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SENT VIA EMAIL

May 15, 2015

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

Re: SCG and SDGE Comments on Draft Regulation Proposal for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities

Dear Mr. Fischer:

On behalf of the Southern California Gas Company (SCG) and San Diego Gas & Electric (SDGE), the following comments are respectfully submitted in response to the California Air Resources Board (CARB) Public Workshop on April 27, 2015. The Workshop provided industry and interested stakeholders an opportunity to hear staff's presentation of the Draft Regulation Proposal for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. Our comments on the proposed regulation are formatted as follows:

- Cover Letter / General Overview
- Attachment
  - Regulation Comments by Section
  - Expanded General Comments and Supporting Information

GENERAL OVERVIEW

The following provides an overview of our comments on the regulation. Further details and supporting data are provided as appropriate in each section of the proposed regulation.

Exemption for Publicly Regulated Natural Gas Utilities

We request that an exemption for Publicly Regulated Utilities from the proposed regulation be provided. 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 transport and to "withdraw" previously stored gas to meet customer needs. As such, natural gas underground storage and transmission station operations are critical to the utility's ability to reliably supply the markets at times of varying demand in the regions where services are provided. The CPUC is currently developing a rule based on recent legislation - SB 1371 (Leno) Natural gas: leakage abatement, for reducing methane releases which includes source categories covered by the proposed regulation. Therefore we propose that Essential Public Services be exempt from the rule, so as to reduce regulatory conflict and to ensure system availability. We also propose that CARB delay this rule making until the CPUC has completed its rule as the CPUC approval process requires different regulatory mechanisms than used by CARB and local air districts.

At a minimum, additional rule language that exempts underground storage and Transmission facilities from, or provides greater flexibility with regard to the prescriptive leak repair time periods is strongly suggested. We would like to meet with the appropriate staff to provide more information about our gas transmission and storage operations, how they support energy reliability for our customers, and the critical timing needs that are involved. We are confident that the need for safe and reliable gas delivery to our customers can be balanced with the necessity to further reduce methane emissions. We look forward to working with you to achieve both objectives.

Balancing Operational and Safety Demands

As Publicly regulated Natural gas utilities, we are required to obtain approval from the CPUC for capital infrastructure improvements. With this in mind, the proposed regulation should seek to balance critical operational, cost and safety demands with timely leak repair activities. Utilities should be provided the flexibility to prioritize the timing for leak repairs based on leak size as well as potential hazard level of the leak. Further, if the repair of smaller non-hazardous leaks could impact overall system reliability the leak repair priority should be adjusted accordingly. This is especially true for "smaller" leaks where the procurement of replacement components is costly or may require extensive lead time that affects critical services.

As an example of this need for balance, excerpts from SB1371 (Leno) Natural Gas Leakage Abatement, contains language that addresses 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…"

Cost Effectiveness Evaluation
CARB should provide its environmental analysis, including cost-benefit analysis, to support applicability thresholds and control requirements as soon as is practical. The rule development process should include analysis to justify regulatory requirements. Information presented at the April 27 workshop did not include a cost effectiveness analysis for industry review. The regulation requirements for new or additional control systems, testing, monitoring and repairs by facilities cannot be carried out without regard for the financial impacts. More specifically, many of the requirements in the proposed regulation will require capital improvements that must be approved by California Public Utilities Commission (CPUC). Additional comments will be provided once the Environmental Analysis Report and Cost-Benefit analysis is available.

Harmony with APCD Leak Detection and Repair (LDAR) Requirements
The proposed regulation seeks to merge new methane Leak Detection and Repair (LDAR) activities with existing local agency LDAR programs for VOC emissions. However, it has not been established that regulatory parallels for VOC rules are appropriate for GHG / methane reductions. Once again, the cost effectiveness of using an LDAR program to control methane has not been presented by CARB. In addition, local air districts have been tasked with approving requests for identification of critical components, leak repair extensions, and with the new criteria processing new permit applications. An alternate approval process should be provided or additional time to implement to allow local air districts to establish new programs or processes where needed.

Thank you in advance for your careful consideration of this request.

Sincerely,

Charles Humphrey

Charles Humphrey

Cc: Jim Nyarady, CARB
Jill Tracy, SoCalGas
Jerilyn Mendoza, SoCalGas
Darrell Johnson, SoCalGas
Jill Tracy, SoCalGas

<u>Attachment</u>
Proposed Regulation Review (by section)

§ 95212. Definitions
The proposed rule includes many definitions that differ from definitions in existing oil and gas industry GHG rules including the CARB Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, 40 CFR 60 Subpart OOOO, and 40 CFR 98 Subpart W (the EPA GHG Reporting Program). Introducing new definitions is not necessary and likely counter-productive and confusing for owners and operators currently complying with existing rules. Whenever possible, existing definitions consistent with current practices and requirements should be adopted for the new rule.

The following definitions should be either clarified in the regulation or amended as indicated. In select cases, suggested rule text revisions are provided with deleted text indicated by ~~strike-through~~ and added text indicated by <u>**bold underline**</u>

The <u>definition for "component" should not include reciprocating compressor rod packing or seals on units with less than 500 rated horsepower.</u> The definition of component is used to identify equipment subject to leak detection and repair requirements, and gas emitted from a reciprocating compressor rod packing should be considered a vented emission, not a leak emission, because some emissions through the rod packing is expected as part of normal operation

> 95212(a)(8) "Component" means a valve, fitting, flange, threaded-connection, process drain, stuffing box, pressure relief valve, pipe, seal fluid system, diaphragm, hatch, sight-glass, <u>**or a**</u> meter. ~~, or a reciprocating compressor rod packing or seal on units with less than 500 rated horsepower~~

The definition of "**emissions**" should be revised to specify "greenhouse gases" only as that is the contaminant of concern and the focus of the regulation as noted in Section 95210 Purpose and Scope, e.g. the establishment "of greenhouse gas emission standards for crude oil and natural gas facilities." There are existing local, state and federal regulations that already regulate the other compounds noted in the current proposed definition.

§ 95212(a)(11) "Emissions" means the release of greenhouse gases, ~~volatile organic compounds, toxic air contaminants, or other hydrocarbon gases~~ into the atmosphere

The definition for "**Natural gas transmission compressor station**" should clarify that rule requirements only apply to equipment inside the fence line at a natural gas transmission facility and a transmission facility does not include gathering pipelines.

> § 95212 (a)(24) "Natural gas transmission compressor station" means all facility equipment and components <u>**located within the facility fence line**</u> associated with moving natural gas from production fields or natural gas processing plants through

> natural gas transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage. **<u>This does not include gathering pipelines</u>**.

The term "**natural gas well**" should be defined separately as it is not clear if the term refers to natural gas production or a storage/withdrawal well located at an underground storage facility.

> § 95212 (a)(33) Primary vessel means the first vessel that receives crude oil, condensate, produced water, natural gas, or emulsion from one or more crude oil or **natural gas well** and allows emissions to flash from the liquids to a headspace or to the atmosphere.

The definition for "production" should differentiate natural gas <u>production</u> from natural gas <u>withdrawal</u> from a storage field. According to the United States Energy Information Administration, the description for "production" includes the following language:

"Volumes of gas withdrawn from gas storage reservoirs and native gas, which has been transferred to the storage category, are not considered production…"

> § 95212(a)(35) "Production" means all activities associated with the production or recovery of crude oil, condensate, or natural gas and includes well stimulation treatments. **<u>This definition excludes natural gas withdrawal from an underground storage facility</u>**.

Clarify definitions for primary and secondary vessels; the definition for **<u>"Secondary vessel</u>**" should clearly consider multiple stages of separation.

> § 95212(a)(42) "Secondary vessel" means any vessel that receives crude oil, condensate, produced water, natural gas, or emulsion from a primary vessel or a secondary vessel and allows emissions to flash from the liquids to a headspace or to the atmosphere. There may be more than one secondary vessel **<u>involved</u>** in a separation **<u>process</u>** and tank system."

The definition for a "sump" has its own entry and therefore should not be included in the definition for a vessel. Also, vessels that are manually drained should be excluded from the definition because emissions are minimal. For example, manually drained liquid separators at natural gas compressor stations have a capped connection that is only opened when the separator is drained into barrels. The transfer of liquid is stopped when the vessel is near empty, and the connection is recapped. It should not be necessary to conduct flash tests on vessels that clearly have low enough throughput to support manual draining.

> § 95212 (a)(45) "Sump" means a lined or unlined surface impoundment or depression in the ground that, during normal operations, is used to separate or store emulsions of crude oil, condensate, natural gas, or produced water

§ 95212 (a)(51) "Vessel" means, for the purpose of this article, any tank, or separator, ~~or sump~~ used to separate, store, or circulate emulsion, natural gas, crude oil, condensate, or produced water**, except vessels that are manually drained**.

A separate definition should be provided for the term "**underground injection well**" to clarify if it refers to natural gas injection into a underground storage zone. Also, the definition for well stimulation should be clarified to differentiate between production and underground storage wells.

§ 95212 (47) "Vapor collection system" means equipment and components installed on vessels including piping, connections, and flow-inducing devices used to collect and route emissions to a processing, sales gas, or fuel gas system; to an **underground injection well**; or to a vapor control device.

§ 95212 (52) "**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 underground crude oil or natural gas reservoir. Examples include hydraulic fracturing, acid fracturing, and acid matrix stimulation. **Treatments used for routine maintenance of wells associated with underground storage facilities where natural gas is injected into and withdrawn from depleted or partially depleted oil or gas reservoirs are not included in this definition.**

§ 95213 (a) Primary and Secondary Vessels

Section 95213(a)(1) should clarify that pressurized liquids sampling and vapor control requirements only apply to vessels without a vapor collection system.

"Owners or operators of crude oil, condensate, or produced water vessels without a vapor collection system installed on **any** ~~the~~ primary ~~and~~ **or** secondary vessel~~s~~ shall install a vapor collection system on the primary and secondary vessels **without a vapor collection system** as described in section 95213(c) or perform the following:" [§ 95213(a)(1)]

Pressurized liquids sampling requirements should account for a series of separation stages.

"Flash analysis testing is required at each primary **or secondary** vessel **immediately upstream of any vessel that allows emissions to flash from the liquids to the atmosphere**. Additional flash analysis testing may be conducted and the results averaged in order to determine representative testing." [§ 95213(a)(1)(A)2]

The reference to "section 95213(a)(1)(B)1" in § 95213(a)(1)(A)3] does not appear to be correct.

"Sum the annual emission rates of methane as determined in section 95213(a)(1)(B)1 for the crude oil, condensate, and produced water." [§ 95213(a)(1)(A)3]

"Section 95213(a)(1)(B)(3)" referenced in § 95213(a)(1)(B) does not exist and it should be clear that the 10 tpy methane threshold only applies to vessels without a vapor collection system.

> "Owners or operators of primary and secondary vessels **without a vapor collection system** with a measured annual emission rate greater than 10 metric tons per year of methane as determined in section 95213(a)(1)(B)(3) shall control the primary and secondary vessels **without a vapor collection system** as follows:" [**§** 95213(a)(1)(B)]

§ 95213 (c) Vapor Collection Systems
Language should be included to explicitly indicate that existing vapor recovery, vapor collection and/or vapor control systems including flares and thermal oxidizers, which are permitted by local Air Districts and designed to control VOC emissions from primary and/or secondary tanks and tank systems shall be deemed to meet the requirements of this subparagraph. Additionally, language to exclude vapor control systems for transmission pipeline compressor stations should be added. Requiring vapor control systems for these operations is infeasible due to their intermittent operations and the predominance of high pressure lines for gas compression. Underground storage field operations have various lower pressure systems in which to direct or collect gas vapors; however this is not the case at a compressor station. Collection of lower pressure gas is simply not cost effective or practical.

§ 95213(a)(1)(B)(3) referenced in § 95213(a)(1)(C) does not exist.

The proposed language should differentiate between existing permitted control devices covering the vapors they are regulating, vs. piping for new vapor streams to devices which may exceed their capacity. That is, if an existing permitted system is in place, the regulation should not require it to be changed or modified unless operations are changed.

§ 95213(a)(1)(C)2 should only apply to vessels without a vapor collection system, and an increase in natural gas throughput should not trigger re-testing. The only likely scenario for an increase in natural gas production without a corresponding increase in crude oil or condensate production would be due to a lower separator operating pressure. For example, a reduction in gathering pipeline pressure would allow lower separator operating pressures and increased natural gas production. The lower separator operating pressure would reduce storage tank flash gas emissions.

> "Flash analysis testing and reporting shall be conducted at any time the annual crude oil or condensate natural gas throughput of the primary and secondary vessels without a vapor collection system increases by more than ten (10) percent since the most recent flash analysis testing and reporting." [§ 95213(a)(1)(C)2]

§ 95213(c)(1) The vapor collection system shall direct the collected vapors to one of the following types of existing equipment or processes installed at the operation:

(A) Sales gas system; or,
(B) Fuel gas system; or
(C) Underground injection well; or,
(D) **Existing permitted vapor control device, with no additional sources of vapors**

§ 95213(c)(4) Applying a 95% “vapor control efficiency” needs to be better defined. As discussed earlier in these comments, “emissions” for the purpose of this article should be greenhouse gas emissions. **To better define performance criteria and testing, “95% vapor control efficiency” should be changed to “95% methane control efficiency” throughout this section.**

§ 95213(c)(4)(B) As discussed in rule workshops, flaring or thermal oxidation which results in NOx emissions may be necessary where vapor constituents or air entrainment (oxygen) make the vapor unsuitable for collection and reuse. Also, it is unlikely that any flare or thermal oxidizer will be able to operate without supplemental fuel gas in order to assure adequate temperature and to account for flow variations.

We request that facilities be able to use an alternate permitted control device with no penalty in the event that the existing system needs to be temporarily taken out of service. This is consistent with some local air district permit requirements for vapor recovery systems.

§ 95213(c)(5) Vapor collection systems are allowed up to 14 calendar days per year for equipment breakdowns or maintenance provided that the local air district is notified within one (1) hour of the discovery of a system malfunction or if the system is intended to be taken out of service for scheduled maintenance. **If an Alternate Permitted Control Device (APCD) is installed prior to the maintenance shut-down, the event duration does not count toward the 14 day limit and the notification requirement is not needed.**

§ 95213 (d) Reciprocating Natural Gas Compressors at or Below 500 Rated Horsepower

The rule requirements for reciprocating compressors rated at or below 500 hp should not be more stringent than requirements for reciprocating compressors rated greater than 500 hp; however, the draft proposed rule requirements for compressors rated < 500 hp are more stringent than requirements for units > 500 hp as shown in Table 1. The smaller compressors require more frequent monitoring, shorter repair or remove from service times, and, as the data presented below demonstrate, have an emission rate threshold that is effectively an order of magnitude or more lower than units rated > 500 hp.

Table 1. Draft Proposed Rule Requirements for Reciprocating Compressors.

Rule Requirement	Reciprocating Compressor Rating	
	≤ 500 hp	> 500 hp
Rod packing vent rate monitoring frequency	Quarterly	Annual
Rod packing repair threshold emission “rate”	> 1,000 ppmv THC by M21	> 2 scfm
Repair or remove from service timeline	2 – 7 calendar days	14 calendar days

CEC/CSUF measured leak concentrations and associated leak rates at natural gas facilities[1].

Table 2 summarizes this information and shows that all leaks with a Method 21 concentration less than 50,000 ppmv had a leak rate less than 2 scfm. Further, the average leak rates for all Method 21 leak concentration ranges are a fraction of 2 scfm as shown in the fifth column.

Table 2. CSUF Natural Gas Systems Leak Data.

Method 21 Leak Concentration (ppmv)	Leaks Detected	Leak Rate (cfm)			Avg / 2 cfm	lb CH4/ day[A]	lb CO2e/ day[B]
		Max	Min	Avg			
0 to 999	16	0.005	0.005	0.005	0.0025	0.30	7.6
1,000 to 9,999	108	0.410	0.005	0.029	0.015	1.8	44
10,000 to 49,999	109	1.640	0.005	0.071	0.036	4.3	110
50,000+	205	8.850	0.005	0.489	0.24	30	740
Total	438	8.850	0.005	0.256	0.13	16	390

A. Based on average leak rate and assumes 100% of leaked gas is methane

B. Based on average leak rate, assumption that 100% of leaked gas is methane, and methane global warming potential (GWP) of 25

The low leak rates determined by these measurement data are consistent with studies completed by EPA, the Gas Research Institute (GRI) and others. Figure 1 plots measured leak rate data from EPA against associated Method 21 screening values, and shows a correlation equation developed to estimate emissions from screening data. Table 3 summarizes leak rate estimates based on this correlation equation. The leak rates are one to two orders of magnitude lower than

[1] *Estimation of Methane Emission from the California Natural Gas System*, prepared for the California Energy Commission (CEC) by California State University, Fullerton (CSUF), 2012

measured by the CSUF study.

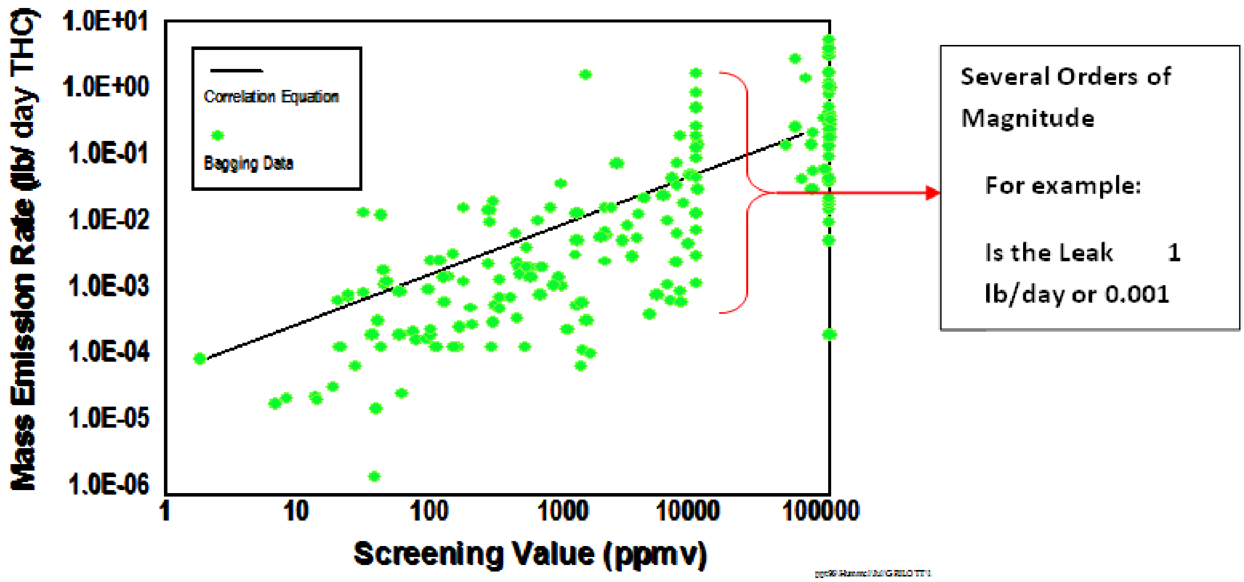

Table 3. EPA Natural Gas Systems Leak Data.

Method 21 Screening Value (ppmv)	Leak Rate (cfm as CH4)[A]	Avg / 2 cfm	lb CH4/ day[B]	lb CO2e/ day[C]
1,000	0.0002	0.00008	0.01	0.25
10,000	0.0007	0.00033	0.04	1
100,000	0.005	0.0025	0.3	7.5

A. Based on lb/hr leak rate and assumes 100% of leaked gas is methane

B. Estimated from Figure 1 correlation equation and assumes 100% of leaked gas is methane

C. Based on average leak rate, assumption that 100% of leaked gas is methane, and methane global warming potential (GWP) of 25

Because rod packings vent slightly by design[2], many Method 21 rod packing vent concentration measurements may be greater than 1,000 ppmv and the draft proposed rule Method 21 monitoring schedule would result in quarterly rod packing "repairs" for covered compressors. This requirement will most likely be a de facto requirement to install a vapor recovery system on all reciprocating compressors rated less than 500 hp in accordance with §95213(d)(1). The cost-effectiveness of this monitoring and repair schedule should analyzed before the final proposed rule to justify these requirements, or more cost-effective rule requirements should be developed. In addition, the cost-effectiveness of installing vapor recovery systems on reciprocating compressors rated less than 500 hp should be determined to justify this control requirement, or more cost-effective rule requirements should be developed. At a minimum, rule requirements

[2] " All packing systems leak under normal conditions" EPA Natural Gas STAR Partners Lessons Learned "Reducing Methane Emissions From Compressor Rod Packing Systems." http://epa.gov/outreach/gasstar/documents/ll_rodpack.pdf

for reciprocating compressors rated less than 500 hp should not be more stringent than the requirements for larger compressors, and a leak rate of 2 scfm is recommended regardless of size. As noted in comments above, CARB should justify the requirements included in the proposed rule, and it is unlikely that the repair decisions for rod packing venting based on Method 21 concentration measurements would be reasonable.

§ 95213 (e) Reciprocating Natural Gas Compressors over 500 Rated Horsepower

For compressors with multiple cylinders and manifolded rod packing vents, and a safe access port for rod packing measurements downstream of the location where multiple vent lines are co-mingled (e.g., sample ports installed for Subpart W and/or CARB GHG reporting rule measurements), the rule should have an option to measure emissions from the manifolded lines rather than requiring vent line modifications to allow individual rod packing measurements.

SoCalGas and SDG&E compressors typically cycle off-and-on to meet customer demands. Even if a compressor is off, its availability might be critical to assure natural gas reaches the customer in the next hour, day, week, or month. To minimize the possibility of curtailing natural gas supplies to customers, the critical component criteria applicable to LDAR in § 95213(i)(3)(D) should also be applicable to packing and seals.

Suggested rule text revisions:

> § 95213(e)(1) Each compressor shall collect the rod packing or seal vent gas with a vapor collection system and route the collected gas to an existing sales gas system, fuel gas system, or vapor control device; or,
>
> § 95213(e)(2) Each compressor shall provide a clearly identified access port for making individual rod packing or seal emission flow rate measurements **or an access port for manifolded vent lines from more than one rod packing or seal**; and,
>
> § 95213(e)(3) Each individual compressor rod packing or seal shall be measured annually during **while the compressor is operating** to determine the rod packing or seal emission flow rate determined by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument); **or manifolded compressor rod packing or seal vents shall be measured annually during normal operation to determine the rod packing or seal emission flow rate determined by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument)**; and,
>
> § 95213(e) (4) An individual rod packing or seal with a measured emission flow rate greater than two (2) standard cubic feet per minute **(scfm)** shall be successfully repaired or the unit removed from service within 14 calendar days unless a more stringent flow rate or more stringent repair time is required by the local air district**; or if the measured emission flow rate from manifolded compressor rod packing or seal vent lines is greater than the number of manifolded vent lines multiplied by 2 scfm, then rod packing or seals shall be successfully repaired such that a re-measurement of the manifolded lines emission flow rate is less than the number of manifolded vent lines multiplied by 2 scfm or the**

unit shall be removed from service within 14 calendar days unless a more stringent flow rate or more stringent repair time is required by the local air district. A time extension not to exceed 14 calendar days may be granted by ARB or the local air district."

§ 95213(e) (4) Packing found leaking above the 2 scfm threshold that are technically infeasible to repair without a process unit shutdown or to maintain compressor availability, parts are unavailable, or for other good cause, shall be repaired within 12 months from the date the emissions are found over the threshold.

§ 95213 (f) Centrifugal Natural Gas Compressors

The rule language should provide exemptions in cases where physical limitations and challenges exist related to installing dry seals on certain vintage centrifugal natural gas compressors. This exemption shall be granted based on a demonstration by the operator and approved by the local Air District.

SoCalGas and SDG&E operate ten centrifugal compressors equipped with wet seals:

> Four of these centrifugal compressors are small and have seals that emit less than 1 scfh which is less than many dry seals; retrofit should not be required.
>
> Three of these centrifugal compressors have not operated for over a decade, other than one station that is test fired. Without any operation, it will not be cost effective to retrofit with dry seals.
>
> One of these centrifugal compressors in a pipeline application does operate a few thousand hours a year, but rarely over 4000 hours. The compressor is a 1970's vintage Clark compressor. Manufacturer and other vendors were queried for a solution. It was found that a dry seal retrofit would cost between $750,000 and $1,000,000 without guarantee of effectiveness. The existing compressor frame is not large enough to accommodate a traditional dry seal. As an alternative, we have explored the possibility of recovering the vented gas into the turbines fuel supply. BP has demonstrated such a system that recovers nearly 100% of the gas. Some venting will be required, especially during turbine start-up, and shut-down. Cost is estimated to be about $50,000, so a project has already been initiated to demonstrate this idea.
>
> Three centrifugal compressors in a storage application are scheduled to be replaced with new compressors equipped with dry seals. Although the new compressors are scheduled to be in service by late 2016, the existing compressors with wet seals will not be taken out of service until three years after the new units become operational to assure availability of the storage field.

While emissions from wet seals can be quite high, the rule should take a flexible approach due to the extremely small population and unique challenges that are associated with them. It should also be recognized that flaring or thermal oxidation may be the only practical means of reducing these emissions.

§ 95213 (g) Pneumatic Devices and Pumps

The control requirements in § 95213(g)(1) and § 95213(g)(3) (i.e., vapor control system or compressed air operation) may not be economically feasible at remote locations. The cost-effectiveness of these control requirements should be demonstrated or the control requirements revised prior to publishing the final draft proposed rule. The EPA Natural Gas STAR program provides guidance on cost-effective instrument air systems.

§ 95213 (i) Leak Detection and Repair

At workshops for the proposed rule, several attendees commented that the minimum threshold for repair should be lowered from 1000 to 500 ppm. However, there is no technical basis for this. Presumably, a criterion for VOC was extended to methane; but this is not appropriate because the concentration of methane is higher in the sample matrix. Method 21 sampling rate will pull in more methane than diluted VOCs. Based on data collected under a California Energy Commission Project by California State University Fullerton (CSUF), 50,000 ppm would be an appropriate minimum threshold. Although there were some concerns with the emission factors calculated in study, the concentration and flow rate measurements taken by CSUF are representative of actual leaks in California gas systems. The report provides many graphs that show no correlation of concentration vs. flow. In the CSUF report, Figure 5.2.1.1 provides a graph off all the concentration vs. flow data, and Table 5.2.1.2 parses the data into specific ranges based on concentration. This figure and table are copied below.

Figure 5.2.1.1: Leak Rates vs. Screening Values of All Leaking Components

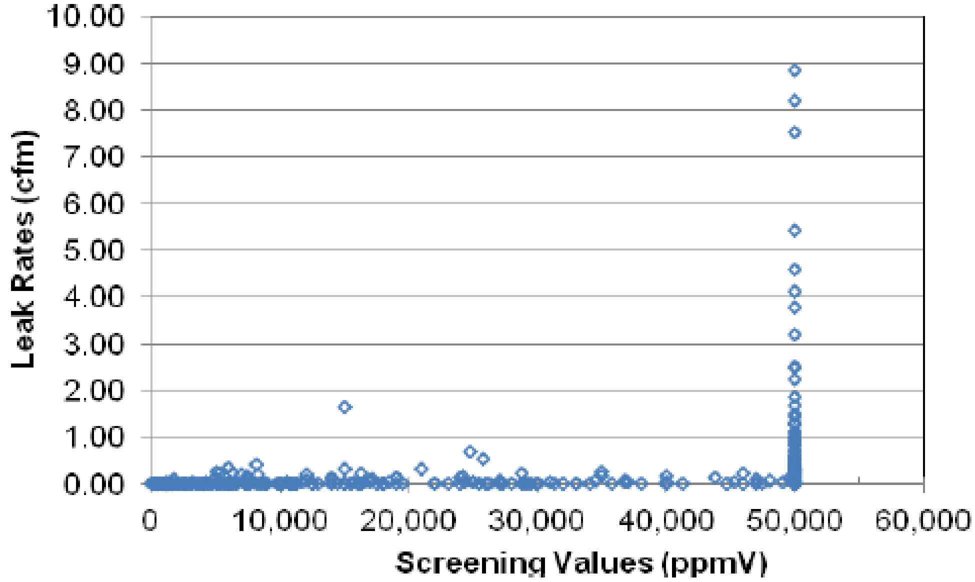

Table 5.2.1.2: Leak Rates vs. Screening Values in Four Ranges (All Components)

		Leak Rate (cfm)				
SV (ppmV)	Count	Min	Max	Median	Average	Geomean
100-999	16	0.005	0.005	0.005	0.005	0.0050
1,000-9,999	101	0.005	0.410	0.005	0.027	0.0085
10,000-49,999	94	0.005	1.640	0.020	0.070	0.0198
≥50,000	167	0.005	8.850	0.110	0.552	0.0901
Total	378	0.005	8.850	0.010	0.269	0.0291

In the spreadsheet below, the Counts in Figure 5.2.1.2 are multiplied by the average leak rate to calculate the total leak for each range of concentrations. An 89% reduction would be realized with a threshold of 50,000 ppm. Selecting 10,000 ppm as the minimum threshold would result in 96% reduction. By going down to 1000 ppm, you only pick up an additional 3% reduction. Dropping further to 500 ppm as proposed by some at the workshops, results in far less than 1% additional reduction. It is unlikely that repairing leaks below 10,000 ppm, let alone 1000 ppm are cost effective. The threshold for repair should be set no lower than 10,000 ppm.

SV (ppmv)	Count	Avg cfm	Total cfm for all leaks	Percent of leakage
0 to 999	16	0.005	0.08	0%
1,000 to 9,999	108	0.029	3.13	3%
10,000 to 49,999	109	0.071	7.74	7%
50,000+	205	0.489	100.25	89%
Total	438	0.256	112.13	100%

Just as the minimum threshold for leak repairs do not clearly demonstrate environmental benefit (especially if lowered from 1000 to 500 ppm), the timing for repairs too is not consistent with environmental benefit; longer timeframes are warranted especially in light of the regulatory obligations imposed by the CPUC on Transmission and Storage facilities. Allowance should be made for conditions where repair cannot be performed within the prescribed window due to part unavailability.

Unsafe to monitor components are a concern, in support of their exemption from the leak detection and repair requirements of this rule, examples are provided.

> § 95213(i)(1)(F) Components which are unsafe to monitor when conducting EPA Method 21(40CFR 60, Appendix A) measurements and as documented in a safety manual or policy ~~and~~ **or with** approval of the local air district.
>
> § 95213(i)(1)**(G) Instruments designed to analyze and/or monitor natural gas parameters. i.e. moisture content, quality, or odor intensity.**

Section (2) Detection

Section 95218 allows for local air districts to implement more stringent requirements, therefore, we recommend removing the redundant verbiage as follows:

> 95213(i)(2)Except as provided in section 95213(i)(1), components containing natural gas in sources categories listed in section 95211 shall be inspected according to one of the following methods and at the frequency specified ~~unless other monitoring methods or a more stringent inspection time period is required by the local air district~~:

Additionally, at a minimum, less frequent monitoring should be allowed similar to what some local rules (e.g. South Coast Air Quality Management District Rule 1110.2) allow if initial monitoring demonstrates consistent performance.

It should also be noted that not all components at a facility can be safely accessed for routine leak testing without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring. The following pictures provide examples of unsafe to monitor sources.


JLG LIFT
JLG

§ 95213(i)(2) requires annual leak detection surveys if Method 21 is used to detect leaks but quarterly surveys if an optical gas imaging instrument is used to detect leaks. Other regulations requiring leak detection, including the CARB Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (refer to § 95153(o) and § 95154(a)), Colorado Regulation 7 (refer to § XVII.F), and 40 CFR 98 Subpart W (refer to §98.233(q) and §98.234(a)), consider these methods to be equivalent for detecting leaks. The rule should require annual surveys using either Method 21 or optical gas imaging instrument, or CARB should provide data justifying the need for and cost-effectiveness of more frequent optical gas imaging instrument surveys.

§ 95213(i)(3)(A)-(C) stipulates very short timelines for repairing component leaks or removing equipment from service after leak detection. The cost-effectiveness of these repair schedules should be analyzed before the final proposed rule to justify these requirements, or more cost-effective rule requirements should be developed. Further, all timelines should be expressed as working or business days.

§ 95213(i)(3)(D) Critical components found above the minor leak threshold and that are technically infeasible to repair without a process unit shutdown, **parts are unavailable, or for other good cause** or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair, shall be repaired to minimize leakage to the maximum extent possible within ~~one (1) hour~~ **5 business days** of detection and the repair of such components shall be completed by the end of the next process shutdown or within 12 months from the date of initial leak detection, whichever is sooner.

The term "leak free" in § 95213(i)(4) should be defined; for example, a "leak free" component has a Method 21 measured leak concentration less than or equal to 1,000 ppmv (i.e., below the minor leak threshold).

§ 95214. Record Keeping Requirements

No comments

§ 95215. Reporting Requirements

Section 95215 Reporting Requirements specifies that items (a) and (b) under Section 95215 be reported to the ARB in the time frames specified. However, it is noted in Section 95216 Implementation that local air districts may enforce the requirements of this regulation and that local air districts could impose more stringent requirements (which would likely require additional recordkeeping and reporting requirements.

Reporting to both local air districts (SoCalGas could be required to report to as many as 9 local air districts) and CARB would be duplicative. SoCalGas requests that where an entity is required to report to a local air district in regard to this regulation, that the air district forward ARB required data to the ARB rather than the regulated entity having to prepare separate reports. ARB would benefit as each local air district could submit one filing that would include data from all regulated entities in their jurisdiction rather than have all the individual entities submit separate reports.

§ 95216. Implementation

Section 95216 Implementation, (b)(1) Local Air District Permitting Requirements, requires owners/operators of existing affected facilities to revise their permits to ensure that all equipment is in compliance with this regulation. Further, this section specifies that these permits be revised by "the next air district permit renewal date for the facility." Under (b)(1)(D) facilities affected by a rule amendment get two (2) years to revise their permits. In most air districts, permits are renewed annually. This would mean that regulated entities would likely have to obtain permit revisions within one year, and likely less than one year. While Title V permitted facilities have a 5 year renewal period, an entity could be within a year or less of their renewal date and could also have difficulty in getting the permit revised in time. Especially if one considers the Title V permitting process that include public and USEPA review.

We request that ARB specify at least a 2 year permit revision deadline similar to what newly affected facilities have in Section (b)(1)(D). Further, we encourage ARB to consult with the local air districts and discuss potential permit revision impacts and time frames.

Appendix A

Definitions in Appendix A Section 3 should be the same as definitions in § 95212 of the rule
The rule should clarify whether gas-to-oil ratios (GOR) and gas-to-water ratios (GWR) are calculated using the pre-flash or post-flash liquid volume.

Is the definition of "Flash" intended to apply to any gas that volatizes from solution when a process pressure drop occurs (e.g., when liquids drop from well pressure to primary separator pressure) or when gas that volatizes from solution during process pressure drop has the potential to vent to atmosphere (e.g., when separator liquids are dumped to an atmospheric storage tank)? The latter is more typical of industry nomenclature.

The definition of Pressurized primary separator requires revision.
3.16 "Pressurized primary separator" means the first vessel that receives crude oil, condensate, or produced water from one or more crude oil or natural gas wells and is pressurized to at least five (5) pounds per square inch gauge pressure and allows liquids to continuously flow through the unit at steady state conditions. The pressurized primary separator must be located upstream of any vessel or location where flashing may occur.

- Liquids may not "continuously flow" through the separator. Some separators periodically dump liquids to the next stage of separation.

- If there are multiple stages of separation between the well and the storage tank where flash gas can vent to atmosphere, then a primary pressurized separator may not be both "the first vessel that receives crude oil, condensate, or produced water from one or more crude oil or natural gas wells" and "located upstream of any vessel or location where flashing may occur."
  The liquid sample should be collected from the separator immediately upstream of the storage tank or other vessel from which flash gas will vent to atmosphere. Samples should be collected when the separator is operating at a typical/normal pressure and temperature such that resulting flash gas is representative of annual average conditions (i.e., these GOR and GWR values will be used to estimate annual emissions).

Section 12.1 (Flash Liberation Test Equipment Requirements) and Section 12.2 (Flash Liberation Test Requirements)

- Is there a standard test method for measuring the volume of flash gas **(i.e., flash gas volume liberated during lab analysis)**? **[§12.1(b)]**
- The GOR or GWR are impacted by the ~~flash~~ **final** temperature. Higher temperatures result in larger GOR and GWR, and lower temperatures result in smaller GOR and GWR. Because these GOR and GWR values will be used to estimate annual emissions, it is recommended that the flash test be conducted at the annual average tank or ambient temperature (e.g., post-flash liquid temperature **in the tank**). **[§12.2(a)-(d)]**
- If the sample liquid contains both oil and water, how will GOR and GWR be calculated? **[§12.2(f)]**

Additional General Comments:

CARB Environmental Analysis to justify proposed standards and applicability thresholds

A rule development process should include timely environmental and cost benefit analysis to justify regulatory requirements. CARB plans to release its analysis with the formal rule proposal this summer, and it appears that regulatory options in the draft proposal have not been adequately justified. The draft regulatory language in the April 22, 2015 document generally bases requirements on existing regulations, such as the VOC NSPS for oil and natural gas operation (40 CFR, Part 60, Subpart OOOO) and state or local leak detection and repair (LDAR) programs. The draft proposal for existing sources often includes more rigorous applicability thresholds and emission standards then VOC-based criteria for new sources from Subpart OOOO. Those requirements may not be appropriate – especially when considering methane emission reductions rather than a VOC regulation. Because the Environmental Analysis is not yet available, detailed comments are not provided at this time. However, SoCalGas expects that some of the proposed requirements will not withstand a cost benefit analysis that considers reasonable cost effectiveness thresholds for a methane regulation. SoCalGas anticipates providing specific comments when CARB releases its analysis and support documentation. However, additional general discussion is provided in these comments.

CARB includes sources analogous to those in Subpart OOOO. EPA chose not to include the transmission and storage (T&S) sectors in the Subpart OOOO final rule, because VOC reductions were trivial from T&S sources and regulation was not justifiable. However, the EPA proposed rule included T&S VOC sources. The CARB draft regulatory proposal includes T&S sources analogous to those in the Subpart OOOO proposed rule: reciprocating compressor rod packing, centrifugal compressors wet seal degassing vents, equipment leaks, and pneumatic devices. However, in many cases the draft proposal criteria for an *existing* source rule are more rigorous than NSPS requirements for *new* sources. In some cases, CARB relies on VOC analogies (e.g., concentration thresholds for leaks) from local rules that may not be justifiable for a methane regulation, because cost effectiveness thresholds for GHGs should differ from VOC-based thresholds. Additional discussion follows. All applicability thresholds (e.g., leak thresholds) and emission standards should be thoughtfully reviewed in a detailed Environmental Analysis that assesses whether the draft proposed requirements are justified.

- <u>GHG thresholds should differ from regulatory parallels based on VOCs or other criteria or air toxic pollutants</u>. It is commonly understood that regulatory mass-based emission thresholds for GHGs should differ from other pollutants. EPA attempted to address this through its tailoring rule, which would have established significantly higher permitting thresholds for GHGs than other pollutants. Although that rule did not withstand legal review, the underlying premise remains intact and will be implemented by EPA – e.g., emission thresholds on the order of 75,000 to 100,000 tons per year (TPY) CO_2 equivalent emissions for GHGs will apply for permitting actions such as BACT review rather than the emissions thresholds *three orders of magnitude lower* for criteria pollutants such as NOx. Similarly, although GHG costs effectiveness criteria are not well established, cost effectiveness criteria vary by several orders of magnitude compared to conventional pollutants. For example, BACT cost effectiveness thresholds for NOx or VOCs are on the order of thousands to tens of thousands of dollars per ton (e.g., $5,000 per ton). Analogous cost thresholds for GHG reductions generally consider either the economic value of reductions in an emission trading scheme or the "social cost of carbon" from a recent EPA report. These costs are on the order of $10 to $50 per ton. The CARB regulatory proposal should consider the amount of reductions and cost benefit of reductions in its Environmental Analysis, and should establish appropriate thresholds for methane reductions, and not rely on criteria established for conventional pollutants. Methane emission thresholds should be orders of magnitude different than similar regulations for VOC reductions. SoCalGas expects that a reasonable environmental analysis would conclude that appropriate applicability thresholds have not been established in the draft proposal.

- <u>VOC-based leak thresholds are not appropriate for methane equipment leak standards</u>. LDAR regulations across the U.S. include a range of "leak thresholds," which use concentration measurements to define a leak, and assume that concentration serves as a proxy for the leak rate. As discussed below, concentration does not provide an accurate indicate of leak rate. Rigorous leak thresholds are included in some jurisdictions due to the need to achieve VOC reductions in response to ozone nonattainment. For example, the most common LDAR concentration threshold for VOC programs is 10,000 ppmv. Thresholds on the order of 1,000 or 500 ppmv apply in some areas where available ozone precursor reductions are limited and stringent VOC criteria apply. Since GHG emissions are an international concern rather than a local air quality issue, it should not be presumed that rigorous VOC-based leak thresholds are appropriate for a methane equipment leak program.

  A rigorous analysis should be completed to properly assess methane reductions and associated costs. That analysis should not include the faulty assumption espoused by some parties that nearly all leaks can be quickly and inexpensively repaired. SoCalGas expects that a thoughtful analysis will conclude that higher concentration thresholds should apply for a methane program, or that an approach such as directed inspection and maintenance (DI&M) should be included as an alternative. DI&M was discussed in comments provided to CARB in January.

  In addition, an overly stringent leak threshold is inconsistent with EPA documents and recent publications that indicate a small percentage of leaks are responsible for the vast majority of methane emissions from T&S operations.

- <u>EPA documentation and recent results indicate that few sources are responsible for the majority of methane emissions from leaks</u>. SoCalGas provided comments in January 2015 that discussed DI&M for methane leaks as a cost effective alternative to conventional LDAR. Those comments referred to EPA documentation from the Natural Gas STAR program, and CARB should revisit the previous comments and citations. Recent publications from studies being conducted by EDF in collaboration with industry participants reinforce the conclusion that finding that repairing "large leakers" can provide significant reductions.[3] Additional

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[3] *Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol*, Subramanian, et. el., Environmental Science and Technology, Volume 49, Issue 5 (web publication February 10, 2015).

consideration is needed in a rigorous Environmental Analysis document to establish reasonable criteria (e.g., leak concentration or leak rate threshold) and alternatives (e.g., DI&M) for reducing methane emissions from equipment leaks.

- Leak-based thresholds should not be used as a basis for reciprocating compressor rod packing maintenance decisions. The draft proposal includes a leak threshold for rod packing emissions from engines 500 horsepower (hp) and smaller. Some emissions are anticipated from rod packing as part of normal operation. Due to this fact and the fact that methane concentration in natural gas is generally higher than VOC content in process streams with VOC LDAR, a standard (i.e., maintenance) based on a 1,000 ppmv threshold is more rigorous than an analogous VOC LDAR program. As discussed in a comment below, based on data from a CSUF study, the associated methane emissions are immaterial. Analysis is needed to demonstrate the environmental benefit and associated costs of the proposed rod packing standard for compressors 500 hp and smaller. It is very likely that the proposed criterion is not justifiable. The draft proposal should be revised to include an emission rate based threshold for smaller engines similar to the threshold proposed for engines >500 hp.

It is recommended that support documentation planned for release this summer be completed and released as soon as practical. That analysis should be thorough and consider appropriate regulatory criteria for a methane emissions program that differ from the criteria used for historical VOC-based regulations. Once additional details on cost benefit and cost effectiveness analyses are available, more substantive comment on those criteria and associated regulatory thresholds can be provided.

Timing and implementation period – environmental benefit

Timing for repairs is impractical and generally not consistent with environmental benefit. Longer timeframes for repair are warranted. The draft proposal includes schedules for repair that are unnecessarily short and not justified. As discussed above, analysis should be completed to assess the environmental benefit and consequences associated with proposed schedules. A more reasonable and justifiable approach should be presented in the upcoming rule proposal.

For example, rod packing maintenance is required for reciprocating compressors 500 hp and smaller within 2, 3, or 7 days depending on the leak concentration measured. As discussed above, leak threshold criteria are not appropriate for rod packing maintenance and action will be unnecessarily triggered. The response times will also add unnecessary burden that does not derive meaningful benefit. Examples of emissions potential can be assessed based on leak data shown in Table 2 from CSUF measurements.

For example, Table 2 shows an average leak rate of 44 *pounds* CO_2e methane emissions per day for a concentration between 1,000 and 10,000 ppmv. At 10,000 ppmv to 50,000 ppmv, the average leak rate is 110 pounds a day. The draft proposal requires repair within 7 days for the former case, and within 3 days for the latter. Based on the allowed time for repair and assuming the average leak rate from Table 2, this equates to just over 300 pounds for each of these two cases. If it is assumed that two weeks are allowed for repair, methane emissions are 1,540 pounds (0.8 tons) CO_2e for the larger leak and 0.3 tons for the smaller leak. As discussed above, significantly higher emissions thresholds are warranted for GHGs than for criteria air pollutants or air toxics. One ton of GHG emissions is immaterial. For example, the 0.8 tons of emissions from the larger source over a two week period are equal to 0.7 metric tons CO_2e. This equate to less than 0.003% of the amount necessary to trigger reporting under the federal GHG reporting program threshold of 25,000 metric tons per year.

It appears that the schedule for repairs are based on stringent schedules associated with VOC programs in areas with longstanding air quality challenges. This should not be the basis for a methane emissions program. If two weeks is allowed for repair rather than the prescribed times in the draft proposal, "additional" emissions would be well under a ton of CO_2e emissions. Rigor should not be prescribed without justification, and more reasonable repair schedules are appropriate.

In addition, any schedule based on elapsed "days" should clearly indicate *business* days. Additional flexibility should also be offered to allow a decrease in the frequency of inspections or surveys over time as leak mitigation programs demonstrate that reasonable performance objectives are being met and maintained.