (o), including leak threshold criteria in Tables 1 through 4).

## III. THE PROPOSED REGULATION SHOULD TAKE INTO ACCOUNT POTENTIALLY CONFLICTING OR OVERLAPPING REGULATORY CONSTRAINTS AND REQUIREMENTS

ARB is one of many agencies proposing new regulations for GHG emissions from the oil and gas sector in 2016. Having so many regulatory agencies proposing separate—and sometimes conflicting—rules has the potential to create a dizzying patchwork of regulations that would generate confusion and increase cost to industry beyond the commensurate benefits in GHG and criteria pollutant emissions reductions. Accordingly, SoCalGas and SDG&E urge ARB to avoid adopting regulations that may result in regulatory conflict or overlap.

In addition, as a regulated utility, SoCalGas may not be able to undertake infrastructure repair projects as quickly as ARB contemplates. SoCalGas may be required to obtain prior approval from the California Public Utilities Commission (CPUC) before it can proceed with certain projects (*e.g.*, those constituting capital improvements). SoCalGas urges ARB to account for these and other practical considerations facing regulated utilities, including SoCalGas and SDG&E, when promulgating regulations. The most streamlined and effective way to address this issue would be to exempt Essential Public Services from this rulemaking – as recommended in our prior comment letters dated May 15, 2015 and February 18, 2016. As an alternative, if ARB is opposed to adoption of such an exemption, SoCalGas and SDG&E request that ARB allow greater flexibility with regard to the leak repair timeframes, to take into account regulatory constraints and timelines.

A discussion of the various agencies with proposed rulemakings regarding GHG emissions from the oil and gas sector, as well as a summary of the potential for regulatory overlap, is provided in Attachment E.

## IV. THE ENFORCEMENT PROVISIONS SHOULD BE CLARIFIED TO ACHIEVE REGULATORY OBJECTIVES AND INCENTIVIZE GHG REDUCTIONS

As stated above, SoCalGas and SDG&E strongly support ARB's objective to establish a comprehensive program of regulatory and market mechanisms to achieve real, cost-effective, and quantifiable GHG reductions and acknowledge that enforcement provisions are an essential element of an effective regulatory program. In order for enforcement provisions to achieve regulatory objectives in a cost effective manner and incent the desired behavior, it is critical that the enforcement provisions take into account the efforts of regulated entities to comply and do not penalize entities for activities that could not reasonably have been prevented.

Section 95673(a)(1) of the Proposed Regulation provides that "[a]ny penalties secured by a local air district as the result of an enforcement action that it undertakes to enforce the provisions of this subarticle may be retained by the local air district." This clause passes up on an opportunity to invest penalties toward further GHG reductions. Moreover, Section 95673(a)(1) creates an incentive for local air districts to strictly construe the regulations, find noncompliance, and seek penalties, even where extenuating circumstances may exist (*e.g.*, leak detection technology malfunction). SoCalGas and SDG&E encourage ARB to remove this provision to avoid creating this incentive and develop a regulatory framework that invests penalties toward greater GHG reductions.As an alternative, if ARB declines to remove Section 95674(c) from the Proposed Regulation, SoCalGas and SDG&E recommend the insertion of a clause to encourage regulated entities to offset excess emissions, to further the objective to reduce GHG emissions, as follows:

> § 95674. Enforcement. … (c) Each metric ton of methane emitted in violation of this subarticle constitutes a single, separate, violation of this subarticle **<u>unless such metric ton or its carbon dioxide equivalent is fully offset (for example but without limitation, via the surrender of Cap-and-Trade Program compliance instruments to ARB)</u>**.

In addition, SoCalGas and SDG&E urge ARB to clarify that Section 95674(f) requires intentional conduct and does not strictly impose liability for inadvertent errors. Section 95674(f) of the Proposed Regulation provides that "Submitting or producing inaccurate information required by this subarticle shall be a violation of this subarticle." The operation of such an enforcement provision, if read literally and without consideration of intent or willfulness, would be excessively harsh as inaccurate information may reasonably be "produced" by currently-available monitoring technologies. It is also possible inaccurate information could be inadvertently "submitted" in good faith to ARB or local air districts implementing the Proposed Regulation. Moreover, the first clause in Section 95674(g) covers falsification of information, so this provision is duplicative. Accordingly, SoCalGas and SDG&E recommend deletion of Section 95674(f).

As an alternative, if ARB declines to remove Section 95674(f) from the regulations, then SoCalGas and SDG&E recommend that ARB clarify that the regulation is directed at knowing or intentional conduct:

> § 95674. Enforcement. … (f) **Knowingly s**ubmitting or producing inaccurate information required by this subarticle shall be a violation of this subarticle.

Finally, in furtherance of ARB's cost-effective GHG reduction objectives, the Proposed Regulation should be revised to provide a reasonable opportunity to cure the production or submission of inaccurate information before enforcement authority is activated.

## V. GLOBAL WARMING POTENTIAL SHOULD BE BASED ON A 100-YEAR TIME HORIZON

As stated in our previous comments, the Proposed Regulation should reflect global warming potential (GWP) values based on the 100-year time horizon published in the Intergovernmental Panel on Climate Change (IPCC) Assessment Reports in order to be consistent with other ARB rules as well as with EPA and international convention guidelines. ARB's Regulation for the Mandatory Reporting of Greenhouse Gas Emissions[1] (MRR) requires that covered entities report emissions in metric tonnes of carbon dioxide equivalent ($MTCO_2e$) using the GWP contained in EPA's mandatory GHGs reporting regulation in 40 CFR § 98 (GHGRP): "For the purposes of this article, global warming potential values listed in Table A-1 of 40 CFR Part 98 are used to determine the $CO_2$ equivalent of emissions."[2] In addition, the GWP used in ARB's Cap-and-Trade Program [3] is determined by reference to the GWP used in the MRR and, therefore, similarly uses a 100-year GWP value. [4]

Moreover, the Low Carbon Fuel Standard (LCFS) likewise utilizes a 100-year GWP value for CH4. ARB also uses a 100-year GWP value in its GHG emission inventory program, which tracks statewide GHG emissions levels. [5] Finally, voluntary methane reduction programs also utilize 100-year GWPs for methane. We have prepared and attach a GWP Reference Table, organized by existing governmental programs, which is provided in Attachment F.

Use of a 20-year time horizon for GWP values would undermine ARB's objective to establish a comprehensive program of regulatory and market mechanisms to achieve real, cost-

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[1] 17 Cal. Code Regs. § 95100 et seq. (MRR).

[2] 17 Cal Code Regs. § 95102(66).

[3] 17 Cal. Code Regs. § 95800 et seq.

[4] 17 Cal. Code Regs § 95802(56).

[5] ARB, Global Warming Potentials (May 6, 2015), available at http://www.arb.ca.gov/cc/inventory/background/gwp.htm ("All GWPs used for GHG inventory purposes are considered over a 100-yr timeframe.").

effective, and quantifiable GHG reductions by muddling an otherwise consistent regulatory framework, complicating the assessment of California's progress in GHG emissions reductions, upsetting the settled expectations of stakeholders, and disrupting carbon credit markets. The use of a 20-year GWP value for $CH_4$ of 72 in ARB's Staff Report and Economic Analysis would result in misleading and biased cost estimates for alleged reductions in GHGs. If the 100-year GWP for $CH_4$ used in the MRR and Cap-and-Trade Program of 21 were used, then ARB's estimates of the costs of reductions in $CO_2e$ emissions would have been approximately 3.4 times higher. For example, rather than the alleged $17.27 per $MTCO_2e$, the non-corrected cost of emission reductions due to quarterly Leak Detection and Repair (LDAR) would be approximately $59.21 per $MTCO_2e$. Indeed, as explained in Attachment B, SoCalGas has estimated the true cost to be much higher at approximately $211.19 per $MTCO_2e$ for a methane 100-year GWP of 21. Both of these cost estimates far exceed the marginal abatement cost of other methods of reducing $CH_4$ emissions and also exceed current prices for Cap-and-Trade Program compliance instruments.

## VI. CONCLUSION

SoCalGas and SDG&E would like to thank ARB staff for considering our feedback in previous iterations of the draft regulation. We look forward to additional dialogue on the Proposed Regulation. Please contact me if you have any questions or concerns about these comments.

Sincerely,

*Jerilyn López Mendoza*

Jerilyn López Mendoza
Program Manager
Energy and Environmental Affairs

## ATTACHMENT A: STORAGE WELL MONITORING REQUIREMENTS

The storage well monitoring requirements in §95668(i) should be revised to reflect technology capabilities. In addition, the economic analysis should be revised and benefits should be estimated to support the proposed monitoring requirements. A detailed review of the economic analysis below discusses faulty assumptions and errors in that analysis. Further, the ARB Economic Analysis indicates zero gas savings and emission reductions for these monitoring requirements. With no benefit estimate, the requirements are not adequately justified.

### A. The Proposed Continuing Monitoring Technology is Not Proven. ARB's Analysis Assumes Optical Gas Imaging is Used, and OGI Has Not Been Applied for Continuous Monitoring.

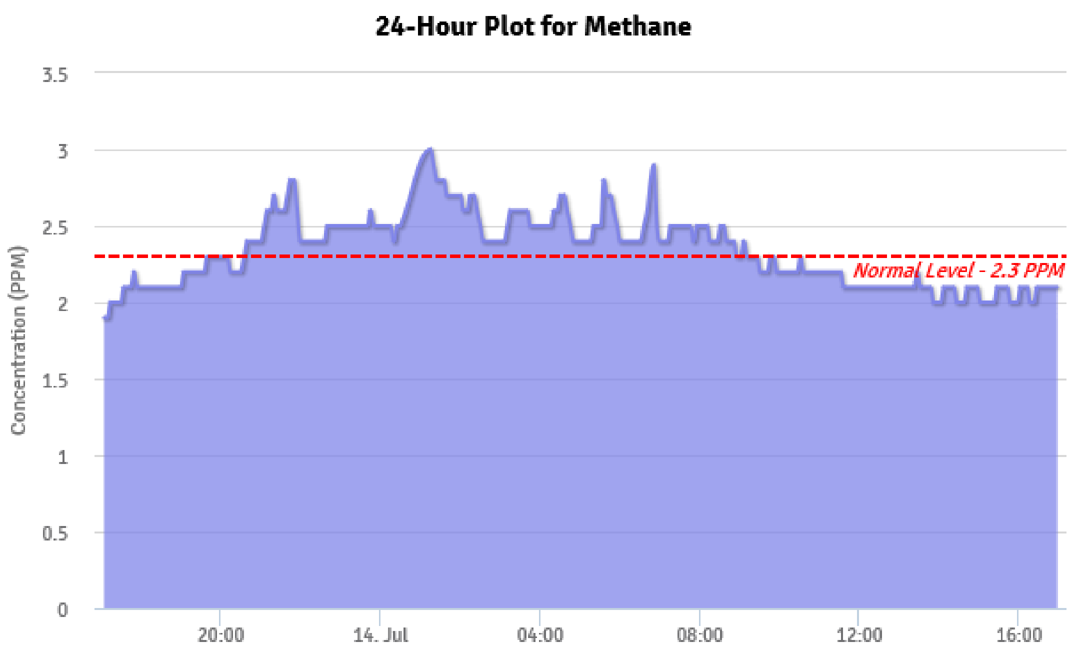
§95668(i)(1)(A) – (C) provide a list of three monitoring requirements. The requirements include: (A) Continuous monitoring of the ambient air. (B) Daily screening of each storage wellhead assembly and surrounding area within 200 feet of the wellhead; or, (C) Continuous monitoring of each storage wellhead assembly and surrounding area within 200 feet of the wellhead. It is not clear from the rule text, but background documents (e.g., the cost estimates in the Economic Analysis) imply that ARB intends for condition (A) to apply, plus either (B) or (C). Comment B provides a detailed review of inadequacies in the economic analysis for these three options, including the daily "manual inspection" option in subsection (B). There are also technological issues associated with the continuous monitoring proposed in subsections (A) and (C).

Support documents such as the Economic Analysis provide minimal detail on the automated monitoring technologies envisioned, and the cost estimates are based on either (1) applying optical gas imaging (OGI) with costs apparently based on presumed costs for infrared (IR) camera, such as the FLIR camera or (2) a combination of unspecified ultrasonic monitors and IR detectors. Thus, it appears that ARB anticipates OGI would be used in a continuous operating mode. SoCalGas does not believe commercial technologies are available for long-term continuous monitoring. This perspective is supported by the U.S. Department of Energy (DOE), and DOE has launched a program to address this technology gap, as discussed below.

A primary concern is that the technology to conduct continuous monitoring as envisioned by ARB is not proven. Although OGI is being adapted to continuous operation, its market entry and established use for methane detection is as a hand held camera for short term field tests rather than continuous operation. In addition, OGI functionality provides leak *detection* but does not quantitate leak rates or provide quantitative assessments such as changes from a baseline level. Similarly, background documents indicate ultrasonic meters could be used for monitoring. There is no detail on the technology, commercial products, or its application. SoCalGas is not aware of such technology that could be used to meet rule requirements.

ARB improperly assumes the availability of a commercial system for fixed mounted autonomous leak detection that requires little or no user intervention. For methane detection, OGI is currently used as a hand held instrument requiring human interface for leak determination. This technology has not been commercially implemented for mounting on a permanent fixture for the purpose of autonomous ambient monitoring, or for leak detection. FLIR has investigated gimbal mounted systems for use in fixed mount applications, but software, system integration, communication, audible and visual alarm or warning system development and integration would need to be tested and validated specifically for the application and distances for storage wellhead and associated equipment. For such use, additional concerns would need to be addressed such as intrinsic safety requirements, additional labor to investigate false positives, QA/QC for continuous operation such as calibration and testing, and an alternative / telephoto lens to allow storage wellhead surveying at greater distances.

In addition, ARB envisions monitoring that triggers action when levels vary by more than 10% from a baseline, which is on the order of 2 ppmv for ambient methane. This monitoring paradigm is not established and fraught with uncertainty. It is unclear how it would be implemented for the two technologies noted by ARB – i.e., OGI or ultrasonic meters. For example, since methane is ubiquitous in the atmosphere from natural and anthropogenic sources, there would likely be site-specific technical challenges that would differ for every storage field, such as: proximity to and prevalence of other methane sources (e.g., agricultural operations, wetlands), natural variability on an hourly, daily, and seasonable basis; wind direction and wind speeds; site topography; other meteorological effects; and surrounding area topography, buildings, and other physical features. Developing the basis for establishing a "baseline" would likely become a research program of indeterminate complexity, and months or years of monitoring could be required to understand the associated uncertainty and variability. Available ambient monitoring data in the vicinity of the Aliso Canyon storage facility, shown in the figure below,[1] indicate that numerous exceedances per day, none associated with a gas leak, would be the norm if a nominal baseline level is used. Constant operations oversight and reporting would be required.




Similarly, assessing a 10% deviation using OGI includes analogous complexities. In addition, if OGI technology is applied (as implied in the Economic Analysis), this technology is not suited for assessing a quantitative change and has not been demonstrated in that capacity. OGI *detects* methane but does not otherwise determine or quantitate an associated measurable value. There are obvious huge technical

[1] http://fenceline.org/porter/data.php. Data from July 14, 2016.

challenges in relying on OGI for the monitoring required by §95668(i)(1)(A) or (C). It is also unclear how ultrasonic technology noted by ARB would be used in this capacity.

Technology gaps for methane monitoring have been acknowledged by the DOE, and its Advanced Research Projects Agency-Energy (ARPA-E) program has launched research projects under the ARPA-E Methane Observation Networks with Innovative Technology to Obtain Reductions (MONITOR) program. This program is targeting development of the type of monitoring envisioned by the §95668(i). DOE notes[2] that MONITOR projects are,

> "…developing innovative technologies to cost-effectively and accurately locate and measure methane emissions associated with natural gas production. Such low-cost sensing systems are needed to reduce methane leaks anywhere from the wellpad to local distribution networks,…"

And, innovation is needed because,

> "Existing methane monitoring devices have limited ability to cost-effectively, consistently, and precisely locate and quantify the rate of the leak."

The ARPA-E MONITOR program includes six projects that would provide methane monitoring systems that provide continuous or near-continuous capabilities for sensing leaks and characterizing leak rates. Another five projects are investigating nascent technologies that may be too early in development to be integrated into a functional system. The program was launched in 2015, and projects will include a demonstration phase if earlier work meets performance objectives, with demonstration testing in the third year. Thus, progress and the potential for success of this national program to address a technology gap will not enter the demonstration phase for about two more years. In addition, there is no assurance of success. Example projects employ OGI approaches in some cases; ultrasonic monitoring implied by the ARB analysis is not being assessed.

The DOE program is indicative of the current state of the science, and shows that technology is not available to address the monitoring envisioned by §95668(i).

Due to technological limitations, SoCalGas believes it is premature to require continuous monitoring as envisioned in §95668(i), and the rule should be revised accordingly.

**B. The ARB Economic Analysis Should be Revised to Address Errors, Faulty Assumptions, and Many Omitted Costs. The Analysis Also Fails to Document an Environmental Benefit.**

**The ARB Economic Analysis Should be Revised to Address Errors, Faulty Assumptions, and Many Omitted Costs. The Analysis Also Fails to Document an Environmental Benefit.**

Storage well monitoring costs are included in Appendix B to the Staff Report, Initial Statement of Reasons. Appendix B is the ARB Economic Analysis (EA), and Section L, "Monitoring Plan," provides ARB estimates for the storage monitoring requirements. While other proposed standards provide an estimate of associated benefits, ARB does not estimate benefits from §95668(i). The lack of a benefit determination is important because monitoring costs are significant and under-estimated in the EA. While SoCalGas understands the underlying intent of adding this section the rule, we do not believe that §95668(i) would result in significant benefits. At most, the proposed storage field Monitoring Plan may result in a brief reduction in the length of time that a major incident leaks (a day or two) and is unlikely

[2] DOE ARPA-E website for MONITOR program; http://arpa-e.energy.gov/?q=arpa-e-programs/monitor

to preclude such an incident. However, since implementation costs are estimated, that analysis is discussed and Attachment A1 includes calculation details.

The storage well monitoring costs in the ARB EA include numerous errors, deficiencies, unsupported data, inconsistencies, and other flaws that cast doubt on the validity and reliability of the cost-effectiveness analyses that is the basis for the selection of the proposed rule storage facility monitoring requirements. The questions raised from review of this analysis implies that ARB staff lack a fundamental understanding of the monitoring equipment and processes, and SoCalGas offers assistance in providing information to improve the basic understanding of implementation challenges associated with the proposed monitoring requirements.

SoCalGas review of the ARB Economic Analysis determined that the EA under-estimates the cost of implementing the proposed rule storage facility monitoring provisions. A review of the ARB EA analysis and comparative alternative analysis is presented in detail in tables below. A summary is provided in Table 1, which indicates the EA under-estimates implementation costs by about a factor of 3 to 4. The data in Table 1 includes:

- The third column lists the EA cost data for storage facility monitoring as presented in Appendix B "Economic Analysis" to the ARB Staff Report: Initial Statement of Reasons (ISOR).
- The fourth column lists the ARB EA cost data for storage facility monitoring with identified corrections (primarily arithmetic errors) to the ARB calculations (identified in Attachment A1)
- The fifth column lists the SoCalGas EA cost data for storage facility monitoring, and the SoCalGas annual implementation cost estimates are about 3 (for Scenario 1) to 4 (for Scenario 2) times greater than the ARB annual implementation cost estimate (refer to the Notes column in Table 1). For Scenario 1, the SoCalGas cost estimate is based on automated monitoring at all wells. For Scenario 2, the SoCalGas cost estimate is based on manual daily monitoring at all wells. Because the SoCalGas Scenario 2 costs are based on actual monitoring costs from recent daily IR camera surveys at the Aliso Canyon storage facility (required by the SCAQMD Abatement Order Case No. 137-76), and the Scenario 1 costs are estimates for an unproven technological approach (i.e., automated monitoring), the Scenario 2 costs are more reliable; thus, SoCalGas's best estimate is that ARB EA cost data for storage facility monitoring is about a factor of four low.

**Table 1. Summary of ARB EA and SoCalGas EA Cost Calculations for the Proposed Rule Storage Facility Monitoring Provisions.***

| Monitoring Plan Cost Parameter | Data ID | CARB EA | CARB EA Corrected Calc Errors | SCGas EA | Notes |
|---|---|---|---|---|---|
| Annual cost of Scenario 1 ($/yr) | A | $6,592,207 | $5,982,247 | $21,557,820 | (SC Gas "A" + "C") / CARB "D" ~ 3 |
| Annual cost of Scenario 2 ($/yr) | B | $10,831,367 | $10,427,407 | $30,507,988 | (SC Gas "B" + "C") / CARB "D" ~ 4 |
| Annual cost of Monitoring Plan Preparation, and Recordkeeping and Reporting ($/yr) | C | $3,459 | $3,456 | $1,385,360 | |

| Monitoring Plan Cost Parameter | Data ID | CARB EA | CARB EA Corrected Calc Errors | SCGas EA | Notes |
|---|---|---|---|---|---|
| Annual Cost of Monitoring Plan Provision Compliance ($/yr) | D | $8,723,290 | $8,208,283 | $27,418,264 | D=(A+B)/2+C |
| Estimated Emission Reductions (mt CO2e/yr) | E | Negative** | Negative** | Negative** | |
| Cost per Metric Ton [$ / mt CO2e] | F | Storage monitoring provides zero emission reduction benefit | | | |

* Attachment A1 details the calculations and data used to develop Table 1.

** If promulgated, the proposed rule requirements for storage facility monitoring would most likely result in a net GHG emissions increase. The economic analysis does not consider the GHG and other pollutant emissions from installing and maintaining the monitoring equipment (e.g., combustion emissions from trucks, man-lifts, etc.) and from daily manual monitoring (i.e., combustion emissions from trucks). SoCalGas estimates that about 280 mt $CO_2$e/yr would be emitted from trucks to transport daily manual inspection teams.

- As summarized in Table 1, the ARB EA significantly under-estimates the cost of the proposed rule storage facility monitoring provisions. In addition, there is little support or documentation for much of the cost information and prescribed technologies. For example, ARB provides no data or evidence that automated leak detection systems have been successfully implemented for storage facility applications. Further, the references for the sources of the automated monitoring system costs (e.g., Caltrol, 2016; ARB 2016) were not provided in Appendix B, and potential options were not evident at the Caltrol website.

It is also very noteworthy that, if promulgated, the proposed rule requirements for storage facility monitoring would most likely result in a net GHG emissions *increase*. The economic analysis does not consider the GHG and other pollutant emissions from installing and maintaining the monitoring equipment (e.g., combustion emissions from trucks, man-lifts, etc.) and from daily manual monitoring (i.e., combustion emissions from trucks). SoCalGas estimates that about 280 mt $CO_2$e/yr would be emitted from trucks to transport daily manual inspection teams.

The primary reasons for the under-estimated costs include:

- The ARB EA includes zero dollars for:
  - Operation and maintenance (e.g., labor, spare parts) of the Scenario 1 automated monitoring system for Scenario 1 (automated monitoring at all wells);
  - The Method 21 leak screening and subsequent leak repair required by §95668(i)(4) and (5);
  - Contingency for undemonstrated technologies. Capital projects cost estimates for new and undemonstrated technologies and equipment applications typically include contingencies of 100 to 200% or more;
  - Monitoring Plan preparation. §95668(i)(1) requires that a Monitoring Plan be developed and submitted to the ARB, and the Monitoring Plan preparation will require monitoring system design, equipment specification, data acquisition and storage system specifications, development of operating and maintenance procedures, procedures for data review and QA, etc.;

- Recordkeeping. §95671(a)(8) lists required recordkeeping requirements that are not included in the costs. The Monitoring Plan to be submitted to the ARB will have data review and recordkeeping associated with the daily operation, maintenance, and calibration of the monitors that are not included in the costs; and
- Management and facility personnel support for survey teams (e.g., scheduling and of leak surveys and repairs with operations).

- ARB under-estimates the cost of ambient monitoring. Multiple monitors will be required for 360 degree monitoring of “ambient” and “facility” methane concentrations. Depending on prevailing winds, facility terrain, and nearby methane sources (e.g., wetlands, agriculture), facility-specific monitor requirements and capital costs could vary considerably. Further, Proposed Regulation §95668(i)(6) requires notifications to ARB, DOGGR, and the local air district within 24 hours of an air monitoring system detecting natural gas that exceeds more than 10 percent of baseline. As discussed above, currently available ambient monitoring technology cannot meet this performance specification at typical ambient methane concentrations (e.g., 2 ppmv), and available data indicates that numerous exceedances would be expected each day. To comply with the rule reporting requirements and adequately investigate each exceedance, SC Gas has estimated costs such that responsible personnel are on-site 24/7 365 days per year;
- ARB under-estimates the O&M costs (e.g., training, periodic maintenance, periodic calibration, data review, data compilation) associated with the ambient monitoring equipment.
- ARB under-estimates the OGI camera per unit cost and the number of required cameras. To ensure camera availability and continuous compliance with the rule, a facility would require a spare camera.
- For Scenario 2, ARB over-estimates the number of wells that are grouped together and can be monitored by a single automated monitoring system, and thus under-estimates the Scenario 2 compliance costs. ARB assumes that 90% of the wells are grouped on a common well pad and, on average, there are three wells per well pad. 10% of the wells are single wells that would be monitored manually. At the five SoCalGas storage facilities, about 54% of the well pads have single wells (vs. 10% assumed by CARB), and about 46% of the well pads have multiple wells and would use the automated daily monitoring system for the CARB EA (vs. 90% assumed by CARB). The SoCalGas wells include about half the wells in the state and would be expected to be typical for the state population of single and grouped wells.
- The cost estimate assumes the monitoring systems have a ten year lifetime, but provide no support or documentation for this contention such as vendor warranties or historical data for like systems. The costs include no scheduled manufacturer required maintenance which would be expected for field equipment to be in service for such an extended period. Since the presumed monitoring systems do not have a track record for continuous applications, require specialized operability such as cooled systems, and use to date in periodic programs shows that device operation relies heavily on a trained operator, it is inappropriate to assume a ten year life.
- SoCalGas experience is that the ARB EA reporting estimates are over an order of magnitude low. Quarterly and annual reporting tasks include data acquisition and QA checks, and report assembly and management review. In addition, CARB requirements will obligate and trigger additional reporting for DOT/PHMSA, DOGGR, SB-1371, CPUC, etc., and data compilation and reporting for external audiences is anticipated.
- The ARB EA used a 5% discount rate based on Cal/EPA guidelines and the rationale that “five percent is the average of what the US Office of Management and Budget recommends (7 percent)

and what US Environmental Protection Agency has used historically for regulatory analysis." However, EPA used a 7% discount rate for the technical support document for the recently promulgated New Source Performance Standards for the oil and gas industry (40 CFR 60, subpart OOOOa)[3] and the ARB EA-cited ICF document (ICF 2014) employs a 10% discount rate. Thus, the CARB EA 5 percent discount rate is not supported by pertinent documents and the SoCalGas EA used a conservative discount rate of 7%.

Other deficiencies and flaws noted in the ARB EA include:

- Numerous arithmetic calculation errors including:
  - "Cost of Scenario 1" on page B-51;
  - "Cost of Ambient Monitoring" on page B-53;
  - "Cost of Scenario 2" on page B-53;
  - "Recordkeeping" on page B-53;
  - "Cost of Monitoring Plan" on page B-54;
- Numerous examples of inconsistent and conflicting data and information:
  - For Scenario 2, the capital cost of the detection equipment is listed as $90,000 in the text and $95,000 in the equation on page B-52;
  - For Scenario 2, the capital cost of the monitoring equipment per well is listed as $54,000 in the text and $90,000 in the equation on page B-52;
  - For Scenario 2, the daily cost of manual inspection is listed as $350 in the text and $285 in the equation on page B-53;
  - For recordkeeping and reporting, the cost of $576 listed as a reporting cost in the text and a recordkeeping cost in the equation on page B-53;
  - For the cost of monitoring plan, does not include the reporting cost in the text and does include the reporting cost in the equation on page B-54.
- The errors noted above raise questions about the veracity of the analysis, and there is a general lack of coherence and critical thinking in the ARB economic analysis. Table 2 summarizes the two scenarios used to estimate the storage monitoring costs in the ARB EA, and identifies several apparently inconsistent and confused cost elements:
  - Both Scenario 1 and Scenario 2 include costs for detection equipment, but the need for and use of this equipment is not discussed or explained;
  - For Scenario 2, the need for "another device capable of detecting leaks" is discussed but the no costs are included for such a device;
  - For the Annual Cost of Monitoring for Scenario 2, it is not evident why manual monitoring was selected for 10% of wells because (1) manual monitoring has an annual cost of $127,750/well-yr (=365 days/yr x $350/well-day), and (2) the ARB EA determined the annual cost for a camera monitor to be $29,700 = $90,000 x 0.130 (CRF) + $18,000.

[3] EPA-HQ-OAR-2010-0505-5120. Background Technical Support Document for the Proposed New Source Performance Standards 40 CFR 60, subpart OOOOa, August 2015.

- For the Annual Cost of Monitoring for Scenario 2, manual monitoring for 10% of the wells has a daily cost of $350 per well.   The ARB EA for LDAR lists an average monitoring cost of $60 per hour (page B-36), and this would infer that CARB estimates almost six hours are required to manually survey each well each day. This is at least an order of magnitude too high (even considering travel) and indicates a lack of consistency and comparability between the different ARB economic analyses.
- For the Annual Cost of Monitoring, Scenario 2 includes on-going costs whereas Scenario 1 has zero on-going costs.

These errors indicate poor quality and a lack of attention to detail that call into question the reliability and validity of the ARB economic analysis.

**Table 2. Comparison of Scenario 1 & Scenario 2 Cost Estimates for Storage Facility Monitoring.**

| Parameter | Scenario 1 | Scenario 2 | Notes / Comments |
|---|---|---|---|
| Description in Introduction | "Compliance with the daily monitoring requirement … | | Page B-50 |
| | using ultrasound monitors in conjunction with optical monitors" | using optical imaging cameras mounted on a permanent fixture" | |
| Annual Cost of Detection Equipment | Purchase one OGI camera per facility: 14 facilities, $95,000 / facility | Purchase one OGI camera per facility: 14 facilities, $95,000 / facility AND "another device capable of detecting leaks" | • For Scenario 1 and Scenario 2, the purpose of the camera is not discussed or evident. M21 instruments required to comply with §95668(i)(4)<br>• For Scenario 2, the cost for "another device capable of detecting leaks" is not included |
| Annual Cost of Monitoring | Purchase 2 ultrasonic monitors and four IR detectors for each well: 408 wells, $83,000 / well | • For 90% of wells, purchase mounted camera monitors: $90,000 each. One monitor to detect leaks at 3 wells with on-going costs of $18,000/monitor-yr<br>• For 10% of wells, daily manual monitoring at $350/well-day | • For Scenario 2, it is not evident why manual monitoring was selected for 10% of wells at an annual cost of $127,750/well-yr (=365 days/yr*$350/well-day) when a camera monitor annual cost is $90,000*0.130 (CRF) + $18,000=$29,700<br>• For both Scenario 1 and Scenario 2, no contingency included in the costs<br>• For Scenario 1, no on-going (i.e., O&M) costs but Scenario 2 has on-going costs |
| Ambient Air Monitoring | Purchase one? ambient monitor per facility: 14 facilities, $84,630 / facility + $89,500 / yr for O&M | Purchase one? ambient monitor per facility: 14 facilities, $84,630 / facility + $89,500 / yr for O&M | • For both Scenario 1 and Scenario 2, no contingency included in the costs |
| Monitoring Plan [§95668(i)(1)] | $0 | $0 | • For both Scenario 1 and Scenario 2, no costs for Monitoring Plan development were included |
| Recordkeeping | $0 | $0 | • §95671(a)(8) lists required recordkeeping that is not included in the costs<br>• The Monitoring Plan to be submitted to the ARB will have recordkeeping associated with the daily operation, maintenance, and calibration of the monitors that are not included in the costs |
| Reporting | $576 | $576 | |

In sum, the ARB analysis generally assumed that the monitoring equipment is purchased and that this transaction is about all that is required. There were no or minimal costs for operating and maintenance labor, ancillary equipment, or contingencies for implementing unproven monitoring systems. A lack of accounting for the facility labor and ancillary equipment required to implement the proposed rule requirements is a consistent trend throughout the ARB economic analyses. The nature of these assumptions cast doubt on the validity and reliability of the cost-effectiveness analyses that ARB developed to justify the proposed rule requirements.

Additional assistance and feedback can be provided, but the comment schedule does not allow the ability to develop detailed comments and alternatives.

### C. Best Practices and Other Potential Regulations Should be Relied On to Address Storage Field Concerns.

Efforts have been underway to develop best practices to provide guidance to operators on how to design and operate, and ensure integrity of underground natural gas storage. Trade associations that address all segments of the natural gas industry, including the American Petroleum Institute (API), Interstate Natural Gas Association of America (INGAA) and American Gas Association (AG), were associated with an effort to develop consensus practices and standards. This culminated in the release of two recommended practices (RP) in September 2015 accredited by the American National Standards Institute. API RP 1171 addresses storage in depleted hydrocarbon reservoirs and aquifer reservoirs, which comprise the vast majority of storage fields. API RP 1170 addresses storage in salt caverns. Members of these trade associations have committed to these practices through board resolutions, and the practices are being implemented by individual companies.

In addition to these practices, President Obama signed recent federal legislation, the PIPES Act of 2016, on June 22, 2016. The PIPES Act requires the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") to issue safety standards for underground storage facilities within 2 years. Also, the U.S. EPA has initiated a process to develop performance standards for *existing* oil and gas facilities, including natural gas storage. This process was initiated on June 3, 2016 with a Notice requesting comment on an oil and gas industry Information Collection Request (ICR), and EPA will use ICR results to develop an existing source regulation. These and other examples of new, planned, or potential regulations are discussed further in Attachment E of these comments.

The new recommended practices and new, planned, and potential federal regulations provide platforms to address concerns about storage fields. SoCalGas recommends depending on those initiatives rather than adopting the proposed storage monitoring requirements in §95668(i).

### D. If §95668(i) is Retained, Revisions are Warranted to Address Technical Issues and the Implementation Schedule.

As discussed above, there are technical challenges and cost implications associated with implementing the proposed rule monitoring provisions for underground storage facilities. If requirements are retained in the final rule, §95668(i) should be revised to provide the opportunity to resolve technical issues and develop a functional monitoring program with feasible criteria.

Applicability of three options in §95668(i)(1)(A) – (C)

The applicability of the three "options" in §95668(i)(1)(A) – (C) should be clearly defined. Based on punctuation, it appears (A) is a stand-alone sentence, and (B) and (C) are a list of two options. In addition, associated documents imply that ARB anticipates item (A), plus (B) or (C) would be implemented. SoCalGas suggests that any one of the three options is more than sufficient to provide regular and ongoing assurance of the site status. Providing technical challenges associated with continuous monitoring can be addressed, any of the three items listed would provide real time or daily data on site integrity, and layered criteria are not warranted.

In addition, selecting one option provides operators the ability to consider a near-term "manual" program based on item (B) while technology for continuous monitoring systems matures and becomes commercially available. Operators could opt to migrate from a manual process to more automated approach as warranted by technological advances.

Implementation schedule and baseline determination

A longer implementation schedule should be allowed, especially if ARB considers retaining mandatory continuous monitoring (i.e., §95668(a)(1)(A) plus (B) or (C) is required). Additional time and effort is needed to identify, evaluate, and validate technologies that meet the proposed criteria as well as operator expectations for performance and reliability. As discussed above in Comment A, an extended implementation period will likely be required to develop a monitoring "baseline" that addresses site-specific variability and uncertainty. In addition, additional time may be needed to allow continuous monitoring technologies to mature.

ARB should consider a staged implementation approach that includes a design and testing phase prior to requiring compliance with performance objectives. Near-term efforts to assess performance by judging deviations from baseline monitoring values unnecessarily raises questions about the ability to conform to rule requirements, because there are questions regarding the technical basis for the standard and uncertainty in establishing a baseline. Since there are many unknowns in understanding a baseline and perceived "measurable" 10 % deviations (see Comment A), an extended schedule is warranted. SoCalGas recommends an approach that allows an operator to conduct monitoring and record results, and report to ARB after one year regarding monitoring status, baseline determination, and the basis for determining "actionable" levels. Based on insight gained as monitoring data is collected, a plan can be devised for full implementation of monitoring requirements that judge performance versus baselines values.

ARB should consider staged implementation and out-year definition of performance criteria

With better defined criteria established through a phase in period, detailed site-specific monitoring plans may not be necessary. As discussed in these comments, there are significant challenges and uncertainty in implementing the proposed storage monitoring criteria. While technology-forcing regulations are sometimes adopted, the implementation challenges extend beyond technology availability to include questions regarding performance measures. For example, issues with establishing a baseline and judging a 10% change are noted above. Because of many uncertainties, the monitoring program may initially be more characteristic of a data gathering research program. Such an approach is fraught with uncertainties that could affect compliance determinations if performance measures immediately apply. Compliance ambiguity due to uncertainties within the regulatory process is an untenable scenario for operators, and an approach that acknowledges shortcomings in the proposed standard is warranted if ARB chooses to implement the proposed requirements.

Thus, if §95668(i) is retained, a staged approach should be considered that includes monitoring, recordkeeping and reporting, but provides for an out-year re-assessment that determines and defines performance objectives. A multi-year, staged program could provide the ability to develop a functional monitoring approach and avoid unnecessary controversy from a program that implements criteria that are not well-supported or technically proven.

## Attachment A1. SoCalGas Economic Analysis of Proposed Rule Storage Monitoring Provisions

| Monitoring Plan Cost Parameter | Data ID | CARB EA | CARB EA Corrected Calc Errors | SCGas EA | Notes / Source(s) of CARB and SCGas Data. SC Gas proposed rule compliance costs are generally average costs for 5 storage facilities: Aliso Canyon (AC), Honor Rancho (HR), Playa Del Rey (PDR), Goleta (GOL), and Montebello (MONT) |
|---|---|---|---|---|---|
| Scenario 1 Automated Monitoring at all wells | | | | | |
| **Annual Cost of Detection Equipment** | | | | | |
| OGI camera purchase cost (each Facility) | A | $95,000 | $95,000 | $0 | - CARB EA: Page B-50. the CARB EA states that this scenario uses OGI cameras (plural) mounted on a permanent fixture, but it is not clear what a single camera mounted at facility would detect? Also, this monitoring scenario includes monitoring at each well with two ultrasonic monitors and four IR detectors. Further, CARB does not discuss that permanently mounted OGI cameras is a demonstrated technology.<br>- CARB EA does not include any costs (labor, spare parts) for O&M of these cameras, nor allow for spare cameras to ensure continuous compliance.<br>- SC Gas EA: Permanently mounted OGI cameras would not be included in a SCGas automated monitoring system |
| Number of facilities | B | 14 | 14 | 14 | CARB EA page B-50 |
| Capital recovery factor | C | 0.130 | 0.130 | 0.142 | - CARB EA: page B-51 (10 years at 5%)<br>- SCGas EA: (10 years at 7%) |
| Annual cost for daily leak monitoring teams ($/yr) | C1 | $0 | $0 | $0 | - CARB EA page B-51 - Not applicable, CARB included zero costs for IR camera operation and maintenance.<br>- SCGas EA: Permanently mounted OGI cameras would not be included in a SCGas automated monitoring system |
| Annual cost for facility support ($/yr) | C2 | $0 | $0 | $0 | - CARB EA page B-51 - Not applicable, CARB included zero costs for facility personnel to support IR camera teams.<br>- SCGas EA: Permanently mounted OGI cameras would not be included in a SCGas automated monitoring system |
| Annual cost of detection equipment ($/yr) | D | $172,900 | $172,900 | $0 | D = A*B*C<br>- CARB EA page B-51 |
| **Annual Cost of Monitoring Equipment** | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| Automated daily monitoring system purchase cost (each well) | E | $83,000 | $83,000 | $77,000 | - CARB EA: Page B-50.<br>- CARB EA does not include any costs (labor, spare parts) for O&M of these monitors, nor allow for spare monitors to ensure continuous compliance.<br>- has this technology been demonstrated on this scale for this duration? If this is a novel technology or application, then it would be prudent to include a large contingency (e.g., 100%)<br>- SC Gas EA: 2 pair IR 5500 at each well + 10% contingency. Conservative installed cost |
| Number of wells | F | 408 | 408 | 408 | CARB EA Page B-51 |
| Capital recovery factor | G | 0.130 | 0.130 | 0.142 | - CARB EA: page B-51 (10 years at 5%)<br>- SCGas EA: (10 years at 7%) |
| Well monitoring on-going annual cost (each Well) ($/well-yr) | G1 | NA | NA | $5,000 | - CARB EA: page B-51. Not applicable, CARB included zero costs for monitoring equipment operation and maintenance. - SCGas EA: estimates costs for maintenance, calibration, reporting, data review, and data compilation for external audiences. Estimate 5% of equipment is replaced each year +$3,500 annual O&M per well. |
| Capital costs for Method 21 detectors to screen detected leaks in accordance with §95668(i)(4) ($/facility) | G2 | $0 | $0 | $11,000 | - CARB EA: page B-51. Not applicable, CARB included zero costs for Method 21 monitoring.<br>- SCGas EA: Cost estimate for two Method 21 instruments for each facility to ensure continuous compliance (must screen detected leaks within 24 hours)<br>- split with LDAR |
| Labor costs for Method 21 screening of detected leaks in accordance with §95668(i)(4) ($/facility-yr) | G3 | $0 | $0 | $58,240 | - CARB EA: page B-51. Not applicable, CARB included zero costs for Method 21 monitoring.<br>- SCGas EA: Must screen detected leaks within 24 hours, assume personnel on duty or on call, and estimate 14 man-hours per week on average to comply. G3=52 (weeks/yr) *14 (hr/week) *$80/hr need to calibrate equipment, derive to location, and measure concentration. |

| | | | | | |
|---|---|---|---|---|---|
| Annual labor costs for repair of Method 21 detected leaks in accordance with §95668(i)(5) ($/facility-yr) | G4 | $0 | $0 | $33,280 | - CARB EA: page B-51. Not applicable, CARB included zero costs for Method 21 monitoring.<br>- SCGas EA: Estimate 8 man-hours per week on average to comply. G4=52 (weeks/yr) *10 (hr/week) *$80/hr.<br>- Estimates for year 1 (leak = 10,000 ppmv by M21), would need to add hours for lower ppmv leak definition (e.g., 1,000 ppmv)<br>- costs can varies greatly depending on component<br>- does not address costs of major repairs, e.g., may need a rig for a component at wellhead |
| Annual material costs for repair of Method 21 detected leaks in accordance with §95668(i)(5) ($/facility-yr) | G5 | $0 | $0 | $41,600 | - CARB EA: page B-51. Not applicable, CARB included zero costs for Method 21 monitoring.<br>- SCGas EA: small repairs, truck use, consumables, small components/valves, etc.<br>- Estimates for year 1 (leak = 10,000 ppmv by M21), would need to add $$ for lower ppmv leak definition (e.g., 1,000 ppmv)<br>- costs can varies greatly depending on component<br>- does not address costs of major repairs; e.g., large valves can cost about $30,000, may need a rig for a component at wellhead |
| Annual cost to screen and repair Method 21 detected leaks in accordance with §95668(i)(4), (5) ($/facility-yr) | G6 | $0 | $0 | $134,682 | - CARB EA: page B-51. Not applicable, CARB included zero costs for Method 21 monitoring.<br>- SCGas EA: G5=G2*G+G3+G4+G5 |

| | | | | | |
|---|---|---|---|---|---|
| Well monitoring on-going annual cost to comply with the requirements of §95668(i)(6) (each Facility) ($/facility-yr) | G7 | $0 | $0 | $0 | - CARB EA: page B-51 - SCGas EA: The requirements of Proposed rule §95668(i)(6) requires notifications to ARB, DOGGR, and the local air district within 24 hours of an air monitoring system detecting natural gas that exceeds more than 10 percent of baseline. As discussed above, current monitoring technology cannot meet this performance specification at typical ambient methane concentrations (e.g., 2 ppmv), and available data indicates that numerous exceedances would be experienced each day. It is not clear whether this requirement applies to automated monitoring at wells, and this analysis assumes that it does <u>not</u> apply. However, if the §95668(i)(6) requirements do apply to automated monitoring at wells, then numerous dedicated full time positions would be required such that responsible personnel are on-site 24/7 365 days per year to comply with the rule reporting requirements and adequately investigate each exceedance. Annual compliance costs would increase by an estimated factor of 5. |
| Annual Cost of Monitoring Equipment ($/yr) | H | $4,402,320 | $4,402,320 | $8,386,620 | - CARB EA page B-51, H = E*F*G<br>- SC Gas EA: H = E*F*G+F*G1+B*G6 |
| **Annual Cost of Ambient Air Monitoring** | | | | | |
| Ambient monitoring equipment purchase cost (each Facility) | I | $84,630 | $84,630 | $400,000 | - CARB EA: page B-51<br>- SCGas EA: Estimated facility capital cost for multiple units (Boreal TDL based-technology) for 360 degree coverage. Actual capital costs will depend on requirements for “ambient” and “facility” monitoring.<br>- Note that these instruments will not have the sensitivity to routinely be able to distinguish a "10% change from baseline" to comply with the requirements of §95668(i)(6) at typical ambient methane concentrations (e.g., 2 ppmv). |
| Number of facilities | J | 14 | 14 | 14 | CARB EA page B-51 |
| Capital recovery factor | K | 0.130 | 0.130 | 0.142 | - CARB EA: page B-51 (10 years at 5%)<br>- SCGas EA: (10 years at 7%) |

| | | | | | |
|---|---|---|---|---|---|
| Ambient monitoring on-going annual operating cost (each Facility) ($/facility-yr) | L | $89,500 | $89,500 | $52,000 | - CARB EA: page B-51<br>- SCGas EA: estimated costs for maintenance, calibration, spare parts, etc. Estimate 5% of monitors is replaced each year +$10,000 annual O&M per monitor |
| Ambient monitoring on-going annual cost to comply with the requirements of §95668(i)(6) (each Facility) ($/facility-yr) | L1 | $0 | $0 | $832,000 | - CARB EA: page B-51<br>- SCGas EA: The requirements of Proposed rule §95668(i)(6) requires notifications to ARB, DOGGR, and the local air district within 24 hours of an air monitoring system detecting natural gas that exceeds more than 10 percent of baseline. As discussed above, currently available ambient monitoring technology cannot meet this performance specification at typical ambient methane concentrations (e.g., 2 ppmv), and available data indicates that numerous exceedances would be expected each day. To comply with the rule reporting requirements and adequately investigate each exceedance, SC Gas has estimated five dedicated full time positions such that responsible personnel are on-site 24/7 365 days per year. |
| Annual Cost for ambient monitoring ($/yr) | M | $1,407,027 | $1,407,027 | $13,171,200 | M = J*(I*K+L+L1) - CARB EA: page B-51 |
| **Annual cost of Scenario 1** | | | | | |
| Annual cost of Scenario 1 ($/yr) | N | $6,592,207 | $5,982,247 | $21,557,820 | - CARB EA: page B-51. <u>CARB EA calculations are incorrect</u>.<br>- Corrected CARB EA: N=D+H+M<br>- SC Gas EA: N=D+H+M |
| | | | | | |
| **Scenario 2** | | **Automated Monitoring at 90% of wells, Daily Monitoring at 10% of wells** | | **Daily Manual Monitoring at all Wells** | |
| **Annual Cost of Detection Equipment** | | | | | |
| OGI camera purchase cost (each Facility) | O | $95,000 | $95,000 | $230,000 | - CARB EA Page B-52<br>- SC Gas EA: IR camera at $110,000, spare IR camera at $110,000 to ensure continuous compliance, plus $10,000 in miscellaneous startup costs |
| Number of facilities | P | 14 | 14 | 14 | CARB EA page B-50 |
| Capital recovery factor | Q | 0.130 | 0.130 | 0.142 | - CARB EA page B-51 (10 years at 5%)<br>- SCGas EA (10 years at 7%) |

| | | | | | |
|---|---|---|---|---|---|
| Annual cost for daily leak monitoring teams ($/facility-yr) | Q1 | $0 | $0 | $936,000 | - CARB EA page B-52: Not applicable, CARB included zero costs for IR camera operation and maintenance. - SCGas EA: average cost for daily IR camera monitoring at the 5 SC Gas storage facilities. 6 crews of 2 people, 7 days a week to cover 5 storage facilities. Based on recent costs to implement IR camera surveys at Aliso Canyon per the SCAQMD Abatement Order Case No. 137-76. |
| Annual cost for facility support ($/facility-yr) | Q2 | $0 | $0 | $135,000 | - CARB EA page B-52: Not applicable, CARB included zero costs for facility personnel to support IR camera teams. - SCGas EA: average cost for 0.75 facility personnel to support daily IR camera monitoring at the 5 SC Gas storage facilities, includes coordination of survey teams and repairs with operations, and initial data review/validation and organization, safety measures, and project management. Based on recent costs to implement IR camera surveys at Aliso Canyon per the SCAQMD Abatement Order Case No. 137-76. |
| Capital costs for Method 21 detectors to screen detected leaks in accordance with §95668(i)(4) ($/facility) | Q3 | $0 | $0 | $11,000 | - CARB EA: page B-51. Not applicable, CARB included zero costs for Method 21 monitoring. - SCGas EA: Cost estimate for two Method 21 instruments for each facility to ensure continuous compliance (must screen detected leaks within 24 hours) - split with LDAR |
| Labor costs for Method 21 screening of detected leaks in accordance with §95668(i)(4) ($/facility-yr) | Q4 | $0 | $0 | $58,240 | - CARB EA: page B-51. Not applicable, CARB included zero costs for Method 21 monitoring. - SCGas EA: Must screen detected leaks within 24 hours, assume personnel on duty or on call, and estimate 14 man-hours per week on average to comply. =52 (weeks/yr) *14 (hr/week) *$80/hr need to calibrate equipment, derive to location, and measure concentration. |
| Annual labor costs for repair of Method 21 detected leaks in accordance with §95668(i)(5) ($/facility-yr) | Q5 | $0 | $0 | $33,280 | - CARB EA: Not applicable, CARB included zero costs for Method 21 monitoring. - SCGas EA: Estimate 8 man-hours per week on average to comply. =52 (weeks/yr) *8 (hr/week) *$80/hr. Small repairs, truck use, consumables, small components/valves, etc. - Estimates for year 1 (leak = 10,000 ppmv by M21), would need to add hours for lower ppmv leak definition (e.g., 1,000 ppmv) - costs can varies greatly depending on component - does not address costs of major repairs, e.g., may need a rig for a component at wellhead |

| | | | | | |
|---|---|---|---|---|---|
| Material costs for repair of Method 21 detected leaks in accordance with §95668(i)(5) ($/facility-yr) | Q6 | $0 | $0 | $41,600 | - CARB EA: page B-51. Not applicable, CARB included zero costs for Method 21 monitoring.<br>- SCGas EA: small repairs, truck use, consumables, small components/valves, etc.<br>- Estimates for year 1 (leak = 10,000 ppmv by M21), would need to add $$ for lower ppmv leak definition (e.g., 1,000 ppmv)<br>- costs can varies greatly depending on component<br>- does not address costs of major repairs; e.g., large valves can cost about $30,000, may need a rig for a component at wellhead |
| Annual cost of detection equipment ($/yr) | R | $172,900 | $172,900 | $479,108 | R = (O+Q3)*P*Q<br>- CARB EA: page B-51 |
| Annual cost of daily leak surveys ($/yr) | R1 | NA | NA | $17,336,788 | R1 = R+P*(Q1+Q2+Q4+Q5+Q6) |
| **Annual Cost of Monitoring** | | | | | |
| Automated daily monitoring system at 90% of wells purchase cost (every 3 wells) | S | $90,000 | $90,000 | NA | - CARB EA Page B-51, assumes one monitor can detect leaks at three wells for 90% of the wells<br>- SC Gas EA based on all wells are monitored daily "manually" by IR camera teams |
| Number of wells | T | 408 | 408 | 408 | CARB EA Page B-52 |
| Percent of wells using automated daily monitoring system | U | 90% | 90% | 0% | - CARB EA: Page B-52. Note, at the 5 SC Gas facilities, about 54% of the well pads have single wells, and about 46% of the well pads have multiple wells and would use the automated daily monitoring system for the CARB EA. Thus, SCGas costs for daily manual monitoring are under-estimated.<br>- SC Gas EA: based on all wells are monitored daily "manually" by IR camera teams |
| Number of wells monitored by each automated monitoring system | V | 3 | 3 | NA | - CARB EA: Page B-52<br>- SC Gas EA: based on all wells are monitored daily "manually" by IR camera teams |
| Capital recovery factor | W | 0.130 | 0.130 | NA | - CARB EA: Page B-52 (10 years at 5%)<br>- SC Gas EA: based on all wells are monitored daily "manually" by IR camera teams |

| | | | | | |
|---|---|---|---|---|---|
| Annualized capital cost for automated monitoring equipment ($/yr) | X | $1,432,080 | $1,432,080 | NA | - CARB EA: Page B-52. X=(S*T*U*W)/V<br>- SC Gas EA: based on all wells are monitored daily "manually" by IR camera teams |
| Annual on-going cost for each automated monitoring equipment ($/monitor-yr) | Y | $18,000 | $18,000 | NA | - CARB EA: Page B-52.<br>- SC Gas EA: based on all wells are monitored daily "manually" by IR camera teams |
| Annual on-going cost for automated monitoring equipment ($/yr) | Z | $2,203,200 | $2,203,200 | NA | - CARB EA: Page B-53. Z=(T*U*Y)/V<br>- SC Gas EA: based on all wells are monitored daily "manually" by IR camera teams |
| Percent of wells using manual daily monitoring system | AA | 10% | 10% | NA | - CARB EA: Page B-53.<br>- SC Gas EA: based on all wells are monitored daily "manually" by IR camera teams. Refer to costs above. |
| Daily cost of manual well monitoring ($/well-day) | AB | $350 | $350 | NA | - CARB EA: Page B-53. - SC Gas EA: based on all wells are monitored daily "manually" by IR camera teams. Refer to costs above. |
| Annual cost of manual well monitoring ($/yr) | AC | $5,212,200 | $5,212,200 | NA | - CARB EA: Page B-53. AC=T*AA*AB*365 (days/yr)<br>- SC Gas EA: based on all wells are monitored daily "manually" by IR camera teams. Refer to costs above. |
| **Annual Cost of Ambient Air Monitoring** | | | | | |
| Ambient monitoring equipment purchase cost (each Facility) | AD | $84,630 | $84,630 | $400,000 | - CARB EA: page B-53<br>- SCGas EA: Estimated facility capital cost for multiple units (Boreal TDL based-technology) for 360 degree coverage. Actual capital costs will depend on requirements for “ambient” and “facility” monitoring.<br>- Note that these instruments will not have the sensitivity to routinely be able to distinguish a "10% change from baseline" to comply with the requirements of §95668(i)(6) at typical ambient methane concentrations (e.g., 2 ppmv). |
| Number of facilities | AE | 14 | 14 | 14 | CARB EA: page B-53 |
| Capital recovery factor | AF | 0.130 | 0.130 | 0.142 | - CARB EA: page B-53 (10 years at 5%)<br>- SCGas EA: (10 years at 7%) |
| Ambient monitoring on-going annual cost (each Facility) ($/facility-yr) | AG | $89,500 | $89,500 | $52,000 | - CARB EA: page B-53<br>- SCGas EA: estimated costs for maintenance, calibration, spare parts, etc. Estimate 5% of monitors is replaced each year +$10,000 annual O&M per monitor |

| | | | | | |
|---|---|---|---|---|---|
| Ambient monitoring on-going annual cost to comply with the requirements of §95668(i)(6) (each Facility) ($/facility-yr) | AG1 | $0 | $0 | $832,000 | - CARB EA: page B-53<br>- SCGas EA: The requirements of Proposed rule §95668(i)(6) requires notifications to ARB, DOGGR, and the local air district within 24 hours of an air monitoring system detecting natural gas that exceeds more than 10 percent of baseline. As discussed above, currently available ambient monitoring technology cannot meet this performance specification at typical ambient methane concentrations (e.g., 2 ppmv), and available data indicates that numerous exceedances would be expected each day. To comply with the rule reporting requirements and adequately investigate each exceedance, SC Gas has estimated five dedicated full time positions such that responsible personnel are on-site 24/7 365 days per year. |
| Annual Cost for ambient monitoring ($/yr) | AH | $1,306,525 | $1,407,027 | $13,171,200 | - CARB EA: page B-53, CARB EA calculations are incorrect.<br>- Corrected CARB EA: AH = AE*(AD*AF+AG+AG1)<br>- SC Gas EA: AH = AE*(AD*AF+AG+AG1) |
| **Annual cost of Scenario 2** | | | | | |
| Annual cost of Scenario 2 ($/yr) | AI | $10,831,367 | $10,427,407 | $30,507,988 | - CARB EA page B-53. CARB EA calculations are incorrect.<br>- Corrected CARB EA. AI=R+X+Z+AC+AH.<br>- SC Gas EA. AI=R1+AH. |
| | | | | | |
| **Record-keeping and Reporting** | | | | | |
| Businesses impacted by Monitoring Plan | AJ | 6 | 6 | 6 | CARB EA page B-53 |
| Annual cost of reporting (each business) ($/business-yr) | AK | $576 | $576 | $20,800 | - CARB EA: page B-53<br>- SCGas EA: SCGas estimates 1 hours/week day (0.125 FTE) for reporting for both scenarios ($80/hr). Quarterly and annual reporting requirements.<br>- CARB requirements obligate and trigger additional reporting for DOT/PHMSA, DOGGR, SB-1371, CPUC, etc.<br>- Also anticipate data compilation and reporting for external audiences |

| | | | | | |
|---|---|---|---|---|---|
| Annual cost of recordkeeping (each facility) ($/facility-yr) | AL | $0 | $0 | $83,200 | - CARB EA: page B-53, not addressed by CARB EA - SCGas EA: SCGas estimates 4 hours/ week day (0.5 FTE) for final data review and QC, and recordkeeping for both scenarios ($80/hr). Includes records of all leaks and associated repairs, pre- and post-repair Method 21 leak concentration measurements, final data review and validation, and all records stipulated in the Facility Monitoring Plan. |
| Monitoring Plan development ($/facility) [§95668(i)(1)] | AM | $0 | $0 | $20,000 | - CARB EA: page B-53, not addressed by CARB EA<br>- SCGas EA: includes monitoring system design, equipment specification, development of QA processes, implementation procedures, recordkeeping, etc. Interface with CARB |
| Monitoring Plan annual updates ($/facility-yr) [§95668(i)(1)] | AN | $0 | $0 | $4,000 | - CARB EA: page B-53, not addressed by CARB EA<br>- SCGas EA: updates based on lessons learned and monitoring system modifications, particularly for early years. |
| Annual Cost for Monitoring Plan ($/facility-yr) | AO | $0 | $0 | $6,840 | - CARB EA: page B-53, not addressed by CARB EA<br>- SCGas EA: AO=AF*AM+AN |
| Annual cost of monitoring plan development, and recordkeeping and reporting ($/yr) | AP | $3,459 | $3,456 | $1,385,360 | - CARB EA: page B-53. <u>CARB EA calculations are incorrect</u>.<br>- Corrected CARB EA: AP=AJ*AK+AE*AL*AE+AO<br>- SCGas EA: AP=AJ*AK+AE*AL*AE+AO |
| | | | | | |
| **Annual Cost of Monitoring Plan** | | | | | |
| Annual Cost of Monitoring Plan Provision Compliance ($/yr) | AQ | $8,723,290 | $8,208,283 | $27,418,264 | - CARB EA page B-54. <u>CARB EA calculations are incorrect</u>.<br>- Corrected CARB EA. AQ=(N+AI)/2+AP<br>- SCGas EA. AQ=(N+AI)/2+AP |

**Attachment B: Review of Appendix B "Economic Analysis" to the CARB Staff Report**

## Overview

Appendix B of the Economic Analysis of the Proposed Regulation significantly underestimates the costs of implementing the Proposed Rule storage facility monitoring provisions. This appears to be the result of flaws in some of the data and assumptions that form the basis of the Economic Analysis. As set forth in the attached cover letter, SoCalGas and SDG&E recommend that ARB delay the adoption of these rules to give stakeholders and experts more time to provide necessary input—particularly with respect to costs and technical feasibility.

SoCalGas offers our assistance in providing information to improve the basic understanding of the affected emission sources. As an introduction, a brief review of the CARB EA of the proposed rule Well Stimulation provision is illustrative

## Well Stimulation Provision

The Economic Analysis estimates that six separator/incinerator control systems will be sufficient to control emissions from 1,200 well stimulation activities per year. This equates to 200 well stimulations per year (or about four per week) for each control system. The Economic Analysis does not cite a specific source for the underlying data or assumptions to support this estimation. SoCalGas encourages ARB to consider adjusting the Economic Analysis to take into account the following:

First, discussion with production personnel estimates full compliance with this rule provision would likely require at least twelve full-time control systems. Well stimulation treatments typically require one to three days to complete. Assuming an average of two days per well stimulation treatment, and considering real-world scheduling delays (*e.g.*, schedule changes due to mechanical and other problems, unexpected well issues, inclement weather, control equipment downtime for maintenance, etc.), a minimum of twelve, as opposed to six, full-time control systems would be required.

Second, the Economic Analysis should be revised to take into account the following anticipated costs, which currently are missing from the estimate:

- transporting the separator/incinerator control systems from site to site. At a minimum, a heavy duty trailer and large towing (*e.g*., tractor-trailer) truck would need to be purchased and dedicated to each control system;
- ancillary equipment including pipes, hoses, connectors, tools, etc.;
- operating labor. At least one full time person would be required to drive each truck and operate each control system. Additional personnel would be required to set up and break-down the equipment at each site (e.g., connect pipes and hoses);
- travel costs including per diem for the operator and truck fuel;
- disruption / delay of well stimulation activities due to implementation of the control requirements;
- control system maintenance labor and spare parts; and
- management and scheduling.

Moreover, the cost estimate assumes the control systems will have ten-year lifetimes, but do not cite the basis for the underlying assumption that equipment that is in continuous use and transported on a trailer over oil-field roads for ten years will remain functional for at least ten years. SoCalGas does not believe this is a realistic assumption.

In addition, the cost estimate does not consider the GHG and other pollutant emissions from operating the control equipment (*e.g*., combustion emissions from the incinerator and separator heater, gas leaks from separator components) and driving the tractor-trailer truck.

In sum, the ARB analysis assumed that the control equipment is purchased and that this transaction is all that is required. There were no costs for any labor or transportation or ancillary equipment, and a lack of accounting for the facility labor and ancillary equipment required to implement the proposed rule control practices and technologies is a consistent trend throughout the ARB economic analyses.

Additional assistance and feedback can be provided, but the comment schedule does not allow the ability to develop detailed comments and alternatives for all affected sources. Similar examples of erroneous or questionable assumptions and analysis are available for other sources affected by the proposed rule. For these reasons, SoCalGas urges ARB to delay implementation in order to obtain additional input from stakeholders and experts.

The following review of the ARB proposed rule LDAR provisions demonstrates that ARB has overestimated the cost-effectiveness of the LDAR provisions by a factor of three or more.

## Leak Detection and Repair Estimates

The Economic Analysis for the proposed rule LDAR provisions appears to under-estimate the cost-per-metric-ton of $CO_2$e emissions controlled by a factor of about three, as summarized in Table 1. In addition to a direct comparison with the CARB LDAR costs, Table 1 presents SoCalGas LDAR cost-effectiveness estimates based on several assumptions, as discussed below.

- The second column lists the CARB Economic Analysis cost and emissions data for quarterly LDAR as presented in Appendix B "Economic Analysis" to the CARB Staff Report: Initial Statement of Reasons (ISOR).
- The third column lists the CARB Economic Analysis cost and emissions data for quarterly LDAR with identified corrections to the CARB calculations (identified in Attachment A and Attachment B)
- The fourth column lists the SoCalGas Economic Analysis cost and emissions data for quarterly LDAR, and the SoCalGas cost per metric ton reduction estimates are about three times greater than the CARB cost per metric ton reduction estimates. Note that SoCalGas estimates higher annual emissions reductions from LDAR than CARB (90% vs. 60%). This reduction estimate is based on measured leak reduction data and is discussed in Comment 10 of Attachment A.
    - For comparison, the fifth column lists the SoCalGas Economic Analysis cost and emissions data for quarterly LDAR using the 100-year Global Warming Potential (GWP) for methane of 21, and these SoCalGas cost per metric ton reduction estimates are about an order of magnitude greater than the CARB cost per metric ton reduction estimates. The CARB EA used a 20-year GWP for methane of 72 whereas SoCalGas believes the standard 100-year GWP for methane of 21 is more appropriate. The many reasons that the 100-year GWP is more appropriate for this analysis are presented in SoCalGas and SDG&E Comments on Revised Draft Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.[1]

[1] SoCalGas and SDG&E Comments on Revised Draft Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, February 18, 2016.

- The sixth column lists the SoCalGas Economic Analysis cost and emissions data for annual LDAR, and these are about the same magnitude as the CARB cost per metric ton reduction estimates. Note that SoCalGas estimates higher annual emissions reductions from annual LDAR than CARB estimates from quarterly LDAR (80% vs. 60%). This reduction estimate is based on measured leak reduction data and is discussed in Comment 10 of Attachment A.
  - For comparison, the seventh column lists the SoCalGas Economic Analysis cost and emissions data for annual LDAR using the more appropriate 100-year GWP for methane of 21 as discussed above, and the SoCalGas cost per metric ton estimates are about 3 times greater than the CARB cost per metric ton reduction estimates.

The data in Table 1 demonstrate that annual, rather than quarterly, LDAR is expected to exceed the target Estimated Emission Reductions at a cost-effectiveness level deemed acceptable by the CARB Economic Analysis.

**Table 1. Summary of CARB EA and SoCalGas EA Cost-Effectiveness Calculations for the Proposed Rule LDAR Provisions.***

| Parameter | CARB EA (Quarterly, GWP = 72) | CARB EA (Quarterly, GWP = 72) Corrected | SCGas EA (Quarterly, GWP = 72) | SCGas EA (Quarterly, GWP = 21) | SCGas EA (Annual, GWP = 72) | SCGas EA (Annual, GWP = 21) |
|---|---|---|---|---|---|---|
| Cost of LDAR Program [$ / yr] | $10,182,299 | $9,646,628 | $36,870,175 | $36,870,175 | $9,485,109 | $9,485,109 |
| Baseline (Uncontrolled) Methane Emissions [mt CH4 / yr] | 13,650 | 13,805 | 11,351 | 11,351 | 11,351 | 11,351 |
| Global Warming Potential [mt CO2e / mt CH4] | 72 | 72 | 72 | 21 | 72 | 21 |
| Annual Emissions Reductions from LDAR | 60% | 60% | 90% | 90% | 80% | 80% |
| Estimated Emission Reductions (mt CO2e / yr) | 589,680 | 596,376 | 735,545 | 214,534 | 653,818 | 190,697 |
| Annual Value of Gas Saved [$ / yr] | $1,547,683 | $1,565,257 | $889,045 | $889,045 | $790,262 | $790,262 |
| Cost per Metric Ton [$ / mt CO2e] | $17.27 | $16.18 | $50.13 | $171.86 | $14.51 | $49.74 |
| Cost per Metric Ton with Gas Savings [$ / mt CO2e] | $14.64 | $13.55 | $48.92 | $167.72 | $13.30 | $45.60 |

* Attachment A and Attachment B detail the calculations and data used to develop Table 1.

As summarized in Table 1, the CARB EA severely under-estimates the cost per metric ton of CO2e emission reductions. The primary reasons for the under-estimation include:

- CARB over-estimated the baseline/uncontrolled methane leak emissions. The uncontrolled methane leak emissions listed in Table B-9 of the CARB EA are based on total hydrocarbon (THC) emission factors from a CAPCOA document[2], and CARB assumed that 100% of the THC was methane rather than considering that transmission and storage natural gas contains about 95% methane by volume (about 93% methane by weight) and production and processing natural gas contains about 78.8% methane by volume (about 60% methane by weight). In addition, several of the emission factors in Table B-9 were incorrectly copied from the CAPCOA document. These errors combined to over-estimate methane emissions by about 20%.

- CARB relied upon discussions with LDAR contractors for LDAR surveys cost information, and these contractors have a very strong incentive to provide lowest possible implementation costs because promulgation of quarterly LDAR requirements would be very beneficial to their business. LDAR implementation costs provided in the most recent economic analysis published by ICF International (ICF 2016)[3] are more than twice the average rate provided by the LDAR contractors, and these were used for the SoCalGas EA. Based on the text on page B-36 of the CARB EA and discussion of "person year", it is not clear that CARB staff understand that the industry standard practice is two person survey teams, both for safety reasons and to record data including number of components inspected as required by the proposed rule.
- The CARB EA did not include any costs for facility personnel to support the LDAR surveys including training, scheduling, safety orientation, survey team escort and support, leak repair, etc. SoCalGas experience is that that one FTE will be required to support the LDAR project per year.
- SoCalGas experience is that the CARB EA recordkeeping and reporting estimates are about an order of magnitude too low. These tasks include collecting and tracking daily LDAR data (including leaks found and follow-up repair and verification measurements), audio-visual inspection requirements at unmanned sites, data QA checks (e.g., compare daily LDAR data to final reports), and report assembly and review.
- The CARB EA assumed that the facilities financially benefit from the gas savings; however, transmission and storage facilities do not own the gas they transport and storage and do not benefit economically from LDAR gas savings. This is commonly acknowledged in literature on methane reduction programs from EPA and others.
- The CARB EA valued gas savings at $3.44 per Mcf which is considerably higher than current spot prices for natural gas.
- The CARB EA used a 5% discount rate based on Cal/EPA guidelines and the rationale that "five percent is the average of what the US Office of Management and Budget recommends (7 percent) and what US Environmental Protection Agency has used historically for regulatory analysis." However, EPA used a 7% discount rate for the technical support document for the recently promulgated New Source Performance Standards for the oil and gas industry (40 CFR 60, subpart OOOOa)[4] and the CARB EA-cited ICF document (ICF 2014) employs a 10% discount rate. Thus, the CARB EA 5 percent discount rate is not supported by pertinent documents and the SoCalGas EA used a conservative discount rate of 7%.

Other deficiencies and flaws noted in the CARB EA include:

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[2] CAPCOA, ARB. 1999. The California Air Resources Board Staff California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities.

[3] ICF 2016. "Economic Analysis of Methane Reduction Potential from Natural Gas Systems," ICF International, May 2016

[4] EPA-HQ-OAR-2010-0505-5120. Background Technical Support Document for the Proposed New Source Performance Standards 40 CFR 60, subpart OOOOa, August 2015.

- The calculation of "Cost per Ton with Savings" on page B-41 is incorrect.
- Engineering units are frequently incorrect (e.g., the units for the Conversion Factor of 836.2 should be scf/kg-mole rather than kg/kg-mole as listed on page B-40).
- Table B-9 of the CARB EA lists 1,318,700 components to survey, but page B-35 calculates a total of 1,339,185 that includes 20,485 well casings at heavy oil facilities and 939 compressors * 11 components per compressor, and this total is used to calculate the survey team years. Thus, the CARB EA total component basis for compliance costs (1,339,185) differs from the CARB EA total component basis for emission estimates (1,318,700) and is a flaw in the analysis. Further, the 1,339,185 component total is flawed because:
  - The 20,485 well casings at heavy oil facilities do not require quarterly LDAR, they require measurement of "the natural gas flow rate from the well casing vent annually by direct measurement" [§95668(h)(1)]; thus, the well casings should not be included in the LDAR components total.
    - An additional deficiency in the CARB EA is that an economic analysis for the proposed rule well casings provision is not provided.
  - Compressors (and the associated drivers) typically have many more than 11 components. Table W-1B to Subpart W of Part 98 lists a total of 259 components per compressor in the production segment to be used for GHG emissions reporting. Larger compressors employed in transmission and storage would be expected to have a higher total component count.

Finally, it is notable that the CARB EA states,

> "the capital cost of larger repairs is not included based upon the assumption that these repairs would need to be made regardless of an LDAR program; because ***the operator would repair these parts regardless of the LDAR program [emphasis added]***"

And

> "Emissions were estimated using emission factors from CAPCOA guidelines (CAPCOA, 1999), which also accounted for 'super leaker' components. These are components that leak at a rate several times the rate of what is expected from a typical component, and make up the majority of emissions. Several studies that have reported measurements of $CH_4$ emissions from natural gas production sites share a common observation-the existence of skewed emissions distributions, where a small number of sites or facilities account for a large proportion of emissions."

These two statements suggest that the majority of gas leak emissions would be controlled regardless of the implementation of an LDAR program. This simple assumption is very compelling and casts doubt on the need for and viability of the proposed rule LDAR provision.

## Attachment A. SoCalGas Economic Analysis of Proposed Rule LDAR Provisions

| LDAR Cost Parameters for Cost of LDAR Program | Data ID | CARB EA (Quarterly, GWP = 72) | CARB EA (Quarterly, GWP = 72) Corrected Calc Errors | SCGas EA (Quarterly, GWP = 72) | SCGas EA (Quarterly, GWP = 21) | SCGas EA (Annual, GWP = 72) | SCGas EA (Annual, GWP = 21) | Notes / Source(s) of CARB and SCGas Data |
|---|---|---|---|---|---|---|---|---|
| Number of components to survey [components] | A | 1,318,700 | 1,318,700 | 1,318,700 | 1,318,700 | 1,318,700 | 1,318,700 | - CARB EA: Table B-9<br>- SC Gas (and CARB Corrected): Used same total as CARB EA to be consistent with basis for annual emissions estimate (i.e., data in Table B-9) |
| Work hours per year [hr/yr] | B | 2,080 | 2,080 | 2,080 | 2,080 | 2,080 | 2,080 | CARB EA: page B-36 |
| Components surveyed per hour per survey team [components / team-hr] | C | 34 | 34 | 34 | 34 | 34 | 34 | CARB EA: page B-36, CARB refers to Person Year (PY) rather than survey team year. |
| Number of persons per survey team [persons / team] | D | 1? | 1? | 2 | 2 | 2 | 2 | - CARB EA: page B-36. CARB EA page B-36, CARB refers to Person Year (PY) rather than survey team year. <u>It is not clear that CARB understands that a 2 man team is standard for LDAR.</u><br><u>- SCGas EA: used the standard two persons per survey team</u>. Two people are generally required for all survey teams for safety reasons and to record data including number of components inspected. |
| Components inspected in one survey team year [components / team-yr] | E | 68,250 | 70,720 | 70,720 | 70,720 | 70,720 | 70,720 | E=B*C<br>- Note that CARB calculated 68,250 on CARB EA page B-36, and this appears to be a <u>calculation error</u> |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Survey team years for **<u>one survey</u>** of all components [team-yrs] | F | 19.6 | 18.6 | 18.6 | 18.6 | 18.6 | 18.6 | F = A/E, note that CARB calculated 19.6 on CARB EA page B-36, and this appears to be due to the use of inconsistent component population data. Table B-9 lists 1,318,700 components to survey, but page B-35 calculates a total of 1,339,185 that includes 20,485 well casings at heavy oil facilities and 939 compressors * 11 components per compressor and this total is used to calculate the survey team years. This <u>component total is incorrect</u> for several reasons:<br>- it is different from the component total in Table B-9 that is the basis for the emissions estimate<br>- the 20,485 well casings at heavy oil facilities do not require quarterly LDAR, they require measurement of "the natural gas flow rate from the well casing vent annually by direct measurement" [§95668(h)(1)]; thus, the well casings should not be included in the LDAR components total<br>- compressors typically have many more components than 11. Table W-1B to Subpart W of Part 98 lists a total of 259 components per compressor in the production segment to be used for GHG emissions reporting. Larger compressors employed in transmission and storage would be expected to have a higher total compressor count. |
| Average survey team days per facility [team-days/facility] | F1 | 6.4 | 6.1 | 6.1 | 6.1 | 6.1 | 6.1 | F1= (F*B)/(L*8) |
| *Check calc* | | *6.1* | *6.1* | *6.1* | *6.1* | *6.1* | *6.1* | *= (A/L)/(C*8)* |
| Survey team cost per hour [$ /team-hr] | G | $60.00 | $60.00 | $142.06 | $142.06 | $142.06 | $142.06 | - CARB EA: page B-36<br>- SCGas EA: rate from ICF 2016 |
| Number of inspections/ surveys per year [surveys / yr] | H | 4 | 4 | 4 | 4 | 1 | 1 | CARB EA: page B-37 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Facility personnel support - hours/survey (scheduling, safety, escort, leak repairs & documentation, etc.) [hrs / survey] | I | 0 | 0 | 48.5 | 48.5 | 48.5 | 48.5 | - Not addressed by the CARB EA<br>- SCGas EA: estimate of hours required for storage facility reps = one hour for every hour survey team on site, based on historical support for Leak surveys at storage facilities (e.g., training, scheduling, safety orientation, survey team escort and support, leak repair, etc. ) I = F1*8 (hr/day) |
| Facility personnel support, labor rate [$/hr] | J | 0 | 0 | $80.00 | $80.00 | $80.00 | $80.00 | - Not applicable for the CARB EA<br>- SCGas EA: data from storage facility reps |
| Annual Cost for Inspections per survey team year [$ / survey team-yr?] | K | $499,200 | $499,200 | $1,847,539 | $1,847,539 | $461,885 | $461,885 | K=B*G*H+B*H*J<br>- Note, CARB EA calcs are confusing and engineering units are not clear. |
| Number of Facilities [facilities] | L | 799 | 799 | 799 | 799 | 799 | 799 | CARB EA page B-37 |
| Set up cost per facility [$ / facility] | M | $1,500 | $1,500 | $1,500 | $1,500 | $1,500 | $1,500 | CARB EA page B-37 |
| Capital recovery factor | N | 0.130 | 0.130 | 0.244 | 0.244 | 0.244 | 0.244 | - CARB EA: page B-37, assumes same LDAR vendor conducts inspections at every facility for 10 years<br>- Based on experience, SCGas assumes LDAR vendors are periodically changed, assume after 5 years on average for all facilities and discount rate of 7% |
| Total Setup Cost [$] | O | $155,805 | $155,805 | $292,434 | $292,434 | $292,434 | $292,434 | O=L*M*N |
| Businesses impacted by LDAR Provision [businesses] | P | 201 | 201 | 201 | 201 | 201 | 201 | CARB EA page B-37 |
| Average number of facilities per business [facilities / business] | P1 | 5.24 | 3.98 | 3.98 | 3.98 | 3.98 | 3.98 | P1 = R/P |
| Annual cost of reporting [$ / business-yr] | Q | $144 | $144 | $2,864 | $2,864 | $956 | $956 | - CARB EA: page B-37<br>- Based on experience, SCGas estimates 0.25 man-days to assemble and QA data from each survey, and 4 hours to prepare report and obtain report approval for the business ($80/hr) Q = P1*H*J*0.25*8+4*J |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Facilities impacted by LDAR [facilities] | R | 1,054 | 799 | 799 | 799 | 799 | 799 | CARB EA: page B-37 lists 1,054 facilities and this total includes Well Casing Facilities. However, as discussed under ID F, Well Casing Facilities have an annual gas volumetric rate measurement requirement that is not LDAR, and the reporting costs for Well Casing Facilities should not be included. |
| Annual cost of recordkeeping per facility impacted by LDAR [$ / facility-yr] | S | $192 | $192 | $1,942 | $1,942 | $485 | $485 | - CARB EA: page B-37<br>- SCGas EA: estimates 1 hour for recordkeeping for each day the survey team is on-site ($80/hr) S=H*F1*1 (hr/day) * J |
| Recordkeeping and Reporting Cost [$ / yr] | T | $231,312 | $182,352 | $2,127,092 | $2,127,092 | $580,013 | $580,013 | T=P*Q+R*S |
| Cost of LDAR Program [$ / yr] | U | $10,182,299 | $9,646,628 | $36,870,175 | $36,870,175 | $9,485,109 | $9,485,109 | U = F*K+O+T |
| *check calc* | | *$9,695,588* | *$9,646,628* | *$36,870,175* | *$36,870,175* | *$9,485,109* | *$9,485,109* | *= (A*H((G+J))+O+T* |
| | | | | | | | | |
| **LDAR Cost Parameters for <u>Emissions and LDAR Emission Reductions</u>** | **ID** | **CARB EA (Quarterly, GWP = 72)** | **CARB EA (Quarterly, GWP = 72) Corrected Calc Errors** | **SCGas EA (Quarterly, GWP = 72)** | **SCGas EA (Quarterly, GWP = 21)** | **SCGas EA (Annual, GWP = 72)** | **SCGas EA (Annual, GWP = 21)** | **Notes / Source(s) of CARB and SCGas Data** |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Baseline (Uncontrolled) Methane Emissions [mt CH4 / yr] | V | 13,650 | 13,805 | 11,351 | 11,351 | 11,351 | 11,351 | - CARB EA: Table B-9<br>- SCGas EA: refer to Attachment B. CARB over-estimated the baseline/uncontrolled gas leak methane emissions. The uncontrolled methane leak emissions listed in Table B-9 of the EA are based on total hydrocarbon (THC) emission factors from a CAPCOA document, and CARB assumed that 100% of the THC was methane rather than considering that transmission and storage natural gas contains about 94.9% methane by volume (about 92.5% methane in THC by weight) and production and processing natural gas contains about 78.8% methane by volume (about 60% methane in THC by weight). In addition, three of the emission factors in Table B-9 were incorrectly copied from the CAPCOA document. These errors combined to over-estimate methane emissions by about 20%. |
| Global Warming Potential [mt CO2e / mt $CH_4$] | W | 72 | 72 | 72 | 21 | 72 | 21 | - CARB EA: page B-38<br>- SCGas EA: considers both 20-yr GWP (= 72) and 100-yr GWP (= 21) |
| Baseline (Uncontrolled) Carbon Dioxide Equivalents Emissions [metric tons CO2e / yr] | X | 982,800 | 993,960 | 817,272 | 238,371 | 817,272 | 238,371 | X=V*W |
| Annual emissions reductions from LDAR | Y | 60% | 60% | 90% | 90% | 80% | 80% | - CARB EA: page B-38<br>- SCGas EA: 80% from CAPP study based on <u>measured</u> emissions associated with <u>annual</u> DI&M ("Management of Fugitive Emissions at Upstream Oil and Gas Facilities", Canadian Association of Petroleum Producers (CAPP), January 2007.) 90% for quarterly estimated based on assumption of linear leak growth rate moderated by practical considerations of extended repair times for critical components and unsafe to access components. |
| Estimated emission reductions (mt CO2e / yr) | Z | 589,680 | 596,376 | 735,545 | 214,534 | 653,818 | 190,697 | Z=X*Y |
| | | | | | | | | |

| **LDAR Cost Parameters for <u>Savings from LDAR Emission Reductions</u>** | **ID** | **CARB EA (Quarterly, GWP = 72)** | **CARB EA (Quarterly, GWP = 72) Corrected Calc Errors** | **SCGas EA (Quarterly, GWP = 72)** | **SCGas EA (Quarterly, GWP = 21)** | **SCGas EA (Annual, GWP = 72)** | **SCGas EA (Annual, GWP = 21)** | **Notes / Source(s) of CARB and SCGas Data** |
|---|---|---|---|---|---|---|---|---|
| Volume Percent methane in natural gas | AA | 94.9% | 94.9% | 89.9% | 89.9% | 89.9% | 89.9% | - CARB EA: page B-39<br>- SCGas EA: assumes 31.3% of the annual leakage is from natural gas with 78.8% methane and 68.7% of the annual leakage is from natural gas with 94.9% methane - based on 2104 O&G GHG Inventory which had 1.82 million mt methane emissions from O&G extraction and production and 3.99 million mt methane emissions from pipelines (http://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_sector_sum_2000-14ch4.pdf) |
| Volume of Gas Saved [scf] | AB | 449,907,765 | 455,016,608 | 592,696,445 | 592,696,445 | 526,841,285 | 526,841,285 | AB = (V*Y*836.2 [scf/kg-mol]*1,000 [kg/mt]) / (16.04 [kg CH4 / kgmol CH4] * AA) |
| Natural gas value [$ / Mcf] | AC | $3.44 | $3.44 | $3.00 | $3.00 | $3.00 | $3.00 | - CARB EA: page B-40<br>- SCGas EA: estimated current spot price for field gas (e.g., more C2, C3, C4 and value than pipeline gas) |
| Percent of gas savings that has economic value for the facility | AD | 100% | 100% | 50% | 50% | 50% | 50% | - CARB EA: page B-40 assumes 100% of the gas savings has value for the facility<br>- SCGas EA: estimates that 50% of the gas savings has value for the facility because Transmission and Storage facilities do not own the gas they transport and store, and do not benefit economically from LDAR gas savings. |
| Annual value of gas saved [$ / yr] | AE | $1,547,683 | $1,565,257 | $889,045 | $889,045 | $790,262 | $790,262 | AE=(AB*AC*AD) / 1,000 [Mcf/scf] |
| | | | | | | | | |
| **LDAR Cost Parameters for <u>Cost per Metric Ton of the LDAR Provision</u>** | **ID** | **CARB EA (Quarterly, GWP = 72)** | **CARB EA (Quarterly, GWP = 72) Corrected Calc Errors** | **SCGas EA (Quarterly, GWP = 72)** | **SCGas EA (Quarterly, GWP = 21)** | **SCGas EA (Annual, GWP = 72)** | **SCGas EA (Annual, GWP = 21)** | **Notes / Source(s) of CARB and SCGas Data** |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Cost per Metric Ton [$ / mt CO2e] | AF | $17.27 | $16.18 | $50.13 | $171.86 | $14.51 | $49.74 | AF = U / Z |
| Cost per Metric Ton with gas savings [$ / mt CO2e] | AG | $14.64 | $13.55 | $48.92 | $167.72 | $13.30 | $45.60 | AG = (U - AE) / Z |

## Attachment B. SoCalGas Estimate of Proposed Rule LDAR Provision Methane Emission Reductions

| LDAR Emissions Parameter | Component | ID | CARB EA (Table B-9) | CARB EA (corrected) | SC Gas EA | Notes / Source(s) of CARB and SCGas Data |
|---|---|---|---|---|---|---|
| **Components < 10,000 ppm** | | | | | | |
| **Number of Components** | Valves | A | 236,131 | 236,131 | 236,131 | CARB EA: Table B-9 |
| | Connectors | B | 870,766 | 870,766 | 870,766 | |
| | Flanges | C | 158,486 | 158,486 | 158,486 | |
| | Open end lines | D | 692 | 692 | 692 | |
| | Pump Seals | E | 2,312 | 2,312 | 2,312 | |
| | Others (compressors, hatches, etc.) | F | 21,088 | 21,088 | 21,088 | |
| **Emission Factors (kgTHC/hr/source)** | Valves | G | - | 3.50E-05 | 3.50E-05 | From Table IV-2c CAPCOA 1999, THC Emission Factors (THC EF) assumes only Gas/Light Liquid service, no Light Crude or Heavy Crude Oil |
| | Connectors | H | - | 1.20E-05 | 1.20E-05 | |
| | Flanges | I | - | 2.80E-05 | 2.80E-05 | |
| | Open end lines | J | - | 2.40E-05 | 2.40E-05 | |
| | Pump Seals | K | - | 9.96E-04 | 9.96E-04 | |
| | Others (compressors, hatches, etc.) | L | - | 1.47E-04 | 1.47E-04 | |
| **g THC per Component per Year** | Valves | M | - | 307 | 307 | M=G*(8760 hr/yr)*(1000g/kg) |
| | Connectors | N | - | 105 | 105 | N=H*(8760 hr/yr)*(1000g/kg) |
| | Flanges | O | - | 245 | 245 | O=I*(8760 hr/yr)*(1000g/kg) |
| | Open end lines | P | - | 210 | 210 | P=J*(8760 hr/yr)*(1000g/kg) |
| | Pump Seals | Q | - | 8,725 | 8,725 | Q=K*(8760 hr/yr)*(1000g/kg) |
| | Others (compressors, hatches, etc.) | R | - | 1,288 | 1,288 | R=L*(8760 hr/yr)*(1000g/kg) |
| **g CH4 per Component per Year** | Valves | S | 307 | 307 | 252 | - CARB calculation uses equations for M through R with apparent errors for V and W (V= 210, W= 8725). The results, S through X, are mistaken as g CH4 when the units are g THC (i.e., CARB assumes the THC is 100% methane). This error is propagated in the subsequent calculations. |
| | Connectors | T | 105 | 105 | 86 | |
| | Flanges | U | 245 | 245 | 202 | |
| | Open end lines | V | 1,288 | 210 | 173 | |
| | Pump Seals | W | 1,288 | 8,725 | 7,174 | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Others (compressors, hatches, etc.) | X | 1,288 | 1,288 | 1,059 | - SCGas EA assumes 31.3% of the annual leakage is from natural gas with 78.8% methane and 68.7% of the annual leakage is from natural gas with 94.9% methane - based on 2104 O&G GHG Inventory which had 1.82 million mt methane emissions from O&G extraction and production and 3.99 million mt methane emissions from pipelines (http://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_sector_sum_2000-14ch4.pdf). . Conversions to weight % methane are I.D. CH and CH, respectively. (e.g., S = 0.313*M*CH + 0.687*M*CI) |
| **MT CH4 per Year** | Valves | Y | 72.49 | 72.40 | 59.52 | Y=S*A/(1,000,000 g/MT) |
| | Connectors | Z | 91.43 | 91.53 | 75.26 | Z=T*B/(1,000,000 g/MT) |
| | Flanges | AA | 38.83 | 38.87 | 31.96 | AA=U*C/(1,000,000 g/MT) |
| | Open end lines | AB | 0.89 | 0.15 | 0.12 | AB=V*D/(1,000,000 g/MT) |
| | Pump Seals | AC | 2.98 | 20.17 | 16.59 | AC=W*E/(1,000,000 g/MT) |
| | Others (compressors, hatches, etc.) | AD | 27.16 | 27.16 | 22.33 | AD=X*F/(1,000,000 g/MT), note that CARB calculated 27.06 on CARB EA Table B-9, and this appears to be a calculation error |
| **Global Warming Potential** | | GWP | 72 | | | |
| **MT CO2e per Year** | Valves | AE | 5,219.4 | 5,212.6 | 4,285.8 | AE=GWP*Y |
| | Connectors | AF | 6,583.0 | 6,590.5 | 5,418.7 | AF=GWP*Z |
| | Flanges | AG | 2,795.7 | 2,798.9 | 2,301.2 | AG=GWP*AA |
| | Open end lines | AH | 64.2 | 10.5 | 8.6 | AH=GWP*AB |
| | Pump Seals | AI | 214.4 | 1,452.4 | 1,194.1 | AI=GWP*AC |
| | Others (compressors, hatches, etc.) | AJ | 1,948.2 | 1,955.2 | 1,607.5 | AJ=GWP*AD, note that CARB calculated 1,948.2 on CARB EA Table B-9, and this appears to be a calculation error |
| | | | | | | |
| **Components > 10,000 ppm** | | | | | | |
| **Number of Components** | Valves | AK | 5,367 | 5,367 | 5,367 | CARB EA Table B-9 |
| | Connectors | AL | 19,790 | 19,790 | 19,790 | |
| | Flanges | AM | 3,602 | 3,602 | 3,602 | |
| | Open end lines | AN | 16 | 16 | 16 | |
| | Pump Seals | AO | 53 | 53 | 53 | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Others (compressors, hatches, etc.) | AP | 477 | 477 | 477 | |
| **Emission Factors (kgTHC/hr/source)** | Valves | AQ | 1.39E-01 | 1.39E-01 | 1.39E-01 | From Table IV-2c CAPCOA 1999, THC Emission Factors (THC EF) assumes only Gas/Light Liquid service, no Light Crude or Heavy Crude Oil |
| | Connectors | AR | 2.59E-02 | 2.59E-02 | 2.59E-02 | |
| | Flanges | AS | 6.10E-02 | 6.10E-02 | 6.10E-02 | |
| | Open end lines | AT | 5.49E-02 | 5.49E-02 | 5.49E-02 | |
| | Pump Seals | AU | 8.90E-02 | 8.90E-02 | 8.90E-02 | |
| | Others (compressors, hatches, etc.) | AV | 1.38E-01 | 1.38E-01 | 1.38E-01 | |
| **g THC per Component per Year** | Valves | AW | - | 1,214,136 | 1,214,136 | AW=AQ*(8760 hr/yr)*(1000g/kg) |
| | Connectors | AX | - | 226,884 | 226,884 | AX=AR*(8760 hr/yr)*(1000g/kg) |
| | Flanges | AY | - | 534,360 | 534,360 | AY=AS*(8760 hr/yr)*(1000g/kg) |
| | Open end lines | AZ | - | 480,924 | 480,924 | AZ=AT*(8760 hr/yr)*(1000g/kg) |
| | Pump Seals | BA | - | 779,640 | 779,640 | BA=AU*(8760 hr/yr)*(1000g/kg) |
| | Others (compressors, hatches, etc.) | BB | - | 1,205,376 | 1,205,376 | BB=AV*(8760 hr/yr)*(1000g/kg) |
| **g CH4 per Component per Year** | Valves | BC | 1,217,645 | 1,214,136 | 998,251 | - CARB calculation uses equations for AW through BB with apparent errors for BC, BE, BF, BG and BH. Calculated values are BC=1,214,136 BE=534,360 BF=480,924 BG =779,640 and BH 1,205,376. The results, BC through BH, are mistaken as g CH4 when it is g THC (i.e., CARB assumes the THC is 100% methane). This error is propagated in the subsequent calculations.<br><br>- SCGas EA assumes 31.3% of the annual leakage is from natural gas with 78.8% methane and 68.7% of the annual leakage is from natural gas with 94.9% methane - based on 2104 O&G GHG Inventory which had 1.82 million mt methane emissions from O&G extraction and production and 3.99 million mt methane emissions from pipelines (http://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_sector_sum_2000-14ch4.pdf). Conversions to weight % methane are I.D. CH and CH, respectively. (e.g., BC = 0.313*AW*CH + 0.687*AW*CI) |
| | Connectors | BD | 226,884 | 226,884 | 186,542 | |
| | Flanges | BE | 480,924 | 534,360 | 439,346 | |
| | Open end lines | BF | 1,208,880 | 480,924 | 395,411 | |
| | Pump Seals | BG | 1,208,880 | 779,640 | 641,013 | |
| | Others (compressors, hatches, etc.) | BH | 1,208,880 | 1,205,376 | 991,049 | |

| | | | | | | |
|---|---|---|---|---|---|---|
| **MT CH4 per Year** | Valves | BI | 6,534.64 | 6,516.27 | 5,357.62 | BI=AK*BC/(1,000,000 g/MT), note that CARB calculated 6,534.64 on CARB EA Table B-9, and this appears to be a calculation error |
| | Connectors | BJ | 4,490.06 | 4,490.03 | 3,691.67 | BJ=AL*BD/(1,000,000 g/MT), note that CARB calculated 4,490.06 on CARB EA Table B-9, and this appears to be a calculation error |
| | Flanges | BK | 1,732.27 | 1,924.76 | 1,582.52 | BK=AM*BE/(1,000,000 g/MT), note that CARB calculated 1,732.27 on CARB EA Table B-9, and this appears to be a calculation error |
| | Open end lines | BL | 19.02 | 7.69 | 6.33 | BL=AN*BF/(1,000,000 g/MT), , note that CARB calculated 19.02 on CARB EA Table B-9, and this appears to be a calculation error |
| | Pump Seals | BM | 63.53 | 41.32 | 33.97 | BM=AO*BG/(1,000,000 g/MT), note that CARB calculated 63.53 on CARB EA Table B-9, and this appears to be a calculation error |
| | Others (compressors, hatches, etc.) | BN | 577.17 | 574.96 | 472.73 | BN=AP*BH/(1,000,000 g/MT), note that CARB calculated 577.17 on CARB EA Table B-9, and this appears to be a calculation error |
| **MT CO2e per Year** | Valves | BO | 470,494.1 | 469,171.3 | 385,748.3 | BO = GWP * BI, note that CARB calculated 470,494.1 on CARB EA Table B-9, a propagation of previous calculation error. |
| | Connectors | BP | 323,284.7 | 323,282.5 | 265,799.9 | BP = GWP * BJ, note that CARB calculated 323, 284.7 on CARB EA Table B-9, a propagation of previous calculation error. |
| | Flanges | BQ | 124,723.2 | 138,583.1 | 113,941.7 | BQ = GWP * BK , note that CARB calculated 124,GWP3.2 on CARB EA Table B-9, a propagation of previous calculation error. |
| | Open end lines | BR | 1,369.4 | 554.0 | 455.5 | BR = GWP * BL, note that CARB calculated 1,369.4 on CARB EA Table B-9, a propagation of previous calculation error. |
| | Pump Seals | BS | 4,574.4 | 2,975.1 | 2,446.1 | BS = GWP * BM, note that CARB calculated4, 574.4 on CARB EA Table B-9, a propagation of previous calculation error. |
| | Others (compressors, hatches, etc.) | BT | 41,556.5 | 41,397.4 | 34,036.6 | BT = GWP * BN, note that CARB calculated 41,556.5 on CARB EA Table B-9, a propagation of previous calculation error. |
| | | | | | | |
| **Total** | Components | BU | 1,318,780 | 1,318,780 | 1,318,780 | Sum of Components, A-F and AK-AP, note that CARB calculated 1,318,700 on CARB EA Table B-9, a propagation of previous calculation error. |
| | MT CH4/Year | BV | 13,650 | 13,805 | 11,351 | Sum of MT CH4/Year, Y-AD and BI-BN |

| | | | | | | |
|---|---|---|---|---|---|---|
| | MT CO2e/Year | BW | 982,827 | 992,028 | 815,637 | Sum of MT CO2e/Year, AE-AJ and BO-BT |
| | | | | | | |
| **Composition of Natural Gas** | **Species** | | **Composition** | | | |
| **Production, mol %** | methane | BX | 78.8% | | | Composition of methane in Natural Gas from CARB EA p. B-15 Percentages of ethane, propane, higher hydrocarbons and non-hydrocarbons estimated based on relative percentages reported for typical associated gas composition in Wikipedia. |
| | ethane | BY | 6.14% | | | |
| | propane | BZ | 7.36% | | | |
| | higher hydrocarbon | CA | 6.03% | | | |
| | non-hydrocarbon | CB | 1.67% | | | |
| | | | 100.00% | | | |
| **Pipeline, vol%** | methane | CC | 95.00% | | | Composition of Natural Gas from Table A-44 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014 |
| | ethane | CD | 2.79% | | | |
| | propane | CE | 0.48% | | | |
| | higher hydrocarbon | CF | 0.30% | | | |
| | non-hydrocarbon | CG | 1.43% | | | |
| | | | 100.00% | | | |
| **Weight % of Methane in THC** | | | | | | |
| **Production** | methane, weight % | CH | 59.52% | | | CH=BX*16.04/[BX*16.04 + BY*30.07 + BZ*44.10 + CA*58.12] and assumes that all of the higher hydrocarbons are butane, MW 58.12 g/mol |
| **Pipeline** | methane, weight % | CI | 92.56% | | | CI=CC*16.04/[CC*16.04 + CD*30.07 + CE*44.10 + CF*58.12] and assumes that all of the higher hydrocarbons are butane, MW 58.12 g/mol |

**Attachment C: Comments on Definitions and Standards**

**Comments on Proposed Rule Definitions**

1. §95667(19). For the definition of "flash or flashing" we suggest the following change (added text in ***bold italics***) "gas ~~entrained~~ ***dissolved*** in crude oil, condensate, or produced water under pressure is released when the liquids are subject to a decrease in pressure."
2. §95667(29). The definition for "natural gas" states "Natural gas may be field quality (which varies widely) or pipeline quality." "Pipeline quality natural gas" is not defined in the proposed rule while there is no mention of "Commercial quality natural gas" as defined in §95667(10).
3. §95667(30). For the definition of "Natural gas gathering and boosting station" we suggest the following change: "Natural gas gathering and boosting station means all equipment and components located within a facility fence line associated with moving natural gas ***from production fields*** to a processing plant or natural gas transmission pipeline."
4. §95667(46). The definition of "Pressure separator" should be consistent with the definition of "Separator."
5. §95667(46). For the definition of "Separator" we suggest the following change: "Separator" means any tank or pressure separator used for the primary purpose of separating crude oil***, natural gas*** and***/or*** produced water or for separating natural gas, condensate, and***/or*** produced water. In crude oil production a separator may be referred to as a Wash Tank or as a three-phase separator. In natural gas production fields, a separator may be referred to as a heater/separator."
6. §95667(61). For the definition of "Vapor control efficiency" we suggest the following change: "Vapor control efficiency" means the ability of a vapor control device to control emissions, expressed as a percentage, which can be estimated by calculation or by measuring the total hydrocarbon ~~concentration~~ ***mass flow rate*** at the inlet and outlet of the vapor control device."
7. §95668(d)(2)(A) & (e)(2)(A) allows an exemption for compressors with use of less than 200 hours per year. However, the current rule language limits the exemption to natural gas powered compressors. We suggest the following change to include electric driven natural gas compressors.
   - "Reciprocating natural gas ~~powered~~ compressors that operate…."
   - "Centrifugal natural gas ~~powered~~ compressors that operate…."
8. We believe the intent is to apply these requirements to stationary compressors similar to the existing GHG MRR (40 CFR, Part 98, Subpart W). For clarity, we suggest the following change.
   - 95668(d)(1): "Except as provided in section 95668(d)(2), the following requirements apply to ***stationary*** reciprocating natural gas compressors located at facilities listed in section 95666."
   - 95668(e)(1): "Except as provided in section 95668(e)(2), the following requirements apply to ***stationary*** centrifugal natural gas compressors located at facilities listed in section 95666."
9. §95669(b) LDAR
   - We request an exemption be added for components that do not contain methane. Proposed language from the GHG MRR section 95153(o) "***Component types in streams with gas content less than 10 percent CH4 plus CO2 by weight***"

10. §95669 (b)(7) for clarity we suggest the following change
"One-half inch and smaller stainless steel tube fittings used to supply natural gas to equipment or instrumentation that have been tested using US EPA Method 21 and reported to be below the minimum allowable leak threshold ***during the first quarterly survey performed after their installation date.***"

**<u>Comments on Proposed Rule Standards</u>**

**11. ARB has not demonstrated existing control technologies for compliance with the proposed rule requirements for reciprocating compressor rod packing vent stacks (i.e., 95% vapor control efficiency, $NO_x$ < 15 ppmv at 3% $O_2$, and no supplemental fuel gas in accordance with §95668(d)(4)(C) and §95668(c)(4)(B)), and the rule requirements should be revised to comport with the operational requirements of available external combustion equipment (e.g., use of supplemental fuel and/or achievable NOx limits).**

§95668(d)(4)(C) provides an option for rule compliance for reciprocating compressors, and requires that gas emissions from compressor vent stacks used to vent rod packing or seal emissions be controlled with the use of a vapor collection system as specified in section 95668(c). This option is not always viable and, therefore, the rule should be revised to consider the operational requirements of available external combustion equipment used to control emissions. This control requirement would be the only viable option for compressors where the captured emissions have the potential for entrained air (e.g., from a reciprocating compressor distance piece into which rod packing vents) and cannot be compressed into an existing sales gas or fuel gas system due to safety considerations. §95668(c)(4)(B) states:

> "If the vapor control device is to be installed in a region classified as non-attainment with, or which has not been classified as in attainment of, all state and federal ambient air quality standards, the owner or operator must install one of the following devices that meets all applicable federal, state, and local air district requirements:
>
> 1. A non-destructive vapor control device that achieves at least 95% vapor control efficiency of total emissions and does not result in emissions of nitrogen oxides (NOx); or,
>
> 2. A vapor control device that achieves at least 95% vapor control efficiency of total emissions and does not generate more than 15 parts per million volume (ppmv) NOx when measured at 3% oxygen and does not require the use of supplemental fuel gas, other than gas required for a pilot burner, to operate."

ARB documents list Aereon Corporation as a provider of certified burners that meet this NOx limit; however, the smallest thermal capacity for the Aereon burners is 0.17 MMBtu/hr, or 170 scf/hr for 1,000 Btu/scf natural gas as shown in Table 1[1]. Reciprocating compressor rod packing leak rates greater than 2 scfm / 120 scf/hr require control, and a 120 scf/hr leak would require supplemental fuel to use the ARB-selected Aereon burners for emissions control. Further, rod packing does not leak at a steady rate – e.g., depends on compressor mode (i.e., operating or not-operating) and gas pressure and temperature – and the combustion control device would require supplemental fuel to

[1] Certified Low-NOx burner specifications provided by Phanindra Kondagari, Senior Process Engineer at Aereon Corporation on June 27, 2016.

assure proper air fuel ratio and low-NOx operation. All of SoCalGas’s existing thermal oxidizers use supplemental fuel, which is critical to achieving low NOx, particularly to control a variable flow of leaked gas that may or may not include entrained air. However, supplemental fuel gas is not allowed by the proposed rule. Thus, the ARB selected burners are not a viable control option. In sum, ARB has not demonstrated existing control technologies for compliance with the proposed rule requirements (i.e., 95% vapor control efficiency, $NO_x$ < 15 ppmv at 3% $O_2$, and no supplemental fuel gas), and the rule requirements should be revised to comport with the operational requirements of available external combustion equipment (e.g., use of supplemental fuel and/or achievable NOx limits).

**Table 1 Specifications for Aereon Corporation Certified Ultra-Low Emission Burners**

| Product | Max. Capacity (MMBtuH) | Min. Capacity ( MMBtuH) |
|---|---|---|
| CEB-50 | 1.7 | 0.17 |
| CEB-100 | 3.4 | 0.34 |
| CEB-350 | 12.0 | 1.2 |
| CEB-500 | 17.0 | 1.7 |
| CEB-800 | 27 | 2.7 |
| CEB-1200 | 40 | 4.0 |

**12. §95668(e)(3) and §95669(b) should be revised to clarify that the <u>dry seals</u> on centrifugal compressors are not subject to the Leak Detection and Repair requirements of §95669.**

Dry seals reduce emissions of high pressure gas from the compressor case along rotating shaft, but they leak slightly by design and do not completely eliminate the gas leak. Dry seal leak rate data from many sources show “normal” process emissions that could result in Method 21 leak concentration measurements exceeding the leak thresholds in §95669(h) and §95669 (i) (i.e., 10,000 and 1,000 ppmv as methane).

- Data compiled by Bylin et al[2] estimated that centrifugal compressor dry seal leak rates range from 0.5 to 3 scfm.
- Based on US EPA Natural Gas STAR recommended technologies and practices, ARB staff determined that 3 scfm is the average emission rate for a dry seal.[3]
- Gas turbine dry seal leak data produced by Solar Turbines estimates leak rates ranging from about 1 to 20 scfm depending on the compressor size, model and suction pressure.[4]

Revisions are needed to clearly indicate that normal process emissions from dry seals are not subject to LDAR requirements.

[2] Bylin, Carey et al. “Methane’s Role in Promoting Sustainable Development in the Oil and Natural Gas Industry”, 24th World Gas Conference, in Buenos Aires, Argentina, October 2009

[3] State of California Air Resources Board, Public Hearing to Consider the Proposed Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, Staff Report: Initial Statement of Reasons, May 31, 2016

[4] Solar Turbines Product Information Letter 251 “Emissions from Centrifugal Compressor Gas Seal Systems”, January 2013

13. §95669(e) should be revised as follows:

> “Owners or operators shall audio-visually inspect (by hearing and by sight) all hatches, pressure-relief valves, well casings, stuffing boxes, and operating pump seals for leaks or indications of leaks at least once every ~~24 hours~~ ***normal business day (i.e., excludes weekends and holidays)*** for facilities that are visited ~~daily~~ ***during each normal business day***, or at least once per calendar week for unmanned facilities;”

**14. ARB does not adequately justify the need for quarterly LDAR in §95669 because it relies on unsubstantiated source material. Historical results from an on-going O&G systems LDAR program that measures leak reductions indicate that annual surveys using a Method 21 gas leak concentration measurement (i.e., screening value) of 10,000 ppmv as a leak definition would result in emission reductions commensurate with or greater than the faulty assumptions used by ARB that are the basis for the proposed rule. A concern with annual LDAR programs is unabated large leaks, and this concern is alleviated by the proposed rule audio-visual inspection requirements that would ensure that large leaks that may develop (e.g., due to component or equipment failure) are discovered and addressed separate from the periodic survey.**

The need for quarterly LDAR is not adequately justified because it relies on unsubstantiated source material. As discussed below, annual surveys using a Method 21 gas leak concentration measurement (i.e., screening value) of 10,000 ppmv or more as a leak definition would result in emission reductions commensurate with or greater than the faulty assumptions used by ARB that are the basis for the proposed rule. §95669(g) requires that all components shall be tested for leaks of total hydrocarbons at least once each calendar quarter. Information provided by ARB in Appendix B: Economic Analysis indicates that ARB believes quarterly monitoring will result in a 60% reduction in gas leak emissions.

> “According to the ICF Report, a quarterly inspection program is expected to reduce emissions by 60%.”

However, (1) this 60% reduction estimate appears to be an unfounded “circular reference” and there is no evidence that it is supported by actual measurement data; and (2) more reliable historical data from implementation of a multi-year O&G systems directed inspection and maintenance (DI&M) program (i.e., repair larger leaks and those that are cost effective to repair) indicates about 75 - 80% reduction is achieved using *annual* monitoring.

(1) <u>The 60% reduction estimate appears to be based on a “circular” and unfounded reference and there is no evidence that it is supported by actual measurement data.</u>

The pertinent text is from page 3-10 of the ICF 2014 Report:[5]

> “Research cited by both Colorado and EPA indicates that more frequent inspections result in greater reductions, summarized as approximately:
>
> - Annual inspection = 40% reduction
> - Quarterly inspection = 60% reduction

[5] “Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries,” ICF International, March 2014

- Monthly inspection = 80% reduction"

These emission reduction data are not supported and highly questionable. Observations which make these data suspect include:

- In the Background Technical Support Document (TSD) for the Proposed Rule for Subpart OOOOa "Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015" of 40 CFR 60[6], EPA referenced a Colorado Air Quality Control Commission (CAQCC) Economic Impact Analysis report for Regulation 7 to support the emission reductions expected from an OGI monitoring program:

    "Based on this range of expected emission reductions as characterized by Colorado's Economic Impact Analysis, it is expected that an OGI monitoring program in combination with a repair program can reduce fugitive $CH_4$ and VOC emissions from these segments by 40 percent on an annual frequency, 60 percent on a semiannual frequency and 80 percent on a quarterly frequency"

- However, the CAQCC report[7] references an unspecified EPA source for these reduction efficiencies:

    "Based on EPA reported information, the Division calculated a 40% reduction for annual inspections, a 60% reduction for quarterly inspections, and an 80% reduction for monthly inspections."

  Neither EPA nor CAQCC provided data or rationale to support the assumed emission reduction efficiencies, and EPA changed the reduction efficiencies from CAQCC without explanation or further justification (i.e., an alternative, legitimate citation was not provided). Thus, there is no evidence in the referenced documents that these reduction efficiencies are based on actual measurements, and they appear to be based on circular references that were accepted by these regulatory agencies without verification or supporting data.

(2) More reliable historical data from implementation of an O&G systems DI&M program indicates about 75 - 80% reduction is achieved using annual monitoring.

A Canadian Association of Petroleum Producers (CAPP) 2014 document "Update of Fugitive Equipment Leak Emission Factors"[8] estimates that upstream oil and gas equipment leak emissions have decreased about 75% since DI&M best management practices (BMP)[9] were implemented (2007 and later). For the CAPP leak emission factors document and the BMP, an equipment component is generally deemed to be leaking if it produces a screening value of 10,000 ppm or

[6] EPA-HQ-OAR-2010-0505-5120. Background Technical Support Document for the Proposed New Source Performance Standards 40 CFR 60, subpart OOOOa, August 2015.

[7] EPA-HQ-OAR-2015-0216-0032. Colorado Air Quality Control Commission, *Initial Economic Impact Analysis for Proposed Revisions to Regulation Number 7 (5 CCR 1001-9).* November 15, 2013.

[8] EPA-HQ-OAR-2010-0505-4826. "Update of Fugitive Equipment Leak Emission Factors", Canadian Association of Petroleum Producers (CAPP), February 2014.

[9] "Management of Fugitive Emissions at Upstream Oil and Gas Facilities", Canadian Association of Petroleum Producers (CAPP), January 2007.

greater when screened in accordance with Method 21, or the emissions are detectable by a leak imaging infrared camera.

The BMP does not specify a leak detection survey frequency:

> "Operators should develop a DI&M survey schedule that achieves maximum cost-effective fugitive emissions reductions yet also suits the unique characteristics and operations of their facility."

However, the BMP does provide leak detection survey frequency guidance for various "leak-prone" equipment components. Annual surveys are listed for control valves, block valves, emergency vents, pressure relief valves (PRVs), and open-ended lines (OELs). Quarterly surveys are listed for compressor seals, pump seals, blowdown systems, and hatches and pressure-vacuum safety valves on tanks. Compressor seals are covered separately (i.e., not by the LDAR requirements) in the proposed ARB rule. Other components that are less "leak-prone", such as flanges and connectors, would likely be surveyed annually (i.e., with the valves, PRVs, and OELs) or less frequently. Lacking actual data regarding the leak survey frequencies, a reasonable assumption would be that the majority of equipment components associated with the 75% emissions reduction was surveyed annually. This performance metric documented in a report and based on actual data indicates that an annual survey can achieve better performance than ARB hypothesizes for quarterly surveys. Thus, an annual survey frequency using a leak definition based on a Method 21 screening value of 10,000 ppmv is adequate.

This estimate of 75% reduction in leak emissions from oil and gas operations from annual monitoring is based on directly measured and estimated (e.g., from Method 21 screening values and associated emission factors) leak emissions encompassing multiple years using a DI&M approach, and was the most reliable and best supported estimate of LDAR emissions reductions found in the literature. LDAR programs, which require repair of all leaks (i.e., more leak repairs and nominally more reductions compared to a DI&M program), would be expected to have marginally higher reductions. Based on this CAPP data, 80% would appear to be a reasonable estimate of the control efficiency for an LDAR program with annual monitoring (albeit at a higher cost than DI&M). LDAR "summary papers" in the literature that conclude "all leaks" can be easily or economically repaired are essentially position papers that are ill-founded and based on erroneous assumptions. The discussion above is documented from the CAPP study and based on real, multi-year data from a leak mitigation program.

Measurement data comparing leak reduction efficiencies for LDAR or DI&M programs with various leak monitoring frequencies were not found, but performance improvements with more frequent surveys can be estimated. Leak reduction efficiencies for various typical leak monitoring frequencies can be estimated by assuming: (1) a linear leak rate growth with time; (2) that all detected leaks are repaired; and (3) a leak emissions reduction efficiency of 80% for annual monitoring. This implies, semiannual monitoring would incrementally reduce the annual monitoring emissions by half, for an overall annual control efficiency of 90% (incremental increase of 10% relative to annual monitoring). Similarly, quarterly monitoring would incrementally reduce the semiannual monitoring emissions by half, for an overall annual control efficiency of 95% (incremental increase of 5% relative to semiannual monitoring). Considering leaks that are unsafe to measure and delay of repair provisions for critical components, a quarterly monitoring emission reduction estimate of 90% may be more realistic. And, assuming a linear growth in leak rates likely over-estimates the incremental benefit from increased survey frequency. A concern with annual

LDAR programs is unabated large leaks, and this concern is alleviated by the proposed rule audio-visual inspection requirements that would ensure that large leaks that may develop (e.g., due to component or equipment failure) are discovered and addressed separate from the periodic survey.

This analysis is consistent with leak survey monitoring frequency/reduction efficiency correlations estimated from data from the EPA Equipment Leaks Protocol document. These estimates show small incremental increases in leak emission reductions with more frequent monitoring, and indicate greatly diminished returns for leak monitoring more frequent than annual.

**15. EPA Method 21 gas leak concentration measurements (i.e., screening values) have a very large uncertainty, are extremely poor predictors of gas leak rates, define a minimum leak definition concentration of 4,000 ppmv for many detectors, and should not be the basis for leak repair thresholds and schedules, and rule compliance determinations. The Proposed Rule's LDAR provision should consider (1) the limitations of Method 21 and (2) that over 98% of gas leak mass emissions are from leaks from components with Method 21 screening values greater than or equal to 10,000 ppmv, and adopt a leak definition of Method 21 gas leak concentration measurement of 10,000 ppmv (as discussed in Comment 14) and remove Method 21 measured concentration-based rule requirements [e.g., §95669(h), (i), and (o)].**

Method 21 Limitations

§95669(g) requires that all components shall be tested for leaks of total hydrocarbons at least once each calendar quarter using EPA Method 21 with the detector calibrated with methane or an Optical Gas Imaging (OGI) instrument. The Allowable Number of Leaks (Table 1 and Table 3) and the Repair Time Periods (Table 2 and Table 4) are based on leak concentrations measured using Method 21. Method 21 leak concentration measurements (i.e., screening values) have a very large uncertainty, are extremely poor predictors of actual volumetric and mass leak rates, and should not be the basis for the Allowable Number of Leaks, Repair Time Periods, or other rule requirements (e.g., §95669(o)). The following data and discussion strongly support this assertion.

- Figure 1 shows Gas Research Institute (GRI) data of measured gas leak rates at transmission sector sources as a function of Method 21 screening values, and shows that mass emission rates associated with a Method 21 leak concentration measurement can vary by 3 to 4 orders of magnitude. For example, for a Method 21 leak concentration measurement of about 10,000 ppmv, the measured mass emission rates ranged from less than 0.001 lb/hr to more than 1 lb/hr, a difference greater than three orders of magnitude. A similar range is observed at 1,000 ppmv, the other Method 21 leak concentration measurement threshold in the proposed rule.

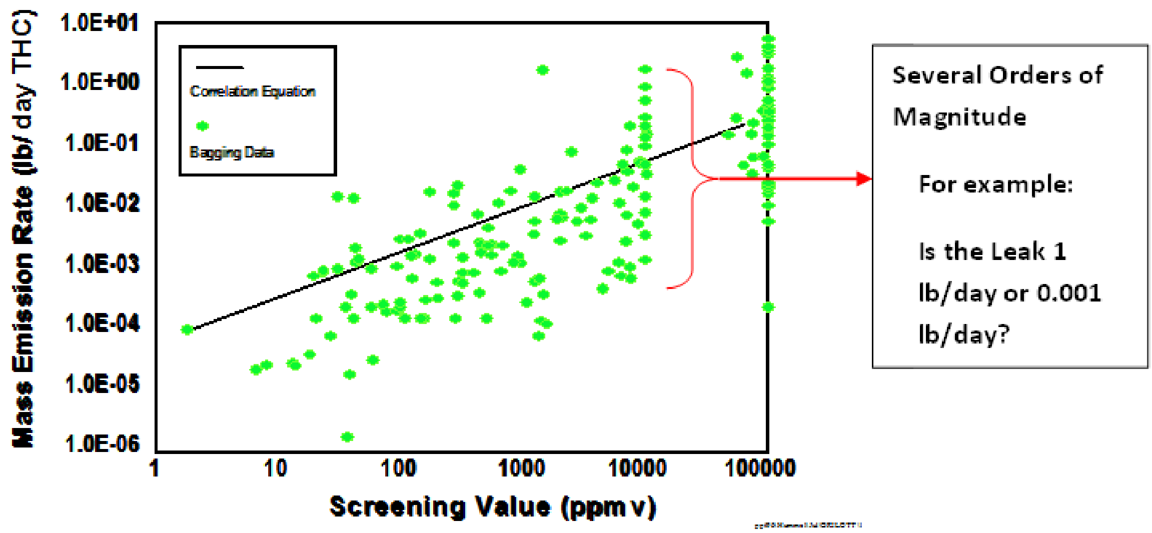


Figure 1. Leak rate versus concentration and correlation equation estimate.

- Similar scatter is observed in Method 21 leak concentration vs. measured leak rate data compiled by EPA to develop the EPA Protocol for Leak Emission Estimates (e.g., refer to Figures C-1 and C-2)[10].
- These disparate mass emissions data are consistent with the qualification provided in Section 2.0 of Method 21:

  “This method is intended to locate and classify leaks only, and is ***not*** [***emphasis added***] to be used as a direct measure of mass emission rate from individual sources.”

  This qualification indicates that it is not appropriate to solely base compliance requirements on Method 21 leak concentration measurements, rather Method 21 leak concentration measurements should be more appropriately used as a screening tool to identify leaks for which quantitative measurements or other judgement regarding leak size should be applied.
- Section 6.4 of Method 21 specifies that the sample flow rate during leak concentration measurements shall be 0.10 to 3.0 l/min; thus, there is a factor of 30 difference between the lowest and highest allowable flowrates. Consequently, two different Method 21 leak detection instruments, operating at the low end and high end of the allowable flow rate range, would measure sample leak concentrations that differ by a factor of about 30.
- Section 6.3 of Method 21 specifies that “The scale of the instrument meter shall be readable to ±2.5 percent of the specified leak definition concentration.” §95669(i) defines a leak to be a Method 21 measured concentration greater than or equal to 1,000 ppmv (as methane), and 2.5% of this value would be 25 ppmv or 0.0025%. Many commercially available gas detectors for methane have a detection limit of 0.01%, and would not meet the Method 21 specifications for measuring 1,000 ppmv leaks. The associated leak definition concentration would be 4,000 ppmv. Even though lower leak thresholds are in place in some jurisdictions (e.g., 500 ppmv for VOC rules that may utilize other detectors), it is not clear that ARB has identified leak detection

[10] EPA Protocol for Leak Emission Estimates, EPA-453/R-95-017, November, 1995.

equipment that can be used to demonstrate compliance with the 1,000 ppmv leak standard. To ensure accurate concentration measurements by leak detection instruments, the rule should clearly state that Method 21 leak detection instruments must comply with the requirements of Section 6.3.

- Many Method 21 instruments have two detectors for accurate concentration measurements from 0 – 100%. For example, a low range (0 – 5%) catalytic detector and a high range (5 – 100%) thermal conductivity detector. A consequence of the two detectors is that measurement of concentrations near 5% (e.g., 4% - 6%) are very uncertain because it appears the instrument electronics can oscillate between the two detectors, and the instrument may get stuck on a 5% output. Thus, a 5% Method 21 leak concentration as an actionable threshold should be avoided due to the high uncertainty associated with these readings.

- Section 7.1.2 of Method 21 provides a Calibration Gas specification:

  > "For each organic species that is to be measured during individual source surveys, obtain or prepare a known standard in air at a concentration approximately equal to the applicable leak definition specified in the regulation."

  Some leak surveyors calibrate leak detectors with zero gas and 100% methane gas, and this calibration procedure would not be appropriate for leak definitions of 1,000 ppmv or 10,000 ppmv. To ensure accurate concentration measurements by leak detection instruments, the rule should clearly state that Method 21 leak detection instruments must be calibrated in accordance with Section 7.1.2 for the appropriate leak definition.

- The response of Method 21 instruments varies for different gas species (e.g., methane, ethane, propane), and the responses of the two detectors (i.e., catalytic detector and thermal conductivity detector) will differ for the same gas specie. Thus, variations in leaking gas stream compositions contribute to the uncertainty of Method 21 leak concentration measurements and the extremely poor leak concentration / leak rate correlation.

- Section 8.3.1 of Method 21 provides general guidance for measurement of leak concentrations and generally requires placing the probe at the surface of the component interface where leakage could occur and moving the probe along the interface to find a maximum reading. The measured leak concentration will be impacted by the fraction of the leaking gas that is captured and the amount of sample dilution air. The dilution air rate will be impacted by the accessibility of the leak (e.g., impacted by the leak interface geometry), the angle of the probe opening (i.e., is sample air flow obstructed), and, as discussed above, the baseline instrument sample rate which can vary by a factor of 30.

  Table 2 summarizes Method 21 guidance for measuring leaks from different component types and discusses how component configuration can impact the leak measurement.

**Table 2. Method 21 Leak Location Guidance for Various Components.**

| Component | Summary of M21 Leak Location Guidance (Section 8.3.1) | Notes |
|---|---|---|
| Valves | Most common source of leaks is the seal between the stem and housing<br>- Also survey the interface of the packing gland take-up flange seat and the valve housings of a multipart assembly at interface surfaces where leaks could occur | Some interfaces and surfaces are difficult to access and can preclude complete leak capture |
| Flanges | Survey circumference of flange | - It can be difficult to isolate leaks on a flange circumference |
| Pumps and Compressors | Circumferential traverse at the outer surface of the pump or compressor shaft and seal interface. Position the probe within 1 cm of rotating shaft-seal interfaces. Housing configuration may prevent a complete shaft periphery traverse. Survey all housing joints and other leakage locations. | - Moving parts and inaccessible interfaces can preclude complete leak capture |
| Pressure Relief Devices (PRDs) | The configuration of most PRDs prevents sampling at the sealing seat interface. For PRDs equipped with an enclosed extension, or horn, place the probe near the center of the exhaust area to the atmosphere. | - Probes sampling near the center of an opening rather than the leak interface may not capture the entire leak<br>- For components such as OELs or PRD's with an extension / vent line, slowly leaking gas will completely fill the vent line tubing or piping. M21 samples that pull sample from the end of the extension will measure this residual gas and can over-estimate the leak concentration |
| Process Drains | For open drains, place the probe inlet near the center of the area open to the atmosphere.<br>For covered drains, place the probe at the surface of the cover interface and conduct a peripheral traverse. | |
| Open-ended Lines or Valves | Place the probe inlet near the center of the opening to the atmosphere | |
| Seal System Degassing Vents and Accumulator Vents | Place the probe inlet near the center of the opening to the atmosphere | |
| Access door seals | Place the probe inlet at the surface of the door seal interface and conduct a peripheral traverse | - The Method 21 sample can pull gas that has accumulated inside the access door and this will not be representative of the leak rate occurring inside the access door (i.e., high bias to M21 leak concentration measurement) |

Based on the information provided in Table 2, it is evident that different biases in Method 21 concentration measurements can exist for different component types, and that a single Method 21 concentration leak threshold should not apply for all types of components.

<u>Over 98% of Gas Leak Mass Emissions are from Leaks from Components with Method 21 Screening Values Greater Than or Equal to 10,000 ppmv</u>

A review of the methane mass emission estimates from California oil and gas components in Table B-9 in the CARB EA shows that over 98% of the emissions are from leaks from components with Method 21 screening values greater than or equal to 10,000 ppmv. This indicates a less than 2% incremental increase in emission reductions for a leak definition of Method 21 gas leak concentration measurement of 1,000 ppmv versus 10,000 ppmv. These emissions (and potential reductions from LDAR) are based on emission factors from a 1999 CAPCOA document[11] which are listed in Table 3. The fourth column shows the ratio of the greater than / less than 10,000 ppmv emission factors, and the greater than 10,000 ppmv emission factors are generally three orders of magnitude larger than the less than 10,000 ppmv emission factors

**Table 3. CAPCOA O&G Components Leak Rate Emission Factors (Table IV-2c)**

| Component Type | (kgTHC/hr/source) | | Ratio (> / <) |
|---|---|---|---|
| | Components > 10,000 ppm | Components < 10,000 ppm | |
| Valves | 1.39E-01 | 3.50E-05 | 3,971 |
| Connectors | 2.59E-02 | 1.20E-05 | 2,158 |
| Flanges | 6.10E-02 | 2.80E-05 | 2,179 |
| Open end lines | 5.49E-02 | 2.40E-05 | 2,288 |
| Pump Seals | 8.90E-02 | 9.96E-04 | 89 |
| Others (compressors, hatches, etc.) | 1.38E-01 | 1.47E-04 | 939 |

These emission factors are supported by same component emission factors for the oil and gas industry from the EPA Protocol for Leak Emission Estimates and shown in Table 4. Note the similar greater than / less than 10,000 ppmv emission factors ratios in the fourth column.

**Table 3. EPA Leak Protocol O&G Components Leak Rate Emission Factors (Table 2-8,)**

| Component Type | (kgTOC/hr/source) | | Ratio (> / <) |
|---|---|---|---|
| | Components > 10,000 ppm | Components < 10,000 ppm | |
| Valves | 9.80E-02 | 2.50E-05 | 3,920 |
| Connectors | 2.60E-02 | 1.00E-05 | 2,600 |
| Flanges | 8.20E-02 | 5.70E-06 | 14,386 |
| Open end lines | 5.50E-02 | 1.50E-05 | 3,667 |
| Pump Seals | 7.40E-02 | 3.50E-04 | 211 |
| Others (compressors, hatches, etc.) | 8.90E-02 | 1.20E-04 | 742 |

Thus, it is clear that the vast majority of O&G leak emissions are from components with Method 21 screening values greater than or equal to 10,000 ppmv, and the incremental emission reductions associated with a lower screening value leak definition (e.g., 1,000 ppmv) would be very small.

CARB has not provided cost-effectiveness (i.e., $/metric ton emissions reduction) calculations for the 1,000 ppmv screening value leak definition and the 10,000 ppmv screening value leak definition, or the cost-effectiveness of the incremental emission reductions for a 1,000, rather than 10,000, screening

[11] CAPCOA, ARB. 1999. The California Air Resources Board Staff California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities.

value leak definition. Considering the much lower leak rates (on average) for components with Method 21 screening values less than 10,000 ppmv, it would be expected that the cost to repair these leaks would be prohibitively high (i.e., very high $/incremental mt of emissions reduction).

Conclusion

For the reasons discussed above, it is clear that the same gas leak measured by different personnel and equipment could have very different Method 21 concentrations, and that the leak rate associated with a Method 21 concentration measurement has a very high uncertainty. This is reflected in the wide spread in the leak rate / leak concentration data presented in Figure 1 and the referenced figures in the EPA Protocol for Leak Emission Estimates. Method 21 gas leak concentration measurements are not an appropriate metric on which to characterize leak rates, determine thresholds for component repair period requirements, or to determine compliance with LDAR requirements. , In conclusion, the ARB rule LDAR provision should consider the limitations of Method 21, the incremental cost-ineffectiveness of a 1,000 ppmv Method 21 screening value, and the documented leak mitigation performance objectives discussed in Comment 14, and adopt a leak definition of Method 21 gas leak concentration measurement of 10,000 ppmv and remove Method 21 measured concentration-based rule requirements [e.g., §95669(h), (i), and (o)].

16. **Tagging every critical component as required by §95670 is impractical, not necessary to comply with the intent of the proposed rule, an inefficient use of resources, and presents a safety hazard by obstructing and interfering with operator access to equipment, and as a potential fire hazard. If critical component tagging is included in the rule, it should be limited to a tag on the last critical component on each inlet and outlet stream (e.g., pipe or tubing) to the critical process unit. These tags would clearly demark the boundaries of the critical process unit and critical components, and would not require a multitude of tags all over industrial process equipment.**

    §95670 requires that owners or operators maintain "a record of ***all*** [***emphasis added***] critical components at the facility", and that "***each*** [***emphasis added***] critical component must be identified using a weatherproof, readily visible tag."

    Tagging ***each*** critical component is not practical, not necessary to comply with the intent of the proposed rule, and an inefficient use of resources. Further, tagging every component presents a safety hazard by obstructing and interfering with operator access to equipment, and could present a fire hazard. For example, if every component (e.g., connector, etc.) requires a tag for a critical gas-fired engine and associated reciprocating compressor, there would be hundreds of tags in the vicinity of hot surfaces and moving parts. The tags could pose an additional safety issue by being an unnecessary distraction for operators working in potentially hazardous conditions (e.g., during major repair operations). If critical component tagging is included in the rule, it should be limited to a tag on the last critical component on each inlet and outlet stream (e.g., pipe or tubing) to the critical process unit. These tags would clearly demark the boundaries of the critical process unit and critical components, and would not require a multitude of tags all over industrial process equipment.

    Maintaining a record of ***all*** critical components is not practical, not necessary to comply with the intent of the proposed rule, and an inefficient use of resources. Recordkeeping should be limited to include each critical process unit and a list of the associated tagged critical components demarking the boundaries of the critical process unit.

Table A3 in Appendix A should be modified accordingly.

17. **Table 2 and Table 4 should be revised to indicate up to 12 months is allowed for repair of critical components, which is consistent with the time allowed in §95669(h)(3) and (i)(4).**

For LDAR, §95669(h)(3) and (i)(4) specify the maximum time allowed for repair of critical components, and up to 12 months is allowed. This is a revision from earlier versions of the Proposed Rule that indicated 180 days, and SoCalGas supports the longer timeframe. However, ARB omitted analogous revisions required in Table 2 and Table 4. For the "Repair Time Period" indicated in Tables 2 and 4, the line item for critical components should be revised to, "Next shutdown or within ~~180 calendar days~~**12 months**."

**18. Natural gas utilities under the jurisdiction of the CPUC should not be required to receive approval by the ARB Executive Officer or other entities for their critical process units and associated critical components. Utilities should be allowed to submit documentation showing the processes that will utilize the critical component exemptions to maintain a safe and reliable natural gas system.**

Under the jurisdiction of the California Public Utilities Commission (CPUC), both SoCalGas and SDG&E are providers of an Essential Public Service. The primary functions are intrastate natural gas transport and to "withdraw" previously stored gas to meet customer needs. As such, natural gas underground storage and transmission station operations are vital to the utility's ability to reliably supply the markets at times of varying demand.

The Proposed Rule requires identification, documentation, and pre-approval of critical components in order to extend repair timeframes. This may result in a conflict between complying with the regulations governing a public utility and this regulation. ARB should seek to balance critical operational, cost and safety demands with timely leak repair activities.

As an example of this need for balance, excerpts from SB1371 (Leno) Natural Gas Leakage Abatement contain language that address both environmental needs with and operational and safety concerns:

***SECTION 1***

*"The Legislature finds and declares all of the following: (a) The Legislature has established that safety of the natural gas pipeline infrastructure in California is a priority for the Public Utilities Commission and gas corporations, and nothing in this article shall compromise or deprioritize safety as a top consideration."*

*Article 3. Methane Leakage Abatement*

*"(b) With priority given to safety, reliability, and affordability of service, the commission shall adopt rules and procedures governing the operation, maintenance, repair, and replacement of those commission-regulated gas pipeline facilities…"*

We believe that allowing public utilities to manage their systems that determine what are critical processes will balance the need for safe and reliable gas delivery to our customers with the necessity to further reduce methane emissions.

Therefore, we suggest the following change:

§95670

(a)(1)

**Natural gas utilities are not required to receive approval by the ARB Executive Officer or other entities for their critical process units and associated critical components. Utilities must submit documentation showing the processes that will utilize the critical component exemptions to maintain a safe and reliable natural gas system. Natural gas utilities are exempt from the remainder of this section.**

**Attachment D: Proposed Regulation Wells Applicability**

**For Storage Wells, ARB Should Clearly Indicate that Standards in §95668(b) for Circulation Tanks and §95668(g) for Liquids Unloading Do Not Apply. Applicability of §95668(h) for Well Casing Vent Measurement Should Also Be Clarified.**

The Proposed Regulation frequently refers to "well" related requirements without clearly indicating whether the applicable source is production wells, storage wells, or both. As currently drafted, definitions, other rule requirements, background materials, and other cited documents need to be reviewed to determine applicability. ARB should improve clarity by revising the Proposed Regulation to refer to the specific well type. For example, the definition of "Well" in §95667(a)(67) broadly includes production wells and underground storage wells, so additional review is needed to determine applicability or exclusions for storage wells. As explained below, review of the Proposed Regulation indicates that §95668(b) and (g) standards do **not** apply to storage wells. It appears that well casing vent measurement requirements in §95668(h) may apply to storage wells. However, the Proposed Regulation should be revised for all three of these standards to more clearly indicate applicability and avoid confusion when the rule is implemented.

§95668(b) – Circulation Tanks for Well Stimulation Treatments

For storage wells, applicability of §95668(b) is not immediately evident. Based on the following, SoCalGas concludes that this standard does not apply to storage wells:

- "Well stimulation treatment" traditionally refers to processes to improve gas flow from *production* wells, and a definition is included at §95667(a)(65).

  > "Well stimulation treatment" means the treatment of a well designed to enhance crude oil and natural gas production or recovery by increasing the permeability of the formation and as further defined by the Division of Oil, Gas, and Geothermal Resources SB 4 Well Stimulation Treatment Regulations, Chapter 4, Subchapter 2, Article 2, section 1761(a) (December 30, 2014)."

  The description refers to natural gas *production*, and storage wells are not mentioned. However, excluding storage wells based solely on the definition is not obvious. For example, storage well clean out and maintenance is conducted, and the proposed definition does not clearly exclude those activities.

- The well stimulation definition refers to DOGGR regulations,[1] which provide additional insight.

- The DOGGR rule Final Statement of Reasons[2] indicates, "Public Resources Code section 3157 defines the term 'well stimulation treatment'…," and notes the intent to clarify whether specific types of operations do or do not meet the definition. The definition in PRC Section 3157(a) and (b) follows:

  > "(a) For purposes of this article, "well stimulation treatment" means any treatment of a well designed to enhance oil and gas production or recovery by increasing the permeability of the formation. Well stimulation treatments include, but are not limited to, hydraulic fracturing treatments and acid well stimulation treatments.

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[1] Division of Oil, Gas, and Geothermal Resources SB 4 Well Stimulation Treatment Regulations, Chapter 4, Subchapter 2, Article 2, section 1761(a) (December 30, 2014).

[2] SB 4Well Stimulation Treatment Regulations, Final Statement of Reasons (December 2014).

> (b) Well stimulation treatments do not include steam flooding, water flooding, or cyclic steaming and do not include routine well cleanout work, routine well maintenance, routine removal of formation damage due to drilling, bottom hole pressure surveys, or routine activities that do not affect the integrity of the well or the formation."

- Because they are excluded in section (b), well maintenance and cleanout to maintain the integrity of underground storage wells do not meet the definition of "well stimulation treatment." Thus, SoCalGas concludes §95668(b) is not applicable to storage wells. For clarity, this should be indicated in the Proposed Regulation by revising the section's title to "Circulation Tanks for **Production** Well Stimulation Treatments." Alternatively, the definition at §95667(a)(65) could be revised to clearly indicate that storage wells are excluded.

§95668(g) – Liquids Unloading of Natural Gas Wells

Similarly, applicability of §95668(g) should be clarified for storage wells. The rule text and definitions do not clearly indicate applicability, but ARB support documents indicate that §95668(g) applies to production wells. For example, the Draft Environmental Analysis (at page 23) describes the affected process as production wells:

> "Over time, natural gas wells accumulate liquids that can impede and sometimes halt gas production. When the accumulation of liquid results in the slowing or cessation of gas production, removal of fluids (e.g., liquids unloading) is required in order to maintain production."

The description refers to gas *production* three times, and storage wells are not mentioned. The Staff Report (Initial Statement of Reasons) also includes background, "in plain English," in Section II.B. The background on Liquids Unloading in subsection (1)(b) describes a process for production wells and does not mention storage wells. ARB should clearly indicate that §95668(g) is not applicable to storage wells. The rule could be revised to indicate §95668(g) applies to, "Liquids Unloading of Natural Gas **Production** Wells." Alternatively, the definition of "liquids unloading" at §95667(a)(28) could be revised to clearly indicate that storage wells are excluded.

§95668(h) – Well Casing Vents

Applicability of the standard for well casing vents is less clear than the two sections discussed above. The proposed rule requires operators of wells with a well casing vent open to the atmosphere to measure the natural gas flow rate from the well casing vent annually, retain records, and report to ARB annually. There is not information available within the Proposed Regulation or background documents to ascertain whether storage wells are excluded. Thus, it appears that §95668(h) may apply to storage wells.

Similar to the clarification requested above, ARB should clarify applicability of §95668(h). In addition, the rule should indicate that this vent line is not applicable to LDAR.

**Attachment E: Agency Regulations**

**A. Pending Agency Rulemakings and Proceedings Have the Potential to Substantively Overlap with ARB's Proposed Regulations**

Currently, at least six other agencies have proposed rulemakings, promulgated regulations, or issued advisory opinions regarding GHG emissions from the oil and gas sector. If each agency were to adopt such rules, continuous compliance would become exceptionally difficult for regulated parties. Operations personnel at affected facilities would have to reconcile their monitoring and reporting activities with every aspect of each regulation's many requirements, which at this point appear very unlikely to be wholly consistent. SoCalGas acknowledges and sincerely appreciates that ARB has been coordinating and/or consulting with other agencies during the preparation of their respective regulations, in particular ARB's assurance that DOGGR's storage facility monitoring requirements will not overlap with this proposed rule. SoCalGas urges that ARB continue to work with other agencies with the goal of synching regulatory requirements to the greatest extent feasible. Currently, however, each agency is poised to either implement or phase in its regulations at different times. These substantive and temporal inconsistencies create inefficiencies by requiring affected facility operators to continuously update their practices and compliance procedures.

The current agency actions include:

- **U.S. Environmental Protection Agency Greenhouse Gas Reporting Program.** On January 29, 2016, EPA proposed revisions and additional confidentiality determinations for the petroleum and natural gas systems source category of the GHGRP.[1] In particular, EPA is proposing to add new monitoring methods for detecting leaks from oil and gas equipment for petroleum and natural gas systems consistent with recently adopted new source performance standards (40 CFR 60, Subpart OOOOa, adopted June 3, 2016) for the oil and gas industry. The proposed GHGRP amendments are aimed at allowing facilities to consistently demonstrate compliance with multiple EPA programs. EPA also is proposing to add emission factors for leaking equipment to be used in conjunction with these monitoring methods to calculate and report GHG emissions resulting from equipment leaks. Further, EPA is proposing reporting requirements and confidentiality determinations for nine new or substantively revised data elements. These reporting requirements will be directed at facilities conducting equipment leak surveys. The facilities will begin reporting emissions using a specific leak survey methodology, and will additionally report the number of leaking components, and the average time the components were assumed to be leaking.

- **U.S. Environmental Protection Agency Methane Challenge**. For existing sources, EPA also is implementing a voluntary methane reduction program known as the Methane Challenge program, and EPA announced initial members

[1] *See* 81 Fed. Reg. 4987-5006 (Jan. 29, 2016), available at https://www.gpo.gov/fdsys/pkg/FR-2016-01-29/pdf/2016-01669.pdf.

in March 2016. EPA has sought consistency with the GHGRP to avoid duplicative, conflicting, or confusing requirements for existing reporters. Founding Methane Challenge program participants are committing to incorporate specific "Best Management Practices (BMPs)" over the next 5 years. In comments provided by SoCalGas/SDG&E on the proposed program, it was noted that California facilities will be subject to myriad methane reduction regulations that could possibly undermine the voluntary effort. Potential participants may be reluctant to commit to the program and make investments in equipment, information management systems, recordkeeping, or employee training only to find that state requirements (promulgated sometime later) compel them to employ conflicting reduction measures. Feedback from EPA to our comments indicates that EPA does not intend to inadvertently create a disincentive from voluntary program participation.

- **U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration Advisory Bulletin.** On February 5, 2016, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") published an advisory bulletin directing all owners and operators of natural gas underground storage facilities to check for leaks in wellheads and pipelines, verify that shutoff valves and other safety equipment are in working order, and verify that the pressure used to force gas underground does not exceed the design limits of the underground reservoir or the associated equipment.[2] The bulletin also directs operators to update their emergency plans.

  Congress recently passed the PIPES Act of 2016, which President Obama signed on June 22, 2016. Among other things, the Act includes:

  - **Section 12 – Underground Gas Storage Facilities:** Within two years of passage, requires PHMSA to issue minimum safety standards for underground gas storage facilities. This section also imposes a "user fee" on underground gas storage facilities as needed to implement the safety standards.

  - **Section 16 – PHMSA Authority to Issue Emergency Order if "Imminent Hazard":** To address an imminent hazard, the Secretary may issue an emergency order imposing emergency restrictions, prohibitions, and safety measures without prior notice or an opportunity for a hearing.

  - **Section 31 – Aliso Canyon Task Force:** Codifies an Aliso Canyon task force that will issue a report within 6 months that will: (A) Analyze cause and contributing factors of the Aliso Canyon natural gas leak; (B) Analyze measures taken to stop the natural gas leak; (C) Assess impact of the natural gas leak on (i) health, safety, and the environment, (ii) wholesale

[2] *See* 81 Fed. Reg. 6334-6337 (Feb. 5, 2016), available at http://phmsa.dot.gov/pv_obj_cache/pv_obj_id_C7740235E7B8724D36AA2CF7EBAA18CAFC110300/filename/2016-02228.pdf.

and retail electricity prices, and (iii) the reliability of the bulk-power system; (D) Recommend how to improve (i) the response to a future leak, and (ii) coordination between all appropriate agencies; (E) Analyze potential for a similar natural gas leak to occur at other underground natural gas storage facilities in the United States; (F) Recommend how to prevent any future natural gas leaks; and (G) Recommend standards for Aliso Canyon and other facilities located in close proximity to residential populations.[3]

- **Senate Bill 1371.** In January 2015, the CPUC adopted an order instituting rulemaking ("OIR") to reduce natural gas leakage consistent with Senate Bill ("SB") 1371.[4] SB 1371 requires the adoption of rules and procedures, in consultation with ARB, to minimize natural gas leakage from CPUC-regulated natural gas pipeline facilities. SB 1371 also requires gas corporations to file an annual report to the CPUC and ARB about their natural gas leaks and their leak management practices.[5]

  Specifically, in implementing SB 1371, the CPUC must: (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; (3) evaluate the operations, maintenance, and repair practices; (4) establish and require the use of best practices for leak surveys, patrols, leak survey technology, leak prevention, and leak reduction; (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 over time; and (6) to the extent feasible, require the calculation of a baseline systemwide leak rate.[6]

  ARB's proposed regulations may potentially overlap with the SB 1371 OIR and ARB's consultative role in that proceeding. As stated by SB 1371,[7] the CPUC and ARB should ensure that the regulations and rules adopted by each agency are consistent. To facilitate such consistency and avoid imposing undue burdens on those subject to both sets of regulations, ARB should delay this rulemaking until the CPUC has completed its rulemaking. By refraining from issuing a rule until the CPUC has completed its process with ARB's consultation, ARB would be reducing regulatory conflict.

- **Division of Oil, Gas, and Geothermal Resources Emergency Regulations.** In January 2016, DOGGR issued emergency regulations concerning natural gas

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[3] PIPES Act of 2016, Section 31, Task Force Report on Leak Cause and Recommendation.

[4] *See* CPUC, Proceeding R-15-01-008, OIR (Jan. 22, 2015).

[5] Cal. Pub. Util. Code § 975.

[6] Cal. Pub. Util. Code § 975(e)(1)-(6).

[7] Cal. Pub. Util. Code § 975(g).

storage facilities.[8] These regulations, which became effective on February 5, 2016, require underground gas storage project operators to submit an inspection and leak detection protocol to DOGGR for review and approval by late February 2016. The protocol must include inspection of wellhead assembly and attached pipelines for each of the wells and the surrounding area within a 100 foot radius of each wellhead. The regulations mandate the use of "effective gas leak detection technology," such as infrared imaging, at least once per day. The emergency regulations require the operator to take into consideration certain factors in deciding which leak detection technology to use, such as "detection limits, remote detection of difficult to access locations, response time, reproducibility, accuracy, data transfer capabilities, distance from source, background lighting conditions, geography, and meteorology."

DOGGR's emergency regulations also require operators of underground gas storage projects to submit a Risk Management Plan to DOGGR for review and approval. These plans must identify potential threats and hazards to reservoir and well integrity, evaluate the risks, identify risk mitigation processes, and establish a process for periodic review of the risk assessment process. Plans must include risk assessment and prevention protocols for: (1) mechanical well integrity; (2) corrosion monitoring and evaluation; (3) monitoring of wells and attendant production facilities for other risks including casing pressure changes, facility flow erosion, hydrate potential, etc.; (4) reservoir integrity demonstration procedures; (5) identification of potential threats and hazards to operation of project; and (6) prioritization of risk mitigation efforts.

In addition, DOGGR requires new monitoring and testing requirements for: annular gas; safety valves; master valves; wellhead pipeline isolation valves; reservoir pressure; and any additional requirements included in the risk management plan adopted.

On July 8, 2016, DOGGR issued Discussion Draft regulations applicable to underground gas storage projects. DOGGR has indicated that these regulations provide an opportunity for public comment prior to the formal rulemaking process, and will be refined into formal draft regulations to be considered through the state's formal process for adopting new regulations. We understand that DOGGR intends to initiate the formal rulemaking process by the end of August 2016 and finalize the rulemaking by early 2017. The Discussion Draft regulations' requirements for operators of underground gas storage projects are very similar to the emergency regulations and suggest that the requirements shall cease to apply if ARB adopts and implements its proposed regulation.

As indicated above, SoCalGas appreciates ARB's efforts to coordinate with DOGGR to avoid regulatory overlap. However, we urge ARB to incorporate into

[8] DOGGR's emergency regulations are available at http://www.conservation.ca.gov/index/Documents/Underground%20Gas%20Storage%20Project%20Requirements%2c%20Text%20of%20Proposed%20Regulations.pdf.

the proposed regulation the flexibility afforded by DOGGR's emergency regulations and Discussion Draft regulations.

- **<u>South Coast Air Quality Management District Order for Abatement (Case No. 137-36): Condition 8 – Enhanced Leak Detection and Reporting Well Inspection Program; Condition 10 – Continuous Air Monitoring Plan; and Condition 11 – Public Notification.</u>** While the Abatement Order is specific to the Aliso Canyon Storage Facility, it nonetheless further demonstrates the extent of regulatory overlap. The Abatement Order requires:

  - SoCalGas to prepare an Enhanced Leak Detection and Reporting Well Inspection Program that provides for:

    - Daily inspections of all active and abandoned natural gas storage wells, water injection wells, and shallow zone oil production wells owned by SoCalGas at Aliso Canyon.

    - Infrared cameras or equivalent to utilize infrared technology to monitor SoCalGas natural gas wells located at the Facility property.

    - Monitoring and emissions measurements during well inspections

    - Prioritizing and conducting an enhanced well leak detection and reporting program based on criteria relevant to the risk of well leakage from the Facility, including maintenance, condition, age and/or emissions from wells.

    - Proactive identification and mitigation (i.e., repair) of potential emissions of air contaminants.

    - Enforceable commitments and timelines to accomplish the specified Program elements as quickly as feasibly possible.

  - SoCalGas to provide the District with funding for District staff or contractor hired by the District, or a combination of the two, to develop, staff, and implement a continuous air monitoring plan, including a methane monitor network at the Facility property, for the nearby school/community during the duration of this Order. This continuous air monitoring plan is "independent from any other air monitoring plan being performed by SoCalGas, or in conjunction with any other agency."

  - An Air Quality Notification Plan providing for public notification of certain types of releases.

  - Various types of recordkeeping (e.g., wells taken out of service or installed, well inspection and maintenance reports, daily infrared camera data).

- **<u>Bureau of Land Management/Department of the Interior Proposed Regulations</u>.** The Bureau of Land Management ("BLM") within the U.S. Department of the Interior ("DOI") is proposing new regulations to reduce waste of natural gas from venting, flaring, and leaks during oil and natural gas production activities on onshore Federal and Indian leases. The proposed rules will require (1) oil and gas producers to adopt currently available technologies, processes and equipment that limits the rate of flaring at oil wells on public and tribal lands, (2) operators to periodically inspect their operations for leaks, and (3) replace outdated equipment that vents large quantities of gas into the air. Operators are also required to limit venting from storage tanks and use best practices to limit gas losses when removing liquids from wells.

### A. Pending Agency Rulemakings Should Be Coordinated in Advance of Implementation

Each of the above-referenced agency actions has its own unique timing for each phase of approval and implementation. We understand the ARB previously anticipated finalizing the regulation as early as September 2016. While the DOGGR emergency regulations were finalized and are being implemented more swiftly, ARB's scheduled finalization date may occur before other agencies are able to finish their rulemaking processes. In any event, ARB and the other agencies identified herein should consider synchronizing the timing to enact proposed regulations to ensure that the regulations are consistent with one another and do not require duplicative actions.

For example, DOGGR's emergency regulations required owners and operators to submit a leak detection and inspection protocol to DOGGR for approval in February. DOGGR's regulations also required owners and operators to start daily monitoring for the presence of annular gas in early March 2016. Owners and operators also were required to do "function testing" on all surface and subsurface safety valve systems in May 2016, and then every six months thereafter. Owners and operators also will be required to test the operation of master valves and wellhead pipeline isolation valves for proper function, and again annually thereafter. Finally, on August 5, 2016, owners and operators must submit a Risk Management Plan to DOGGR. To the extent ARB's regulations ultimately require similar actions at later dates, regulated entities will be forced to conduct duplicative work at a cost that likely exceeds environmental or risk-reduction benefits.

Other pending agency actions may prove instructive and should be fully evaluated by ARB before taking action. For example, EPA published a Notice[9] requesting comment on a proposed Information Collection Request (ICR), which initiates the process for EPA to develop performance standards for *existing* sources in the oil and gas industry. That action will supplement the NSPS (Subpart OOOOa) adopted on June 3. Comments on EPA's proposed rule were due on February 29, 2016. EPA also conducted an information-gathering phase, and requested industry participants to provide data on hazardous air pollutant emissions from the

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[9] 81 FR 35763. EPA Notice, Proposed Information Collection Request; Comment Request; Information Collection Effort for Oil and Gas Facilities (June 3, 2016).

natural gas production, transmission and storage segments of the oil and natural gas sector.[10] The EPA ICR will provide detailed information to assist EPA in its rulemaking process, and EPA envisions the information collection will be completed in March 2017. Therefore, it would be prudent for ARB to more closely assess compatibility with new source regulations (e.g., Subpart OOOOa), and "wait and see" how EPA's existing source requirements will unfold before promulgating potentially duplicative or conflicting regulations. Under §111(d) of the Clean Air Act, EPA envisions the existing source rules will include a larger state role than NSPS, and that programmatic approach will be developed and proposed over the next 12 to 18 months.

Similarly, the CPUC currently is accepting comments on Phase I issues regarding annual reporting requirements, best management practices, and cost-effectiveness considerations to implement SB 1371. The ARB has been actively involved in the CPUC's SB 1371 OIR, including participation in extensive informal workshops and the CPUC's staff proposal issued on January 26, 2016 regarding reporting requirements reflect ARB's recommendations. The CPUC and ARB held a workshop on targets, compliance, and enforcement on April 12, 2016. Issuance of an ARB and CPUC staff proposal on targets, compliance, and enforcement was made on June 23, 2016, and will be followed by a comment period. This process could offer valuable insight and feedback to both the CPUC and ARB, which should be considered in any proposed rules to avoid unnecessary duplication.

The CPUC is expected to issue a Phase I decision regarding SB 1371's required natural gas leak abatement regulations in the fourth quarter of 2016. Additional rulemaking regarding ratemaking and performance-based financial incentives associated with the natural gas leak abatement program will follow in Phase II, although a specific timeline has not yet been established for that process. Given the potential for ARB's and the CPUC's requirements to overlap, however, SoCalGas suggests that ARB refrain from issuing a rule until the CPUC has completed at least the Phase I process.

Alternatively, ARB's proposed phase-in period could be extended to ensure that its regulations are implemented in way that does not duplicate efforts required by other agencies. For example, BLM/DOI has proposed for its regulations to be phased in over several years to allow operators to make the transition more cost-effectively.

If all of these proposed regulations are implemented at the same time or in rapid succession, it would create a logistical nightmare for affected entities. While the regulations may appear similar, it will take each agency and operator significant time and effort to figure out how each rule actually works in practice, and whether or not these perceived similarities are only superficial. For EPA's existing source rule, specific criteria that are not yet defined will need to be addressed. Even if the substantive regulations were to be exactly the same, it is extremely inefficient to require the same information to be reported to different agencies in different formats. Therefore, rather than adding another patch to the current and growing patchwork of regulations governing $CH_4$ emissions from oil and gas facilities, SoCalGas requests that ARB

[10] 80 FR 74068. EPA Request for Information, Oil and Natural Gas Sector: National Emission Standards for Hazardous Air Pollutants (November 27, 2015).

refrain from pursuing additional regulations at this time and allow the processes of other agencies to more fully run their course.

## Attachment F: GWP Reference Table by Governmental Program

### GWP Reference Table by Governmental Program

| Agency | Program/Policy/Regulation | IPCC Report Referenced | Methane GWP |
|---|---|---|---|
| **EPA** | Greenhouse Gas Reporting Program (Mandatory reporting) | AR4 except AR5 for those gases that did not have value in AR4 - both 100 yr. | 25 |
| **EPA** | Inventory of Greenhouse Gas Emissions and Sinks (Inventory) | AR4 - 100 yr. | 25 |
| **EPA** | Voluntary Methane Reduction Programs: | AR4 - 100 yr. | 25 |
| **EPA** | Natural Gas STAR Methane Challenge Program | AR4 - 100 yr. | 25 |
| **EPA** | AgSTAR | AR4 - 100 yr. | 25 |
| **EPA** | Global Methane Initiative | AR4 - 100 yr. | 25 |
| **EPA** | Coalbed Methane Outreach Program (CMOP) | AR4 - 100 yr. | 25 |
| **EPA** | Landfill Methane Outreach Program (LMOP) | AR4 - 100 yr. | 25 |
| **ARB** | Mandatory Reporting Regulation | SAR - 100 yr. | 21 |
| **ARB** | AB 32 Cap and Trade Regulation | SAR - 100 yr. | 21 |
| **ARB** | 2014 Statewide GHG Emission Inventory | AR4 - 100 yr. | 25 |
| **ARB** | Low Carbon Fuel Standard | AR4 - 100 yr. | 25 |