Tim Carmichael
Agency Relations Manager
State Government Affairs

925 L Street, Suite 650
Sacramento, CA 95814

Tel: 916-492-4248
TCarmichael@semprautilities.com

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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 the Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities Proposed 15-Day Modifications

Dear Mr. Fischer,

Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) appreciate the opportunity to review and submit comments on the California Air Resources Board's (ARB) Proposed 15-Day Modifications to the Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.

We would like to thank staff for working with stakeholders throughout the rulemaking process. This Proposed 15-Day version incorporates most of the feedback that SoCalGas and SDG&E have provided, and reflects the hard work that staff have put into the rule since 2014. In this letter we provide feedback on remaining rule items that have not yet been addressed in this version.

1. Enforcement Provisions Should Be Clarified to Achieve Regulatory Objectives and Incentivize GHG Reduction Efforts

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 95674(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 95674(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 95675(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:

> § 95675. Enforcement. … (c) Each metric ton of methane emitted in violation of this subarticle constitutes a single, separate, violation of this subarticle **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)**.

In addition, SoCalGas and SDG&E urge ARB to clarify that Section 95675(f) requires intentional conduct and does not impose strict liability for inadvertent errors. Section 95675(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. Indeed, emission reports are generally prepared and submitted using spreadsheet programs that sometimes round off entries by default. It is also possible inaccurate information inadvertently could be "submitted" in good faith to ARB or local air districts implementing the Proposed Regulation. Moreover, the first clause in Section 95675(g) covers falsification of information, so subsection (f) is unnecessary. Accordingly, SoCalGas and SDG&E recommend deletion of Section 95675(f).

As an alternative, if ARB declines to remove Section 95675(f) from the regulations, then SoCalGas and SDG&E recommend that ARB clarify that the regulation is directed at knowing or intentional conduct:

> § 95675. Enforcement. … (f) **Knowingly** submitting or producing inaccurate information required by this subarticle shall be a violation of this subarticle.

For both our primary recommendation (deleting Section 95675(f)) and alternative recommendation (inserting knowledge qualifier into Section 95675(f)), the second clause of subsection (g) ("or submitting or producing inaccurate information") should be deleted as it is duplicative.

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.

2. Compliance with Leak Detection and Repair Requirements Makes Unsubstantiated Quarterly Distinction

In general, the Proposed 15-Day version's edits to Section 95669(o) better incentivize operators to locate and repair leaks by providing a limited safe harbor from enforcement for self-discovered leaks. We appreciate ARB's willingness to work with stakeholders to address this important incentive structure. However, Section 95669(o)(5) would exclude from this safe harbor leaks discovered during the 4th Quarter of each calendar year. As such, leaks discovered during the last three months of a year would be treated in a radically different way than leaks discovered during the first nine months of a year, with leaks discovered in October – December constituting violations.

This temporal distinction is nonsensical, is inconsistent with the objective of LDAR programs, and there is no rational basis in the administrative record supporting it. LDAR requires periodic leak surveys because leaks in pressurized systems will occur *periodically* regardless of calendar quarter or operator diligence (e.g., due to thermal cycling, vibration, etc. associated with typical operations of the affected components). If finalized, the Proposed 15-Day version's edits to Section 95669(o)(5) would undercut ARB Staff's expressed intent for the Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities Oil: "This modification was necessary to provide operators with the ability to find and repair leaks throughout the calendar year without a penalty which is consistent with the intent of the proposed regulation."[1]

Further, we recommend clarifying that leaks discovered during an Air District inspection similarly enjoy the limited safe harbor. Accordingly, we recommend the revision of Section 95669(o)(5) as follows:

> (5) ~~Except for the fourth (4th) quarterly inspection of each calendar year, leaks~~Leaks discovered during an operator or Air District conducted inspection shall not constitute a violation if the leaking components are repaired within the timeframes specified in this subarticle.

3. Method 21 Concentration-Based Rule Provisions Are Not Supported

As discussed in our previously submitted comments, 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 assumptions used by ARB that are the basis for the proposed rule.

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

[1] ARB, Notice of Public Availability of Modified Text and Availability of Additional Documents and/or Information – Proposed Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, at 18 (February 3, 2017).

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 10,000 ppmv. ARB should 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)].

Further, the ARB report "Enhanced Inspection & Maintenance for GHG & VOCs at Upstream Facilities" posted to the rule docket provides additional documentation to support the above assertions[2]. The ARB study results are presented graphically in Figure 2-7 of the report, and correlation equations are provided that allow calculation of leak emission rate estimates for different component types based on the EPA Method 21 screening value (SV) measured. In §§95669(h) and (i), the ARB proposed rule includes LDAR criteria and repair actions based on Method 21 concentration screening values of 1,000 ppmv, 10,000 ppmv, or 50,000 ppmv. Summary observations regarding the estimated leak emissions rates from the ARB report follow. A more detailed analysis is provided in Attachment A.

- An average component leak with a SV of 1,000 ppmv leaks a negligible amount of gas, less than 1 (one) scf of natural gas per <u>year</u> with a value of less than one cent per year (assuming a gas price of $3.44 per MCF).
- An average component leak with a SV of 10,000 ppmv leaks less than 20 scf of per <u>year</u> with a value of less than 10 cents per year. The average mass emissions rate for 10,000 ppm leaks is less than 0.03 metric tons CO_2e per year[3]. ARB has not justified why leaks of this magnitude or smaller warrant regulatory control.
- An average component leak with a SV of 50,000 ppmv leaks about 200 scf of natural gas per <u>year</u> (or about 0.3 metric tons CO_2e per year) with a value of less than $1.00 per year. This relatively low emission rate is significant because the proposed rule requires aggressive action for leaks with a SV above 50,000 ppmv and requires such leaks to be eliminated after 2020. As discussed in previous SoCalGas comments, the Method 21 screening value is not indicative of a very large leak, and the proposed measures associated with 50,000 ppmv leaks are not warranted.
- These very small emission rates demonstrate that rule provisions that require leak repairs in a short prescribed time period [e.g., 2 or 5 calendar days in §95669(i)] cannot be cost-effective if the repair cannot be completed immediately (i.e., successful immediate repair is not possible). Daily leak emissions are negligible (e.g., about 1 gram per day for a 10,000 ppm leak) and do not justify the labor cost for an operator to repair such leaks outside their normal maintenance schedule. As discussed in Attachment A, if repairing the leak within the prescribed time includes actions such as additional vehicle trips (e.g., for parts or special services) or de-pressuring the system, the associated emissions will exceed the leak repair reduction in many cases.

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[2] "Enhanced Inspection & Maintenance for GHG and VOCs at Upstream Facilities," SAGE Environmental Consulting, December 2016

[3] CO_2e emissions based on global warming potential of 72.

This information supports previous SoCalGas comments recommending a leak concentration threshold of 10,000 ppm (rather than lower values), and identifying the inability to equate a leak that screens at 50,000 ppm as an especially large emitter.

4. 2020 LDAR Requirement Are Not Achievable

SoCalGas and SDG&E remain very concerned with the allowable leak thresholds set for 2020 and beyond and believe that it is not practical or meaningful to prescribe the proposed 2020 leak thresholds, nor achievable to reach such levels. As we explain above, a high concentration measurement does not always correlate to a high-emission leak and there is a strong likelihood that low-emission but high concentration leaks could trigger violations.

We recommend that ARB allow time to evaluate collected data from the LDAR program to assess program efficacy before committing to the limits set beginning January 2020 (Tables 3 and 4). Further, as explained in the Proposed Regulation Staff Report, the allowable number of leaks in Tables 1 and 2 were modeled after existing local air district regulations, which also allowed quarterly inspections to be reduced to annual inspections if a facility maintained compliance for five consecutive quarters[4]. As the revised rule no longer allows quarterly inspections to be reduced to annual, the allowable number of leaks are not appropriate and should be removed.

Accordingly, we recommend the removal of the 2020 allowable number of leaks and repair time periods, and the revision of section 95669(i) as follows:

(i) On or after January 1, 2020, **<u>ARB will evaluate the reported leak data to determine if the thresholds and associated repair time periods should be adjusted</u>**<u>.</u>

5. ARB Should Consider Safety Concerns with Vapor Collection

Section 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 from a safety standpoint, 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.

As previously discussed with staff, a delay of repair provision should be added to §95671(f)(1)(b) to allow time to address technical and safety issues or to obtain permits. We recommend the addition as follows:

[4] ARB Staff Report: Initial Statement of Reasons. May 31, 2016.

§95671(f)(1)(b) A delay of repair shall be granted by the ARB Executive Officer if the owner or operator can provide proof that the parts or equipment required to make necessary repairs have been ordered.

***i.* A delay of repair to obtain parts or equipment shall not exceed 30 calendar days, or 60 days from the date from of the initial measurement, unless the owner or operator notifies the ARB Executive Officer to report the delay and provides an estimated time by which the repairs will be completed.**

6. Rule Should Provide Flexibility for Storage Monitoring Plans

The natural gas underground storage facility monitoring requirements entail multiple layers of redundancy: 1) continuous ambient monitoring; 2) daily or continuous wellhead monitoring; 3) quarterly LDAR; and 4) daily audio-visual inspection under LDAR. As explained in our previous comment letter, ARB must consider how the high costs of implementing these redundant measures would not provide any meaningful emissions reduction benefits, nor even prevent a large leak[5]. In addition, the Division of Oil, Gas, & Geothermal Resources (DOGGR) has proposed regulations that already require real-time well pressure monitoring for each wellhead[6], which would detect operating anomalies that trigger investigation before a major leak occurs.

SoCalGas and SDG&E also recommend that the plan allow for more flexibility to allow operators to use technology and processes best suited to the unique characteristics of a storage field location, such as size, terrain, etc. This is consistent with previous staff comments on avoiding an overly prescriptive regulation, and allowing operators to design a plan that meets regulatory objectives.

We provide the following specific comments on the revised monitoring requirements:

A. Monitor specifications should be flexible. ARB has added specific requirements for upwind and downwind sensors at storage facilities. While SB 887 language requires monitoring “at sufficient locations” throughout the facility, it does not specify anything further. We, therefore, recommend that the rule allow flexibility for the operator to determine the configuration of the monitoring system, as part of the plan submittal.

- §95668(h)(5)(A): Measurements by the upwind monitor are not considered for the alarm system referenced in §95668(h)(5)(A)7 and the measurements have no utility. ARB does not justify the need for the upwind monitors, and they are an unsupported and unwarranted expense and should be removed from the rule.

[5] SoCalGas and SDG&E Comments on Proposed Regulation, filed July 18, 2016.
[6] DOGGR Draft Regulations section 1726.7 (a)

- If the requirement is retained, monitoring should be limited to one upwind and one downwind monitor, as reflected in ARB's cost estimates. ARB Attachment 2 analysis assumes two ambient monitoring stations for each facility. The continuous air monitoring requirements in the proposed rule are ambiguous. The rule text should reflect ARB's associated support analysis, and codify this monitoring approach:

  "Continuous air monitoring to measure upwind and downwind ambient concentrations of methane ~~at sufficient locations throughout the facility to identify methane emissions in the atmosphere~~."

  1. The monitoring system must have ~~at least~~ one sensor located in a predominant upwind location and ~~at least~~ one sensor located in a predominant downwind location with the ability to continuously record measurements."

- The 250 ppb accuracy requirement for ambient monitors is ambiguous and requires a measurement concentration or range to provide context. In addition, since methane monitoring technology continues to be developed, the proposed requirement could exclude viable technologies. Additional flexibility is warranted, and the accuracy requirement should be reflected as a relative accuracy rather than absolute accuracy. The following context is based on the average ambient methane concentration in California, which is about 2 ppmv, and includes flexibility for new technologies that may become available. We propose the following changes:

§95668(h)(5)(A)1.a: "The upwind and downwind instruments shall have the capability to measure ambient concentrations of <u>**2 ppmv**</u> methane within minimum 250 ppb accuracy to determine upwind and downwind emissions baselines<u>**, or other performance criteria approved by the ARB Executive Officer**</u>."

B. Alarm system requirements should be revised. Section 95668(h)(5)(B) requires notification to regulatory agencies any time a leak above 50,000 ppmv is identified or above 10,000 ppmv is identified for more than five continuous days. Leak rate / Method 21 concentration correlations from ARB's recently released Enhanced I&M Report (discussed above and in Attachment A) indicate that:

- Average 10,000 ppmv leaks from connectors, flanges, and valves in natural gas service emit less than 0.2 pound of methane per year (or less than 0.25 gram per day), and
- Average 50,000 ppmv leaks from connectors, flanges, and valves in natural gas service emit about 1 to 2 pounds of methane per year (or about 1 to 2 grams per day).

ARB has not justified why such small leaks warrant regulatory notification. Further, as noted above, an alarm is required if instrumentation detects "a leak" above 10,000 ppmv for more than 5 continuous days. Then, §95668(h)(5)(B)(6) requires notification to state and local agencies if a leak is identified based on a subsequent Method 21 survey. As discussed in the previous item, and discussed further below and presented in Attachment A, Table 2, leaks can be very small at this concentration level and notifications may not be warranted.

Implementation is also not clear – e.g., it is not clear if a single instantaneous measurement above 10,000 ppmv once per day for 6 days would result in the conclusion that the, "10,000 ppmv leak persists for more than 5 continuous calendar days." SoCalGas recommends a revision to the response required if continuous instrumentation persistently detects a leak larger than 10,000 ppmv. If the leak is investigated and repaired per §95668(h)(5)(B)(3) and (4), and recorded and reported per §95668(h)(5)(B)(7) and (8), notifications should not be required. Based on the leak rates noted in Attachment A, Table 2 (e.g., ARB report correlation equations show average emission rates of 0.2 to 2 grams per day), notifications to several state and local agencies are not warranted.

C. **More time is needed for revisions of monitoring plan.** We appreciate that ARB allows 180 days for operators to implement monitoring plans after approval, as we had requested. However, the rule still only provides 14 days for revisions if ARB disapproves the operator plan. 14 days is not sufficient time to revise a storage facility monitoring plan, particularly when it is considered these will be the initial plans and that ARB will be approving or disproving the plans just prior to the July 4th holiday. A minimum 60-day time period is needed. We provide the following edits:

   §95668(h)(3)(A): "Revisions to monitoring plans must be submitted to ARB within ~~14~~ **60** calendar days of ARB notification"

   §95668(h)(3)(B) "ARB will approve in full or in part, or disapprove in full or in part, the revisions to the monitoring plan within 14 calendar days of submittal to ARB. **If ARB does not respond with the 14 calendar days the monitoring plan is approved in full.**"

D. **Well blowout -** Assuming ARB retains Section 95675(c), we recommend that a well blowout not be considered a violation and that new Section 95668 (i)(5)(B)(5) be deleted in its entirety. In that scenario, the rule would fully cover the climate impact of a well blowout and operators would be fully incentivized to avoid well blowouts.

SoCalGas and SDG&E would like to thank ARB staff for considering our feedback. Please contact me if you have any questions or concerns about these comments.

Sincerely,

/s/ Tim Carmichael

Tim Carmichael
Agency Relations Manager
SoCalGas and SDG&E

Attachment A: ARB's Enhanced I&M Report data supporting SoCalGas comments, including additional examples and analysis

On February 3, 2017, ARB released a report prepared by Sage Environmental, "Enhanced Inspection & Maintenance for GHG & VOCs at Upstream Facilities – Final (Revised)." As discussed in the comments and further explained below, the ARB report supports previous SoCalGas comments questioning the leak definition (i.e., based on an EPA Method 21 screening value (SV) of 1,000 ppmv versus 10,000 ppmv) and related requirements for repair schedules and other criteria associated with those two screening values and a SV of 50,000 ppmv.

The report presents results from an ARB field study that measured mass emissions from leaking components in natural gas service, and correlated emission rates with EPA Method 21 screening values (SVs). This is consistent with historical studies that have developed "correlation equations" for leaks where the estimated leak rate is a function of the Method 21 screening value.

In previous comments, SoCalGas has provided examples of very low mass emissions associated with some leaks, and the ARB Enhanced I&M Report provides additional documentation to support those assertions. The ARB study results are presented graphically in Figure 2-7 of the report, and correlation equations are provided that allow emission rate calculations for different component types.

Emission rates can be calculated using the correlation equations and analysis can consider associated proposed rule benefits based on those results. For example, in §§95669(h) and (i), the ARB proposed rule includes LDAR criteria and repair actions based on SVs of 1,000 ppmv, 10,000 ppmv, or 50,000 ppmv. The associated emission rates can be calculated and implications assessed.

<u>Overview of Emission Levels based on ARB Enhanced I&M Report Screening Value Correlations</u>

Tables 1 through 3 present calculated hourly or annual emission rates for key proposed rule SV thresholds. The value of the gas saved presented in the tables is based on a natural gas price of $3.44 per MCF[1].

- An average component leak with a SV of 1,000 ppmv leaks a negligible amount of gas, less than 1 (one) scf of natural gas per <u>year</u> with a value of less than one cent per year.
- An average component leak with a SV of 10,000 ppmv leaks less than 20 scf of natural gas per <u>year</u> with a value of less than 10 cents per year. The average mass emissions rate for 10,000 ppm leaks is less than 0.03 metric tons CO_2e per year. ARB has not justified why leaks of this magnitude or smaller warrant regulatory control.
- An average component leak with a SV of 50,000 ppmv leaks about 200 scf natural gas of per <u>year</u> with a value from saved gas of less than $1.00 per year. This relatively low emission rate is significant because the proposed rule requires aggressive action for leaks with an SV above 50,000 ppmv and requires such leaks to be eliminated after 2020. As discussed in previous SoCalGas comments and demonstrated in Table 3, the Method 21 screening value is not necessarily indicative of a very large leak, and the measures associated with 50,000 ppmv leaks are not warranted.
- These very small emission rates demonstrate that rule provisions that require leak repairs in a short prescribed time period [e.g., 2 or 5 calendar days in §95669(i)] cannot be cost-effective if the repair cannot be completed immediately (i.e., successful immediate repair is not possible). Daily leak emissions are negligible (e.g., about 1 gram per day for a 10,000 ppm leak) and do not justify the labor cost for an operator to repair such leaks outside their normal maintenance schedule.

  For example, the incremental emissions associated with repairing a 10,000 ppmv leak after 30 days rather than 5 days is about 4 lbs (or 0.002 metric tons) of CO_2e (based on a GWP of 72). If an operator was required to make a designated trip to repair the leak to meet a 5 day repair time period,

[1] $3.44 per MCF is the natural gas value used by ARB in its economic analysis.

and the repair required one hour at $60/hr, the cost-effectiveness associated with the incremental leak reduction would be about $30,000 per metric ton. Further, and as discussed below and shown in Figure 1, a light duty truck emits about one pound of CO_2 per mile. Thus, if the designated trip to repair the leak to meet the 5 day repair time period required more than 4 miles of driving, rule compliance would cause a net increase in GHG emissions.

Tables 1 – 3 present average leak emission rates based on correlation equations from the ARB study. Averages are based on the emission rates for the four component types. Weighted averages presented in the tables consider the number of each type of component included in the study. That last column in each tables presents the value of gas saved based on a natural gas price of $3.44 per MCF.

Table 1. Average Leak Rate Emissions, Method 21 Screening Value = 1,000.

Component	TOC (as CH4) Leak Rate for M21 Screening Value of 1,000 ppmv							
	kg/hr	gram/ day	lb CO2e/ day	lb/yr	mt CO2e/ yr	scf/hr	scf/yr	$/yr
Valves	4.6E-7	1.1E-2	1.7E-3	8.9E-3	2.9E-4	2.4E-5	0.21	$0.001
Connectors & Flanges	9.7E-7	2.3E-2	3.7E-3	1.9E-2	6.1E-4	5.0E-5	0.44	$0.002
OELs	3.0E-6	7.1E-2	1.1E-2	5.7E-2	1.9E-3	1.5E-4	1.35	$0.005
Other components	1.2E-6	2.8E-2	4.4E-3	2.3E-2	7.4E-4	6.1E-5	0.53	$0.002
Average	**1.4E-6**	**3.3E-2**	**5.3E-3**	**2.7E-2**	**8.8E-4**	**7.2E-5**	**0.63**	**$0.00**
Weighted Average	**1.3E-6**	**3.2E-2**	**5.1E-3**	**2.6E-2**	**8.4E-4**	**6.9E-5**	**0.61**	**$0.00**

Table 2. Average Leak Rate Emissions, Method 21 Screening Value = 10,000.

Component	TOC (as CH4) Leak Rate for M21 Screening Value of 10,000 ppmv							
	kg/hr	gram/ day	lb CO2e/ day	lb/yr	mt CO2e/ yr	scf/hr	scf/yr	$/yr
Valves	9.9E-6	0.24	0.04	0.19	0.006	5.1E-4	4.50	$0.02
Connectors & Flanges	7.7E-6	0.18	0.03	0.15	0.005	4.0E-4	3.50	$0.01
OELs	8.0E-5	1.93	0.31	1.55	0.051	4.2E-3	36.70	$0.13
Other components	6.6E-5	1.59	0.25	1.28	0.042	3.5E-3	30.30	$0.10
Average	**4.1E-5**	**0.99**	**0.16**	**0.79**	**0.026**	**2.1E-3**	**18.75**	**$0.06**
Weighted Average	**3.6E-5**	**0.86**	**0.14**	**0.70**	**0.023**	**1.9E-3**	**16.46**	**$0.06**

Table 3. Average Leak Rate Emissions, Method 21 Screening Value = 50,000.

Component	TOC (as CH4) Leak Rate for M21 Screening Value of 50,000 ppmv							
	kg/hr	gram/ day	lb CO2e/ day	lb/yr	mt CO2e/ yr	scf/hr	scf/yr	$/yr
Valves	8.4E-5	2.02	0.32	1.62	0.05	4.4E-3	38	$0.13
Connectors & Flanges	3.3E-5	0.78	0.12	0.63	0.02	1.7E-3	15	$0.05
OELs	8.1E-4	19.35	3.07	15.57	0.51	4.2E-2	368	$1.27
Other components	1.1E-3	26.81	4.26	21.58	0.70	5.8E-2	510	$1.76
Average	**5.1E-4**	**12.24**	**1.94**	**9.85**	**0.32**	**2.7E-2**	**233**	**$0.80**
Weighted Average	**4.4E-4**	**10.51**	**1.67**	**8.46**	**0.28**	**2.3E-2**	**200**	**$0.69**

Related Analysis and Comments: Emission rates and proposed storage monitoring and LDAR criteria

- Screening Value-based Notification Criteria in §95668(h)(5)(B): This section requires notification to regulatory agencies any time a leak above 50,000 ppmv is identified or above 10,000 ppmv is identified for more than five continuous days. Leak rate / Method 21 concentration correlations from ARB's recently released Enhanced I&M Report (discussed further below) indicate that:

  - Average 10,000 ppmv leaks from connectors, flanges, and valves in natural gas service emit less than 0.2 pound of methane per year (or less than 0.25 gram per day), and

  - Average 50,000 ppmv leaks from connectors, flanges, and valves in natural gas service emit about 1 to 2 pounds of methane per year (or about 1 to 2 grams per day).

  ARB has not justified why such small leaks warrant regulatory notification.

- Emissions Implications from Repair Schedules in §§95669(h) and (i): These two sections define repair schedules based on SVs. SoCalGas recommends revisions to allow more appropriate repair schedules. For example, GHG emissions from driving to repair leaks may be *higher* than the emissions that are reduced if unscheduled trips are required.

  Example scenarios are provided to compare and contrast emissions from actions that would result from proposed rule requirements. For example, the cited rule sections list schedules for repairing leaks based on the SV, and leaks must be successfully repaired or removed from service within as little as 2 calendar days of initial leak detection. In some cases (e.g., when a first attempt at repair is not possible or not successful), this may require an expedited response including personnel working weekends and holidays. It does not appear that ARB has considered the GHG emissions caused by such an expedited response, the associated environmental benefit (or dis-benefit), or the cost-effectiveness of such an expedited response.

  The following examples illustrate potential emissions reductions from leak repair and related emission increases from vehicle travel if unplanned trips are required. The emissions dis-benefit discussed below can be further compounded if equipment de-pressurization is required to safely perform the repair. That analysis is not presented here, but could be completed to demonstrate additional emission dis-benefits from prescribed repair schedules that do not consider operational and logistical factors. Emission rates from correlation equations in ARB's Enhanced I&M Report can be used to assess and compare emission levels from the leak and from vehicle travel:

  - GHG emissions from additional driving caused by an expedited response can exceed incremental GHG emission reductions. Figure 1 shows cumulative GHG emissions (as CO_2e, GWP = 72 for methane) for two average leak rates for **50,000** ppm leaks (leak concentration as methane measured by EPA Method 21). Such leaks will be rare, and leak rates (and emissions reductions) will typically be *much lower* than presented in Figure 1. The 2 grams methane per day leak rate applies to connectors, flanges, and valves, and the 25 grams methane per day leak rate applies to OELs and other components (refer to ARB's Enhanced DI&M Report and Table 3 above). Light duty trucks emit about 1 pound of CO_2 per mile[2].

    - In Figure 1, the red line estimates the CO_2 emissions if an employee drove 40 miles (roundtrip) to repair a leak. For example if they had to work on a weekend and make a special trip to repair the component, or if an unplanned trip was required to meet the repair schedule. The vehicle emissions would exceed the GHG emissions for 10 days of gas leakage at 25 grams of methane per day and *months* of GHG emissions for gas leakage at 2 grams of methane per day. The employees may drive further than 20 miles (one way) to address the required leak repair schedule.

[2] Based on CO_2 emissions from motor gasoline combustion of 20 pounds per gallon, with the truck averaging about 20 mpg.

- In Figure 1, the blue line estimates the CO_2 emissions if an employee drove 10 miles (roundtrip) to repair a leak, for example if they had to make a special trip within a large gas storage facility to repair the component. This would equal the GHG emissions for about 3 days of gas leakage at 25 grams of methane per day and about 25 days of GHG emissions for gas leakage at 2 grams of methane per day.

The leak repair reductions are further offset by vehicle methane emissions, which are not presented in Figure 1. For example, based on an EPA report,[3] gasoline fueled trucks emit 0.02 to 0.05 grams of methane per mile. For a 10 miles trip, this is 0.2 to 0.5 grams of methane emissions (versus a very conservatively high leak rate of 2 or 25 grams per day shown in Figure 1). For a 40 mile trip, this equates to 0.8 to 2.0 grams of methane emissions – or a similar magnitude as the daily leak rate.

The approximate cost-effectiveness (i.e., \$ / metric ton of incremental CO_2e emission reductions) can also be considered, independent of the emissions dis-benefit discussed above. The cost for an expedited leak repair is well above \$10,000/metric ton, which is a very high value for GHGs. For example, personnel working two hours on a weekend or over-time at a fully burdened cost of \$60/hr to specifically repair a 2 gram methane per day leak (e.g., to meet a 2 calendar repair time schedule), that could have been repaired during a normal rounds ten days later, would cost about \$100,000 per incremental metric ton CO_2e emission reductions.

In sum, repair time periods should be of sufficient duration that repairs can be conducted during a normal and organized repair schedule that would not require unnecessary site visits (i.e., driving) that will result in excess GHG emissions, as well as to avoid extremely disproportionate costs relative to the incremental emission reductions. The rule should allow a minimum of 10 business days. If equipment venting is required to complete the repair, then the repair schedule should allow additional time, as warranted. Repair at the next scheduled process shutdown may be appropriate.

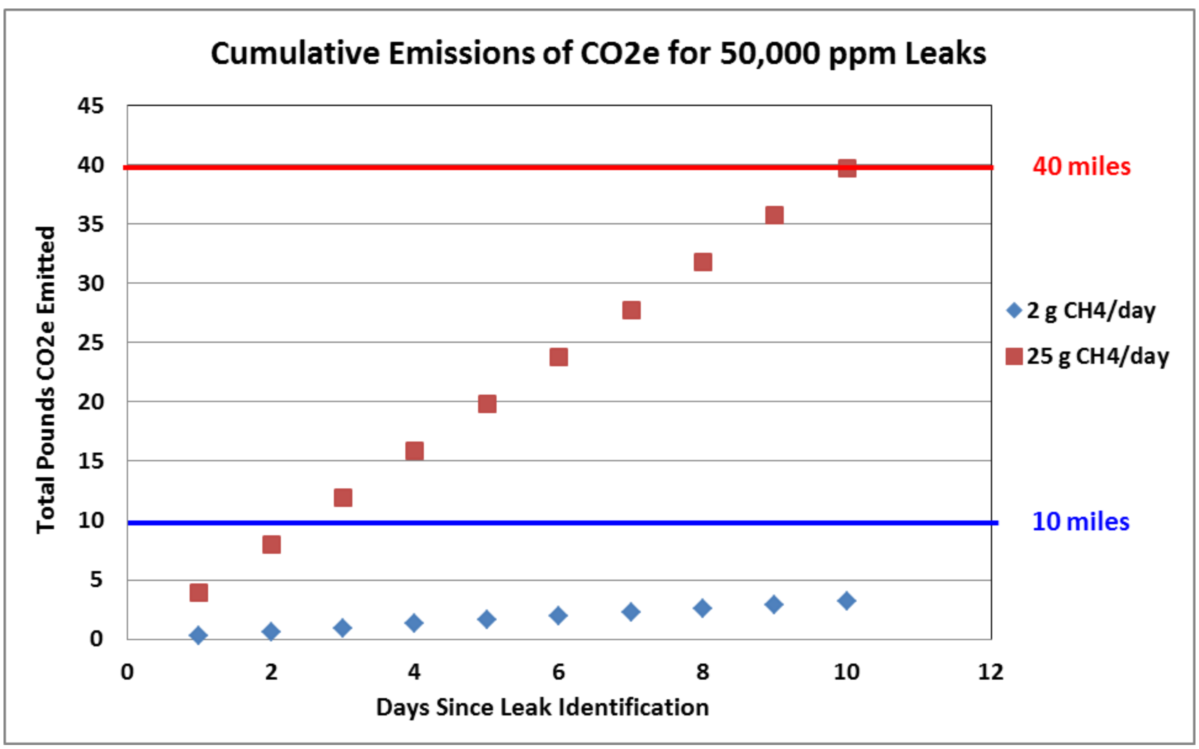

Figure 1. Compare cumulative CO_2e emissions by day (for average 50,000 ppm leaks) to emissions from vehicles mileage to address leak repair. Methane GWP = 72.

[3] EPA420-P-04-016, "Update of Methane and Nitrous Oxide Emission Factors for On-Highway Vehicles," Table 10, (November 2004).

- Screening value for leak definition: §95669(h) – (i) include leak definitions for 2018 through 2019, and starting January 1, 2020. The emission rates presented above indicate very low average emissions from leaks at 10,000 ppmv or 1,000 ppmv, and the emissions information supports previous SoCalGas comments recommending a leak concentration threshold of 10,000 ppm (rather than lower values). Or, at a minimum, SoCalGas has recommended that ARB evaluate the program after two years rather than presuming more stringent criteria are warranted in 2020.
- Repair schedules and maximum allowed screening value: The same two sections of the proposed rule define repair schedules based on the SV as well as the number of leaks allowed. In addition to very low emission rates at SVs of 1,000 or 10,000 ppmv presented in Tables 1 and 2, Table 3 also demonstrates the inability to equate a leak with an SV of 50,000 ppm as an especially large emitter. For currently proposed criteria based on SV tiers, analysis of the emissions benefit and costs of required actions do not withstand scrutiny when considering emission rates based on ARB study results.

Uncertainty from EPA Method 21 Instrumentation

The ARB report also demonstrates the arbitrary nature of leak concentration thresholds by comparing the response of Method 21 instruments. The study evaluated three different leak detection instruments that meet EPA Method 21 Performance criteria. Leaking components were monitored by each instrument in close succession. Table 4 compares measured concentrations for three instruments for leaks in the 1,000 to 10,000 ppmv range.

Table 4. Data from Table 3-9 of the Sage Study Report "Comparative Monitoring Results for Method 21 Compatible Instruments"

Item #	Component Description	Leak Concentration			Max / Min
		TVA (ppm)	RKI Eagle (ppm)	COSMOS (ppm)	
39	Level Controller	1,200	1,200	1,400	117%
40	Connector	3,100	2,390	3,400	142%
41	OEL	3,200	3,450	8,900	278%
42	Controller	5,000	5,400	5,800	116%
43	Pressure regulator	6,100	4,900	7,300	149%
44	Connector	6,900	3,400	10,100	297%

Measured hydrocarbon concentrations differed for every leak, with differences as large as a factor of 3. Comment 15 in the SoCalGas/SDG&E comments dated July 18, 2016 regarding the proposed ARB methane rule discusses why EPA Method 21 gas leak concentration measurements (i.e., screening values) have a very large uncertainty, and should not be the sole basis for leak repair thresholds, schedules, and rule compliance determinations. Separate from the discussion above regarding the emission rates in Tables 1 through 3, the data in Table 4 demonstrate additional ambiguity and uncertainty that can occur from instrumentation-based differences in defining and assessing the significance of a leak. Collectively, this information supports SoCalGas comments that a leak definition of 10,000 ppmv is more appropriate than 1,000 ppmv.

Attachment B: Costs Estimates for LDAR and Storage Monitoring

ARB documents released on February 3, 2017 include updates to cost and emission estimates, posted on the ARB website as “Attachment 2.” Tables below summarize ARB cost estimates for LDAR and storage monitoring, and present cost estimates from SoCalGas for comparison. A summary of key points follow.

LDAR Economic Analysis

Table 1 compares the ARB analysis to SoCalGas cost estimates for LDAR programs. As discussed in previous SoCalGas comments, available documentation indicates that ARB’s targeted emission reduction can be achieved with annual rather than quarterly survey frequency. Thus, the SoCalGas analysis includes costs for quarterly or annual surveys, and considers two values for methane global warming potential (GWP). The gray rows highlight *parameter assumptions* that differ significantly for ARB and SoCalGas. The yellow rows highlight the two primary results: total annual LDAR cost and LDAR cost effectiveness. The comparisons indicate:

- ARB’s LDAR cost estimate for quarterly surveys is similar to SoCalGas costs for *annual* surveys. The SoCalGas costs indicate quarterly surveys are about 4 times more costly than ARB’s estimate.
- The SoCalGas estimate assuming quarterly surveys and the commonly used GWP based on a 100-year time horizon (GWP = 21) shows a cost effectiveness value over 8 times higher than ARB’s estimate (i.e., \$193.78 per metric ton CO_2e reduced versus \$23.48 per metric ton).

Storage Monitoring Economic Analysis

Table 2 compares several storage monitoring scenarios from the ARB analysis to the SoCalGas cost estimate for continuous monitoring. This includes ambient monitoring requirements and well-related monitoring requirements in §98668(h) of the proposed rule. The yellow rows highlight total costs for different components of the storage monitoring program.

For ambient monitoring, the costs for ARB and SoCalGas are similar. However, as discussed in SoCalGas comments, the cost estimate is based on two total monitors, which is not clearly indicated in the proposed rule. If additional ambient monitors are required, costs (relative to Table 2 estimates) would increase approximately 50% for each additional monitoring location.

Similar to the comment below for wellhead monitoring, these costs do not include costs for infrastructure. It is unlikely that relatively remote ambient monitor sites will have power access, and significant costs could be incurred to provide power, and develop access roads, instrumentation pads, etc.

For wellhead monitoring, ARB assumes that continuous monitoring instruments will be employed with 10% or less of the wells monitored manually. Table 2 presents comparisons assuming continuous wellhead monitoring. ARB has not adequately considered costs for *manual* wellhead monitoring:

- SoCalGas anticipates that manual monitoring will be employed at some or all sites, at least in initial years of the program. As discussed in previous SoCalGas comments, additional evaluation is needed to assess the viability of continuous monitoring systems to meet proposed requirements. Many methane monitoring technologies are still experimental or developmental, such as those being developed under the DOE ARPA-E research program.
- For daily manual monitoring, SoCalGas experience is that costs are approximately \$20,000 per well per year. For example, approximately \$2.4 million per year at one facility. This is an *ongoing annual cost*.

- The Table 2 costs are total statewide estimates for 14 storage facilities. The total continuous wellhead monitoring costs for the 14 facilities are $3.5 to $7.8 million, so the average annual costs are $250,000 to $560,000 per facility. This estimate is significantly lower than the annual $2.4 million cost for manual monitoring based on SoCalGas experience.
- Since manual monitoring is likely to be much more prevalent than forecast by ARB, the wellhead monitoring costs are significantly underestimated.

In addition, for *continuous* wellhead monitoring, cost estimates do not include infrastructure needed to implement the program. For example, power (electricity) will not be readily available at all locations, and costs to provide power and develop pads and access roads could be significant, depending upon the location.

Table 1. Comparison of ARB and SoCalGas Economic Analysis for Proposed LDAR.

		ARB 2017	SCGas Quarterly (GWP = 72)	SCGas Annual (GWP = 72)	SCGas Quarterly (GWP = 21)	SCGas Annual (GWP = 21)	Notes
LDAR Inspections Costs							
Number of Components	A	1,585,653	1,565,168	1,565,168	1,565,168	1,565,168	ARB component count includes 20,485 well casings (excluded from SCGas analyses). Well casings require gas emission rate measurements, not Method 21 leak concentration measurements, and should not be included in this total. These costs should be determined separately.
LDAR survey team labor Rate ($/hr)	B	$60	$142.06	$142.06	$142.06	$142.06	ARB Labor rate based discussions with contractors. SCGas Labor rate from ICF 2016 (2-person team with travel and other ODC). A 2-person team is needed for this rule because survey requirements include carry OGI camera, recordkeeping, component counts (§95669(n)), and initial attempt at leak repair. In addition, 2-person teams is standard procedure due to safety considerations when working at remote locations (e.g., O&G production, storage fields)
Labor hours per survey team year	C	2,080	2,080	2,080	2,080	2,080	
Inspections per year	D	4	4	1	4	1	
Components per survey team year	E	70,720	70,720	70,720	70,720	70,720	Based on inspection rate of 34 components per hour (includes preparation and travel)
Annual LDAR Inspection Cost ($/yr)	F=A*B*C*D/E	$11,192,845	$26,158,561	$6,539,640	$26,158,561	$6,539,640	
		$11,192,845	*$26,158,561*	*$6,539,640*	*$26,158,561*	*$6,539,640*	*Calculation check*
Set up Cost							
Cost per Facility ($/Facility)	G	$1,500	$1,500	$1,500	$1,500	$1,500	
Number of Facilities	H	799	799	799	799	799	Number of Facilities at the time when the survey was conducted.
Number of Components from Survey	I	1,339,185	1,339,185	1,339,185	1,339,185	1,339,185	
Total One-time Set up Cost ($)	J=G*H*A/I	$1,419,076	$1,400,743	$1,400,743	$1,400,743	$1,400,743	
Capital Recovery Factor (CRF)	K	0.23	0.244	0.244	0.244	0.244	Based on experience, SCGas assumes LDAR vendors are periodically changed, assume after 5 years on average for all facilities and discount rate of 7%
Annualized Set-up Cost ($/year)	L=J*K	$326,387	$341,781	$341,781	$341,781	$341,781	
Recordkeeping & Reporting Cost							
R&R Cost per Person (Survey Team)Year	M	$15,000					
Total R&R Costs ($)	N=M*D*A/E	$1,345,294					Revised ARB Costs based on ICF document estimates.
Total R&R Costs ($)	N1=P*A/I		$2,486,032	$677,888	$2,486,032	$677,888	"P" from SCGas comments dated 7/18/16 (see Attachment A, row T). Number of facilities and businesses increased by ratio of "Number of Components" and "Number of Components from Survey," which is assumed to account for new facilities added since the survey was conducted.
Facility Support Cost							
Facility personnel support ($/Facility-yr)	Q=A*80*C*D/E	$0	14,730,993	3,682,748	14,730,993	3,682,748	SCGas estimates one hour of storage facility rep time (at $80/hr) required 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, M21 measurement of detected and repaired leaks, leak repair, etc.) - ARB assumes no facility support costs. ""Following the methodology from the ICF report, 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, the program serves to identify equipment failures sooner, benefiting the operator above and beyond business as usual. Thus only those repairs that are made on a first attempt are accounted for in this estimate, and are reflected in the 34 components per hour value."
Total Annual LDAR Inspection Cost	R=F+L+N+N1+Q	$12,864,526	$43,717,367	$11,242,058	$43,717,367	$11,242,058	
Annual Leak Emissions (mt CH4/yr)	S	11,407	11,407	11,407	11,407	11,407	From Tables A-1, A-2, and A-3 of Attachment 2.
LDAR Control Efficiency	T	60%	90%	80%	90%	80%	
Emission reductions by LDAR (mt CH4/yr)	U=S*T	6,844.28	10,266	9,126	10,266	9,126	
Global Warming Potential	V	72	72	72	21	21	GWP of 21 based on 100 year horizon and GWP of 72 based on 20 year horizon.
Annual Leak Emissions (mt CO2e/yr)	W=S*V	821,314	821,314	821,314	239,550	239,550	
Emission reductions by LDAR (mt CO2e/yr)	X=W*T	492,788.45	739,182.67	657,051.26	215,594.95	191,639.95	
LDAR Cost Effectiveness							
LDAR Cost Effectiveness ($/mt CO2e)	Y=R/X	$26.11	$59.14	$17.11	$202.78	$58.66	
Value of Recovered Gas	Z	$1,293,380					
	Z1=Z*T/60%		$1,940,070	$1,724,507	$1,940,070	$1,724,507	
LDAR Cost Effectiveness with Recovered Gas Savings ($/mt CO2e)	AA=(R-Z)/X	$23.48	$56.52	$14.49	$193.78	$49.66	

Table 2. Comparison of ARB and SoCalGas Economic Analysis for Proposed Storage Monitoring – Ambient and Wellhead Monitoring.

Parameter	Parameter ID	ARB Scenario 1 (SCGas, IR 5500 at each well)	ARB Scenario 2 (ultrasonic and IR at each well)	ARB Scenario 3 (Fixed OGI at Wells)	SCGas	
Continuous Ambient Air Monitoring Costs						
Capital Cost per Facility ($/Facility)	A	$400,000	$350,000	$350,000	$400,000	Costs based on ARB assumption of 2 monitors per facility. - SCGas EA: Estimated facility capital cost for multiple units (Boreal TDL based-technology) for 360 degree coverage. Actual capital costs will depend on requirements for "ambient" and "facility" monitoring, and instrument sensitivity requirements.
Capital Recovery Factor	B	0.13	0.13	0.13	0.142	10 year amortization, ARB at 5% discount rate, SCGas at 7% discount rate.
Capital Costs for Meteorological Station required by §95668(h)(5)(A)2. ($/Facility)	C	$0	$0	$0	$20,000	Assume 2 met stations, $10,000 each.
Annualized Capital Costs ($/Facility-yr)	D=B*(A+C)	$52,000	$45,500	$45,500	$59,640	
Annual O&M costs ($/Facility-yr)	E	$52,000	$179,000	$179,000	$52,000	SCGas EA: estimated costs for maintenance, calibration, spare parts, etc. Estimate 5% of monitors is replaced each year + $10,000 annual O&M per monitor
Annual O&M costs for Meteorological Station ($/	F	$0	$0	$0	$7,680	Assume 2 met stations, 4 hours maintenance and calibrations a month per station.
Number of Facilities	G	14	14	14	14	
Total Annual Cost	H=G*(D+E+F)	$1,456,000	$3,143,000	$3,143,000	$1,670,480	
Daily or Continuous Wellhead Monitoring Costs						
Capital Cost per Well ($/Well)	I	$77,000	$94,500	$30,000	$77,000	ARB Scenario 3, $90,000 to cover three wells. Assumption not supported. SC Gas EA: 2 pair IR 5500 at each well + 10% contingency.
Annualized Capital Costs ($/Well-yr)	J=I*B	$10,010	$12,285	$3,900	$10,934	
Annual O&M Costs ($/Well-yr)	K	$5,000	$5,000	$0	$5,000	ARB Scenario 3, no O&M costs. Assumption not supported. SCGas EA: estimates costs for maintenance, calibration, reporting, data review, and data compilation for external audiences. Estimate 5% of equipment is replaced each year + $3,500 annual O&M per well.
Number of Wells	L	452	452	452	452	
Annual OGI camera inspections ($ / Facility)	M	$0	$0	$123,839	$0	ARB Scenario 3, 10% of wells require OGI. This cost is about $38,500 per well per year. Would be less expensive to install the Fixed OGI at each well.
Total Annual Cost ($/yr)	N=L*(J+K)+M*G	$6,784,520	$7,812,820	$3,496,546	$7,202,168	ARB Scenario 3 has a calculation error, the Fixed OGI costs should only apply to 90% of the wells.
Recordkeeping & Reporting						
Monitoring Plan (MP) Development ($/Facility)	O	$20,000	$20,000	$20,000	$20,000	
Capital Recovery Factor	P	0.142	0.142	0.142	0.142	Adjusted ARB CRF to match ARB total cost. ARB used SCGas CRF.
Annualized MP Development Costs ($/Facility-yr	Q=O*P	$2,840	$2,840	$2,840	$2,840	
Annual MP Updates ($/Facility-yr)	R	$4,000	$4,000	$4,000	$4,000	
Annual Reporting Cost ($/Business-yr)	S	$20,800	$20,800	$20,800	$20,800	
Number of Businesses	T	6	6	6	6	
Annual Recordkeeping Cost ($/Facility-yr)	U	$83,200	$83,200	$83,200	$83,200	
Total Annual Cost ($/yr)	V=S*T+G*(Q+R+U)	$1,385,360	$1,385,360	$1,385,360	$1,385,360	
Screen and Repair Detected Leaks						
Annual repairs ($/Facility)	W	$134,682			$134,682	Annual cost to screen and repair Method 21 detected leaks in accordance with §95668(h)(5)(B)3. & 4. SCGas cost estimate from SCGas comments dated 7/18/16 (see Attachment A1, row G6).
Total Annual Cost	X=G*W	$1,885,548			$1,885,548	
Total Annual Monitoring Cost	Y=H+N+V+X	$11,511,428	$12,341,180	$8,024,906	$12,143,556	

Attachment C: Additional Comments and Rule Language Modifications

Suggested Language modifications: **<u>additions</u>** and ~~deletions~~

1. **§95667(a) Definitions**
   The thresholds specified in this article are associated with a concentration measurement (ppmv) not a rate (scf/hr).

   (27) "Leak or fugitive leak" means the unintentional release of emissions at a ~~rate~~ **<u>concentration</u>** greater than or equal to the leak thresholds specified in this article.

2. **§95668(d)(3) – Centrifugal Natural Gas Compressors**

   The Centrifugal Compressors section needs the same clarification language that was added to Section 95668(c)(4)(A) Reciprocating Compressors to prevent duplicative testing of seals.

   - §95668(d)(3) Beginning January 1, 2018, components on driver engines and compressors that use a wet seal or a dry seal shall comply with the leak detection and repair requirements specified in section 95669; **<u>except for components subject to section 95668(d)(4)</u>**; and,

   - §95669(b)**<u>(15) A compressor wet seal which is subject to the requirements specified in section 95668(d)(4) of this subarticle</u>**.

3. **Delay of Repair**
   Language was added to provide a means for extending the repair timeframe. Using "may" implies an approval is required.
   - §95668(c)(3)(D)1; §95668(c)(4)(D)1; and §95668(d)(6)(A):
     "A delay of repair ~~may~~ **<u>shall</u>** be granted by the ARB Executive Officer if the owner or operator can provide proof that the parts or equipment required to make necessary repairs have been ordered."

   - §95668(h)(4); and §95668(i)(5)
     A delay of repair ~~may~~ **<u>shall</u>** be granted by the ARB Executive Officer under the following conditions:

4. **§95669 – Leak Detection and Repair**
   - §95669(b)(1)
     Clarification is needed that LDAR is applicable to the aboveground components of wells, unless they are currently being inspected under an LDAR program. Are components currently exempt from inspection under an existing LDAR regulation exempt from this section of the proposed regulation? (ex: SCAQMD Rule 1173(l)(1)(C) "Components exclusively handling commercial natural gas.")

     - §95669(b) (1) Components, including components found on tanks, separators, **<u>the aboveground components of</u>** wells, and pressure vessels that are subject to local air district leak detection and repair **inspection** requirements if the requirements were in place prior to January 1, 2018.

- §95669(c) Beginning January 1, 2018, all components, including components found on tanks, separators, **the aboveground components of** wells, and pressure vessels not identified in section 95669(b) shall be inspected and repaired within the timeframes specified in this section.

- §95669(b)**(15)** – see #2 above

- Clarification is needed to ensure that components with no ability to produce emissions are not subject to this regulation.
  - §95669(b)**(16) Components on utilities and plant systems which do not contain natural gas: potable and non-potable water (cooling water, fire water, etc.), engine oil, cooling water, gasoline and diesel, septic and sewage systems, fire extinguishing systems, etc.**

  - §95669(b)**(17) Compressed Gas cylinders**

- §95669(e):
  The rule should clarify that personnel should not be required to drive daily to remote locations at a facility that are not otherwise visited solely for the purpose of an inspection. ARB has not demonstrated that this would cost-effectively reduce emissions and the associated accumulated vehicle emissions would greatly exceed the reduction from the occasional early detection of a very small leak. The following edits are recommended:

  - §95669(e): "Except for inaccessible or unsafe to monitor components, owners or operators shall audio-visually inspect (by hearing and by sight) all hatches, pressure-relief valves, well casings, stuffing boxes, and pump seals for leaks or indications of leaks at least once every 24 hours for ~~facilities~~ **locations** that are visited daily, or at least once per calendar week for ~~facilities~~ **locations** that are not visited at least once every 24 hours **or at least monthly if a facility has not operated more than 200 hours in a month. The operator shall keep sufficient operating records to support the inspection frequency**,"

- As written, leaks detected on a Friday could require personnel to work on the Saturday to measure the leak concentration. The very small emission rates associated with the vast majority of leaks (refer to ARB Enhanced I&M Report leak rate data) does not warrant such action. For example, ARB has not demonstrated that such a requirement would be cost-effective (i.e., considered the cost for personnel to work a weekend (possibly at over-time labor rates) relative to the difference in potential emission reductions from identifying the leak a few days faster). ARB also has not considered that the GHG emissions emitted when the personnel drove to and from work (see Attachment A). The following edits are recommended:
  - §95669(f)(1): "For leaks detected during normal business hours, the leak **concentration** measurement shall be performed ~~within 24 hours~~ **by the end of**

the next normal business day. For leaks detected after normal business hours or on a weekend or holiday, the deadline is shifted to the end of the next normal business day."

- §95669(g)(1)(A) "**The concentration of** ~~A~~**a**ll leaks detected with the use of an OGI instrument shall be measured using **U.S.** EPA **Reference** Method 21 within two calendar days of initial OGI leak detection or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component to determine compliance with the leak thresholds and repair timeframes specified in this ~~section~~ **subarticle**. **For leaks detected after normal business hours or on a weekend or holiday, the deadline is shifted to the end of the next normal business day.**"

- §95669(g)(3) Requiring inaccessible or unsafe to monitor components to be inspected per method 21 annually with no screening option could result in either placing personnel in an unsafe situation or a facility shut down. We propose adding language consistent with the CARB GHG Mandatory Reporting Rule
  - CARB GHG Section 95154
    (1) *Optical gas imaging instrument*
    (2) *Method 21* "Owners or operators must use alternative leak detection devices as described in paragraph (a)(1) or (a)(2) of this section to monitor inaccessible equipment leaks or vented emissions."
    (4) Optical gas imaging instrument. An optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.
  - §95669(g)(~~3~~**2**) All inaccessible or unsafe to monitor components shall be inspected at least once annually using US EPA Reference Method 21 **or screened with Optical Gas Imaging instruments**.
- The ARB Notice of Public Availability indicates that "scheduled" was added to Section 95669(h)(3) ,Table 2 and Table 4, but it is missing from 95669(h)(3). For consistency, "scheduled" should also be added to section 95669(i)(4)
  - 95669(h)(3) Critical components or critical process units shall be successfully repaired by the end of the next **scheduled** process shutdown or within 12 months from the date of initial leak detection, whichever is sooner.
  - 95669(i)(4) Critical components or critical process units shall be successfully repaired by the end of the next process **scheduled** shutdown or within 12 months from the date of initial leak detection, whichever is sooner.
- A best practice proposed by the CPUC in the SB 1371 Leak Abatement OIR proceeding is to "require bundling of work whenever possible to prevent multiple venting of the same piping". Rule language is needed to prevent a conflict between regulatory proceedings. During discussions with ARB staff, the question of when a shut-in or blowdown is necessary was discussed. Safety of personnel and the public are of primary concern. If repairs are required on high pressure systems, it is unsafe to perform even a

simple task such as tightening a flange without first reducing the pressure. An analogy would be adjusting a fitting on a garden hose (low pressure water) vs. a fire hose (high pressure).

- 95669(h)(4)**(C) A delay of repair will result in a net decrease in emissions when consideration is given to bundling the repair with other, planned future work. The owner or operator can provide documentation of the planned future work to support the consideration of net emissions benefit.**

  1. The delay of repair shall not exceed the end of the next scheduled process shutdown or within six months, whichever is sooner.

- 95669(h) and 95669 (i) Previous comments have been submitted regarding the technical basis for Table 1 and Table 3. Originally this table was referenced as an incentive to step-down from a required quarterly inspection to annual. With the removal of the step-down inspection frequency, these tables and associated references should be deleted.
  - ~~**Table 1 - Allowable Number of Leaks**~~

~~**January 1, 2018 through December 31, 2019 Leak Threshold**~~	~~**200 or Less Components**~~	~~**More than 200 Components**~~
~~10,000-49,999 ppmv~~	~~5~~	~~2% of total inspected~~
~~50,000 ppmv or greater~~	~~2~~	~~1% of total inspected~~

  - ~~**Table 3 - Allowable Number of Leaks**~~

~~**On or After January 1, 2020 Leak Threshold**~~	~~**200 or Less Components**~~	~~**More than 200 Components**~~
~~1,000-9,999 ppmv~~	~~5~~	~~2% of total inspected~~
~~10,000-49,999 ppmv~~	~~2~~	~~1% of total inspected~~
~~50,000 ppmv or greater~~	~~0~~	~~0~~

- 95669(o) The sections limiting the number of leaks should be deleted. Studies, including the ARB Enhanced I&M Report, have shown that a leak concentration measured by EPA Reference Method 21 is a very poor predictor of the leak's mass flow rate. Further, as discussed below, the sections limiting the number of leaks imply that leaks can be prevented, which is inconsistent with a basic, common understanding of leak emissions and LDAR program objectives.
  - ~~(1) Between January 1, 2018 and December 31, 2019, no facility shall exceed the number of allowable leaks specified in Table 1 during any an ARB Executive Officer inspection period as determined by the ARB Executive Officer or by the facility owner or operator in accordance with US EPA Reference Method 21, excluding the use of PID instruments.~~
  - ~~(2) On or after January 1, 2020, no facility shall exceed the number of allowable leaks specified in Table 3 during any an ARB Executive Officer inspection period as determined by the ARB Executive Officer or by the facility owner or operator~~

~~in accordance with US EPA Reference Method 21, excluding the use of PID instruments.~~

- 95669(o)(5) The notice of public availability states that this section is necessary to ensure that facilities are maintained in compliance with the standards. This is inconsistent with the objective of LDAR programs, where leak surveys are intended to discover and repair leaks. If leaks did not occur over time, repairs could be completed once and no further actions would be required. LDAR requires periodic leak surveys because leaks in pressurized systems will occur regardless of operator diligence – e.g., due to thermal cycling, vibration, etc. associated with typical operations of the affected components. This section implies that all leaks can be prevented, which is inconsistent with a basic, common understanding of leak emissions and LDAR program objectives, therefore this section should be deleted.
    - 95669(o~~)(5) Except for the fourth (4th) quarterly inspection of each calendar year, leaks discovered during an operator conducted inspection shall not constitute a violation if the leaking components are repaired within the timeframes specified in this subarticle~~

5. **95671(f)(1)(b) Vapor Collection Systems and Vapor Control Devices.**
For consistency and to reduce potential conflict with other section of this regulation, the delay of repair language should be added to this section. This allows for instances where additional time may be required to address technical and safety issues, long lead times, or to obtain permits.

§**95671(f)(1)(b)** **<u>A delay of repair shall be granted by the ARB Executive Officer if the owner or operator can provide proof that the parts or equipment required to make necessary repairs have been ordered.</u>**

<u>*i*. A delay of repair to obtain parts or equipment shall not exceed 30 calendar days, or 60 days from the date from of the initial measurement, unless the owner or operator notifies the ARB Executive Officer to report the delay and provides an estimated time by which the repairs will be completed.</u>

6. **§95673- Reporting Requirements**

- §95669 (9): The reporting requirement to report an alarm 4 times the baseline conditions (8 ppm if 2 ppm is baseline) does not take into account any time weighted integrated average (such as a 20 minute average).
- This alarm limit does not consider if it is a leak from the facility versus external sources (e.g., biogenic or other sources).
- Alarm reporting should be revised to only include those incidents confirmed to be from the facility and should be based on a defined averaging period rather than an instantaneous measurement, which could be caused by any number of perturbations.

7. **Appendix C**

- Appendix C Test Procedure for Determining Annual Flash Emission Rate of Gaseous Compounds from Crude Oil, Condensate, and Produced Water, §10.3: The bubble point pressure and sample integrity check is flawed:
    - Transferring the sample from a floating piston cylinder to a double valve cylinder may compromise the sample (e.g., loss of volatile hydrocarbons and/or addition of air). Further, water-soluble species (e.g. CO_2, methane) could be transferred from the hydrocarbon phase in the double valve cylinder.
    - The graphing procedure in sub-section (g) appears to assume the bubble point pressure is the same or very close to the sample collection pressure. If the actual bubble point pressure is much less than or much greater than the sample collection pressure, then all six data points could be in a straight line. Or, the bubble point pressure could be between two of the three pressures below or above the sample collection pressure.