Appendix B:

Economic Analysis

ECONOMIC ANALYSIS

A. Summary of Proposed Costs and Impacts

The proposed Regulation for the Reduction of Greenhouse Gas Emission Standards from Crude Oil and Natural Gas Facilities (proposed regulation) is intended to reduce GHG emissions from oil and gas production, processing, storage and transmission compressor stations. The economic impacts of the proposed regulation are discussed in this section, and include impacts and benefits to businesses, individuals, and government agencies. This section also includes a discussion of the estimated cost of the proposed regulation and an analysis of alternatives.

The proposed regulation increases costs on the complying industries, which are primarily involved with oil and gas extraction, and natural gas storage and transmission. These industries, referred to as primary industries, pay for control equipment and services from secondary industries but may also achieve operational cost savings through recovery of natural gas captured by the proposed control strategies. ARB estimates the proposed regulation will cost about $23 million dollars per year, or about $14 million per year without the Monitoring Plan, and is expected to reduce GHG emissions by about 1.5 Million MT CO_2e per year on a 20 year horizon. However, considering the size and diversity of the California economy, the economic impacts of the proposed regulation on the California economy are negligible, including the impact on growth of employment, investment, personal income, and production.

B. Major Regulations

For a major regulation proposed on or after January 1, 2014, a Standardized Regulatory Impact Assessment (SRIA) is required. A major regulation is one "that will have an economic impact on California business enterprises and individuals in an amount exceeding fifty million dollars ($50,000,000), as estimated by the agency." (Govt. Code Section 11342.548) Further, the Health and Safety Code Section 57005(b) defines a "major regulation" as any regulation that will have an economic impact on the state's business enterprises in an amount exceeding ten million dollars ($10,000,000), as estimated by the board, department, or office within the agency proposing to adopt the regulation in the assessment required by subdivision (a) of Section 11346.3 of the Govt. Code.

When amortized, the proposed regulation will cost $23 million per year; however, the largest expenditures will be in 2018 when most of the capital equipment is expected to be purchased. This upfront cost is estimated to be over $40 million in direct costs in 2018, resulting in an overall economic impact of over $50 million. Due to the estimated economic impact of compliance exceeding $50 million in a 12 month period during 2018, the proposed regulation was determined to be a major regulation and required a SRIA. A SRIA was submitted to the Department of Finance (DOF) in April 2015. On May 28, 2015, ARB received a letter from the DOF acknowledging the status of a major regulation, and commenting on the information presented in the SRIA. These comments are addressed at the end of this Appendix.

Since the submittal of the SRIA, the proposed regulation has undergone several changes. In addition to changes in the standards, there have been changes to the methodology of estimating the cost and emissions for provisions of the proposed regulation due to the availability of updated data and feedback from industry representatives and other stakeholders. Although these changes have been made after the submittal of the SRIA, staff believes the conclusions of the SRIA continue to be accurate, since the overall annual cost, emissions, reductions, and impacted industries are similar.

In addition to changes made to the standards of the proposed regulation, ARB is now using the 20 year AR4 value (72) of GWP for methane instead of the 100 year AR4 value (25) to determine the reductions in CO2e. The use of GWPs with a time horizon of 20 years better captures the importance of the short lived climate pollutant (SLCP) and gives a better perspective on the speed at which SLCP emission controls will impact the atmosphere relative to CO2 emission controls. Also, the value assigned to natural gas saved changed from \$4.10 per mscf to \$3.44 per mscf. This value was changed to reflect the most recently available data and is the average wholesale price that is specific to California over the last 12 months of available data, from November 2014 to October 2015 (EIA, 2016). Also, the compliance dates for the regulation have changed from starting January 1, 2017, to starting January 1, 2018.

In addition to the changes discussed above, some of the methodologies of estimating the potential costs and emissions have changed. This is due to the availability of better data, stakeholder comments, as well as the continued development of the proposed regulation. These changes are described in detail below. All SRIA emissions use a GWP of 25, and all current emissions use a GWP of 72 in the descriptions.

1. Changes from SRIA by Category

a) Reciprocating Compressors

In the SRIA version of the proposed regulation, all reciprocating compressors would need to replace a rod packing after three years of use. In the current version of the proposed regulation, compressors at production facilities are no longer subject to a rod packing leak standard, but instead are required to meet an LDAR standard. Many of the compressors at production facilities are smaller, may be portable, and handle a different composition of gas than compressors at processing, storage or transmission facilities. Also, most of the available data concerning leak rates and rod packing cost and performance are from larger compressors that are typically not found at production facilities. The provision to exclude production type compressors eliminated over 600 of almost 1000 compressors from this segment, for determining cost and emissions. In addition, industry provided data on the leak rate by compressor for a large subset of the remaining compressors. This new data was used in place of the emission factors previously used. With the reduction in number of compressors, the change from a time based standard to a performance based standard, and using measurement data instead of emission factors, the estimated reduction of emissions has changed from 143,000 MT CO2e to about 68,000 MT CO2e. Based on the decrease of compressors potentially impacted by the standard for rod packing leaks, the estimated cost of compliance has decreased from about $600,000 per year to about $260,000 per year.

b) Centrifugal Compressors

In the SRIA version of the proposed regulation, twenty five centrifugal compressors with wet seals were anticipated to need a vapor recovery system or to be converted to a dry seal. In an effort to verify this data from ARB's 2009 Oil and Gas Industry Survey (ARB, 2013), staff contacted the facilities that would be impacted by this provision in the proposed regulation. All centrifugal compressors, except for one, were reported with wet seals in error, are no longer in use, have been replaced with a compressor with a dry seal, or now have a vapor recovery system installed to control emissions. In addition, measurement data taken directly from this single compressor was used in place of the emission factors used to generate the emissions and reductions for the SRIA. Due to the updated number of impacted units, the emissions dropped from about 20,000 MT CO2e to about 3,700 MT CO2e and the reduction estimates dropped from about 11,000 MT CO2e to about 3,500 MT CO2e. The associated cost of compliance decreased from about $375,000 per year to about $6,000 per year.

a) Leak Detection and Repair (LDAR)

In the SRIA version of the proposed regulation, the emissions did not include a small percentage of super emitter components, which are responsible for the majority of emissions. In addition, the LDAR program was changed from an annual inspection to a quarterly inspection requirement. These changes were made to address stakeholder comments, and ensure emissions were determined with the best available data. The estimated emissions reduction has changed from about 1,200 MT CO2e to about 590,000 MT CO2e, and the estimated cost has changed from about $2 million per year to about $10 million per year.

b) Pneumatic Devices

At the time of the SRIA, all continuous bleed pneumatic devices were required to change to a low bleed pneumatic device. Based on stakeholder feedback, this has been changed to require a no bleed pneumatic device in the current proposed regulation to maximize emission reductions with no increased cost. Also, after a review of the data, the count of continuous bleed devices was overestimated by about 170. The anticipated emissions reduction from this segment have changed from about 124,000 MT CO2e to about 320,000 MT CO2e, and the estimated cost has changed from about $1.3 million per year to about $1.2 million per year.

c) Tank and Separator Systems

The provisions for tank and separator systems have changed from requiring a vapor recovery system for all uncontrolled systems, to require vapor recovery and comply with a NOx emission standard, but only for uncontrolled systems that are anticipated to have over 10 MT per year of CH4 emissions. Due to this change, the estimated number of systems impacted changed from over 600 to about 300. It is now assumed that a low NOx incinerator will be used to comply with the NOx emission standard in place of a flare. The emissions are now calculated with the throughput to the separators instead of reported emissions from the 2009 Survey. The estimated emissions reductions have changed from about 252,000 MT CO2e to about 540,000 MT CO2e. The estimated cost has changed from about $16 million per year to about $4.7 million per year.

d) Well Stimulations

The current proposal uses emission factors from WSPA (WSPA, 2015) to estimate emissions from well stimulations. These emission factors became available after the submittal of the SRIA when the best available data projected much greater emissions. The estimated emissions reduction from this segment of the proposed regulation has changed from about 24,400 MT CO2e to about 5,000 MT CO2e. The estimated cost has changed from about $200,000 per year to about $460,000 per year due better cost data becoming available and inclusion of additional compliance equipment in the current Proposed Regulation.

e) Liquids Unloading

The requirement for controls for liquids unloading were removed for the proposed regulation, and replaced with a reporting requirement. The estimated reductions of about 350 MT CO2e have been eliminated, and the expected cost of $450,000 per year has been replaced with a cost of about $6,000 for recordkeeping, reporting and other administrative tasks.

f) Monitoring Plan

The proposed regulation now includes a requirement for operators of natural gas underground storage facilities to follow a Monitoring Plan, which includes daily monitoring of natural gas storage wells, and continuous ambient air monitoring. This was not included in the SRIA version of the proposed regulation. The cost for the Monitoring Plan is estimated to be about $8.7 million per year.

C. Summary and Interpretation of the Results of the Economic Impact Assessment

The proposed regulation encourages the use of more efficient and potentially cost-saving technology to ensure maximum production of natural gas. Much of the capital equipment purchased, such as vapor recovery for tanks, have lifetimes that far exceed the pay-off period. Though at some point the primary industries no longer are making payments for the capital required for compliance, they continue to enjoy the natural gas savings that are provided by that capital. Therefore the primary industries, oil and gas extraction and natural gas distribution, are required to make minor changes to their production facilities, these modifications include increases in efficiency. Secondary industries face increased product demand, resulting in increased output and employment in those industries.

The proposed regulation was analyzed using generally high estimates and GHG emission reduction estimates, thus the analysis may serve as an upper bound of anticipated impacts. To the extent there are greater cost savings due to increased product capture, the economic impacts of the proposed regulation would be less negative in all years, and likely show a benefit to the economy. This result would persist in later years and the primary industries, having made a large initial investment in the capital necessary to prevent substantive leaks, would continue to see savings long after the payments for the capital are finished.

The proposed regulation is unlikely to significantly impact California’s economy, including the growth of employment, investment, personal income, output, and GSP does not represent a significant change from Business as Usual (BAU).

D. Benefits

The proposed regulation is anticipated to deliver environmental benefits that include an estimated annual reduction in GHG emissions, beginning in 2018, of about 1.5 million MT CO_2e per year from oil and gas related operations in California. In addition, the proposed regulation is expected to save primary industries about 800 million standard cubic foot (scf) per year of industrial natural gas through reductions of leaks and vapor recovery systems[1]. This will result in a savings of about $3 million per year, assuming the value of this gas is $3.44 per Mscf. The cost per ton of the proposed regulation is estimated to be approximately $15 per MT CO_2e reduced. These estimates use the 20-year GWP for methane (i.e., 72) from the Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Report (AR4).

Reducing SLCPs, such as methane, can produce near term results that deliver immediate and tangible climate, air quality, economic, and health benefits while longer-term changes are being implemented.

The proposed regulation is expected to provide co-benefits of reductions in emissions of VOCs and toxic air contaminants that are emitted from uncontrolled oil and water storage tanks and released from well stimulation circulation tanks. The estimated reduction in VOCs is approximately 3,630 tons per year, or about 10 tons per day statewide. There was the potential for NO_x increases for vapor recovery units if the facility used a flare. Since ARB is requiring a NOx standard in these cases, the tank measure provides a benefit of 1.6 tonnes per year but there are NOx impacts from LDAR, leading to an overall impact that is neutral for the state as a whole. Table B-1 summarizes reductions of all pollutants, and detailed calculations are in Appendix D.

[1] This assumes gas is 94.9% CH4.

Table B-1. Summary of Non-GHG Pollutant Reductions

Category	Total Hydrocarbons	VOCs	Benzene	Toluene	Ethyl-Benzene	Xylenes	NOx
Vapor collection on uncontrolled oil and water separators, tanks, and sumps with emissions above a set methane standard[1]	10,458	1,362	23	11	1.7	8.5	1.6
Control of vapors from uncontrolled well stimulation circulation tanks	96	12	0.2	0.1	<0.1	<0.1	<0.1
Leak Detection and Repair (LDAR) on components, such as valves, flanges, and connectors currently not covered by local air district rules	9,698	1,264	22	10	1.5	7.9	(1.6)[2]
Inspection and repair requirements for reciprocating natural gas compressors	1,318	172	3.0	1.4	0.21	1.1	NA
Vapor collection of centrifugal compressor wet seal vent gas, or replacement of higher emitting “wet seals” with lower emitting “dry seals”	68	9	0.2	<0.1	<0.1	<0.1	NA
Replacement of pneumatic pumps, and replacement or retrofitting of pneumatic devices under certain circumstances	6,199	808	14	6.5	1.0	5.0	NA
TOTAL (benefits from proposed regulation)	27,837	3,627	62	29	4.6	23	(<0.1)

[1] All estimated emission reductions from this category are occurring in the San Joaquin Valley Air Basin.
[2] ARB estimates that increased LDAR will result in increased NOx from vehicle emissions by 1.6 tons/year.

1. Benefits to Individuals

The proposed regulation will not directly affect individual consumers; however, as a result of the anticipated decrease in methane emissions, VOCs, and other toxic air contaminants, the proposed regulation will provide health and climate benefits.

Like emissions of other GHGs, emissions of methane due to human activities (anthropogenic emissions) have increased markedly since pre-industrial times. Of the GHGs emitted as a result of human activities, methane is the second most important GHG after carbon dioxide (CO2), accounting for 14 percent of global GHG emissions in 2005. Though methane is emitted into the atmosphere in smaller quantities than CO2, its global warming potential (i.e., the ability of the gas to trap heat in the atmosphere) is 72 times that of CO2, resulting in methane's stronger influence on warming during its atmospheric life time.[2]

Emissions reductions of GHGs, VOCs and other pollutants have been correlated with a reduction in the risk of premature deaths, hospital visits, and a variety of other health impacts, especially in sensitive receptors including children, elderly, and people with chronic heart or lung disease. Methane is a contributor to ground level ozone, and cutting methane emissions reduces smog, which is associated with higher rates of asthma attacks. Ozone affects respiratory health, crop productivity, and ecosystems, and recent studies have shown substantial evidence that ozone influences premature mortality.[3][4]

2. Benefits to California Businesses

The proposed regulation requires the oil and gas industry to purchase, retrofit, and service capital equipment. The requirements of the regulation would increase the demand for these services and increase business opportunities for secondary industries both within and outside of California. Additionally, the proposed regulation is designed to reduce industrial natural gas leakage, which will result in cost savings for the regulated parties. For example, many of the proposed control strategies are designed such that natural gas can be recovered and either used on site as energy or captured for sale. These savings are estimated to be about $3 million per year. While the primary industries are not small businesses, some of the secondary industries contain small businesses. If these businesses were able to meet

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2 GMI. 2016. About Methane. https://www.globalmethane.org/about/methane.aspx

3 Whitehouse. 2016. Climate Action Plan Strategy to Reduce Methane Emissions. https://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf

4 West, Jason J., Arlene M. Fiore, Larry W. Horowitz, and Denise L. Mauzerall. 2016. Ozone Air Quality Management by Reducing Methane Emissions: Global Health Benefits (HTAP, 2016). http://www.htap.org/meetings/2006/2006_01/posters/West_methane.pdf

the increased demand and provide the capital equipment and services to the primary industries for compliance, small businesses would see increased demand, output and, likely, employment.

ARB estimates that more than $25 million each year will be spent on control equipment and inspection services. This includes over $10 million to comply with the LDAR provisions in the proposed regulation, and over $8 million to comply with the Monitoring Plan. Companies involved in LDAR inspections may see an increase in business or expansion. In areas of the state that previously did not have an inspection program, there will be new demand for a previously unneeded service, which may result in new businesses being created.

In areas without existing VOC based regulations for LDAR or higher pressure natural gas systems, LDAR is likely to be more cost effective. In addition, we believe that with the advent of newer technologies, the efficiency of LDAR inspections will improve.

While direct costs to the primary industries exceed $40 million in the first year of implementation, these industries achieve savings of about $3 million annually from leakage prevention strategies within the proposed regulation. Secondary industries also achieve benefits, as demand for their equipment, services, or other products such as natural gas increases yielding positive economic benefits.

3. Costs per Ton

Table B-2. Summary of Cost, Emissions, and Cost per Ton

Provision	Annual Cost	Annual Savings	Reductions (MT CO2e)	Cost per Ton ($ / MT CO2e reduced)	Cost per Ton with Savings ($ / MT CO2e reduced)
VRU for Tanks	$4,700,000	$500,000	540,000	$ 9.00	$ 8.00
Reciprocating Compressors	$260,000	$180,000	68,000	$ 4.00	$ 1.00
LDAR	$10,000,000	$1,500,000	590,000	$ 17.00	$ 14.00
Pneumatic Devices	$1,200,000	$840,000	319,000	$ 4.00	$ 1.00
Well Stimulations	$460,000	$0	5,000	$ 91.00	$ 91.00
Centrifugal Compressors	$6,000	$9,000	3,500	$ 2.00	$ (1.00)
Monitoring Plan	$8,700,000	$0	0	-	-
Total	**$25,400,000**	**$3,000,000**	**1,500,000**	**$17.00**	**$15.00**

All Figures are in 2015 dollars

E. Direct Costs

1. Direct Costs on Individuals

For 2017, the baseline projected outputs for oil and gas extraction and natural gas distribution industries are approximately $25 billion and $19 billion respectively. The ratio of compliance cost to total output is less than 0.5 percent for both industries, making pass-through of costs unnoticeable. However, to the extent that any potential costs are passed on to individual consumers, minor increases in the price of natural gas and electricity may occur.

2. Direct Costs on Typical Businesses

Any business involved with crude oil or natural gas extraction, natural gas storage, crude oil processing excluding refineries, natural gas processing (including gas plants), crude oil tank farms (excluding tank farms at refineries), or transmission of natural gas will potentially be impacted by the proposed regulation. In February 2009, ARB conducted an Oil and Gas Industry Survey for crude oil and natural gas production, processing, and storage facilities in California (ARB, 2013). The survey was completed by 325 companies representing over 1,600 facilities and approximately 97 percent of the 2007 crude oil and natural gas production in California. Out of these companies, 272 companies that responded to the survey are expected to be impacted by the provisions in our proposed regulation.

ARB estimates the direct cost to industry for the proposed regulation to be approximately $25.4 million per year. This includes the amortized cost of capital equipment, and annual costs for labor, maintenance, reporting and recordkeeping. ARB generally used high estimates throughout for estimating emissions, costs, and reductions. The average impact each of the 272 businesses is expected to be about $100,000 per year. The typical businesses are not small because the primary industries are ineligible to be classified as small under government code.[5] Therefore, the increased costs on industry do not directly impact small businesses.

3. Cost Analysis

This section describes the sources and methodology to determine the emissions, cost, and cost per ton of our proposed regulation. In general, for each segment of the regulation, staff identified the number of devices affected, estimated the cost to comply with the regulatory provisions, estimated emissions and reductions, and accounted for any savings to be included in the cost per ton. The methodology to determine these items for each segment of the regulation is described below.

The indirect costs and economic impacts were modeled using a computational general equilibrium model of the California economy known as Regional Economic Models, Inc. (REMI). The REMI model generates year-by-year estimates of the total regional effects of a policy or set of policies. These results and analysis are included with the SRIA in Attachment E. The results helped evaluate the impact of the proposed regulation on California's economy, including business impacts, job creating, and impacts to

[5] California Government Code Section 11342.610(b). 2016. http://www.leginfo.ca.gov/cgi-bin/displaycode?section=gov&group=11001-12000&file=11342.510-11342.610

individuals. Finally, alternatives to the proposed regulation were evaluated and fiscal impacts to ARB and local air districts were estimated.

The cost estimate of the proposed regulation follows guidelines recommended by the California Environmental Protection Agency (Cal/EPA), and is consistent with the methodologies used in previous cost analyses for ARB regulations (ARB, 1999; ARB, 2000; ARB, 2004; ARB, 2005; ARB, 2007). The segments analyzed for this proposed regulation include control strategies for reciprocating compressors, centrifugal compressors, oil and water separators and storage tanks, pneumatic devices, circulation tanks for well stimulations, and a leak detection and repair (LDAR) program. Information from the 2009 Survey, of which parts were later updated by staff to account for changes since 2009, was used to form the basis of the number and types of facilities potentially impacted, number and types of equipment, and estimated emissions reduction from the standards in the proposed regulation. After the number and types of equipment impacted were identified, the direct cost to industry was estimated for each component of the regulation. Sources of data include ARB's 2009 Survey, ICF's Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF Report), EPA documents including their Gas Star Program, industry groups, and communications with operators of potential control equipment, and other stakeholders.

4. Methodology

One-time costs, such as the cost for purchasing capital equipment, are amortized to reflect that businesses generally do not pay the total cost up front, and allows for annual cost to be compared to an annual emission reduction. The Capital Recovery Method for amortizing fixed costs is recommended by Cal/EPA guidelines (Cal/EPA, 1996). This method of amortizing a fixed cost was used for all capital costs of equipment, installation, and costs of testing.

The CRF is calculated as follows:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

where,

CRF = *Capital Recovery Factor*

I = *discount interest rate (assumed to be 5%)*

n = *project horizon or useful life of equipment*

With regard to the discount rate, Cal/EPA recommends 2 percent plus the current yield for a U.S. Treasury Note of similar maturity to the project horizon and adjusted for inflation (Cal/EPA, 1996). The primary rationale for using a real discount rate of five percent is that it is equivalent to rate of return on an inflation-adjusted 10-year treasury security, (about 2 percent in the past five years) , plus the California Environmental Protection Agency recommended 3 percent risk premium. The five percent real discount rate has been used for several recent ARB regulations, and follows guidelines for economic analysis in the AB 32 Scoping Plan (ARB, 2010b). Additionally, the five percent is the average of what the US Office of Management and Budget recommends (7 percent) and what US Environmental Protection Agency has used historically for regulatory analysis.

The project horizon was chosen to reflect the expected equipment lifetime, and is based on the amortization period used by ICF when applicable (ICF, 2015). In cases when cost estimates were outside of the scope of the ICF report, the equipment lifetime is based on communications with equipment manufacturers. These values and the calculated capital recovery factors are summarized in Table B-3.

Table B-3. Equipment Lifetime and Capital recovery Factor for Control Equipment

Equipment	Amortization Period	Capital recovery Factor
Rod Packing for Reciprocating Compressors	3	0.367
Vapor Recovery for Centrifugal Compressors	10	0.130
No Bleed Pneumatic Devices	7	0.173
Vapor Recovery Equipment for Tanks and Well Stimulations	10	0.130
Gas Separator for Well Stimulation	10	0.130
Monitoring Plan Equipment	10	9.130
Flash Test[6]	3.3	0.333

[6] Flash tests are required on uncontrolled tank and separator systems, and controlled systems with uncontrolled water tanks every year for the first three years, and once every five years thereafter. Over 20 years, tests are conducted on average every 3.3 years.

This capital recovery factor was multiplied by all non-recurring costs, including capital costs for equipment and installation, and testing costs. This value was added to the total ongoing costs, such as labor, maintenance, recordkeeping, and fuel costs to determine the total cost per year.

$$Total\ Cost\ per\ Year = Annualized\ Nonrecurring\ Costs + Annual\ ongoing\ Costs$$

Where,

$$Annualized\ Nonrecurring\ Costs = CRF\ x \sum (Nonrecurring\ Costs)$$

$$Annual\ Ongoing\ Costs = Labor\ Costs + Maintenance\ Costs + Fuel\ Costs$$

The emissions were calculated from a combination of emission factors, survey data, and other data provided by stakeholders. There are two primary methods used to determine emissions based on the available data. The first method to determine emissions involves converting a volume of gas into a mass of CO2e. This method was used for calculating emissions from reciprocating compressors and, centrifugal compressors. Combining this method with the appropriate conversion factors yields a mass of methane from cubic feet of gas. To perform these calculations, the following conversion factors and equations were used.

$$Mass\ of\ Methane\ (kg) = \frac{Volume\ of\ Methane\ (scf)\ X\ Molar\ Mass\ of\ Methane}{Conversion\ Factor}$$

$$Emission\ Reductions\ in\ MT\ CO2e = \frac{Mass\ of\ Methane\ (kg)\ X\ GWP}{1000}$$

where,

Conversion Factor = 836.2 scf/kg mol (API, 2009)

Molar Mass of Methane = 16.04 kg/k mol

kg = 1000 g

Metric Ton (MT) = 1000 kg

Global Warming Potential (GWP) of Methane = 72

Additional factors used include:

Mole Percentage of Methane in Gas from Production = 78.8% (API, 2009)

Cubic meter = 35.13 scf

The second method to determine emissions from a given segment was to use an emission factor. These emission factors expressed emissions in either the mass of methane emitted per equipment device per unit of time for the LDAR, tank and separator systems, and pneumatic devices segments (CAPCOA, 1999; API, 2004; API, 2009), or MT CO2e per event (WSPA, 2015) for well stimulations. Again combining this with the appropriate emission factors yields total mass of methane and CO2e.

$$Emissions = Emission\ Factor\ X\ Number\ of\ Devices\ X\ Usage\ per\ Year$$

The reciprocating compressors, centrifugal compressors, LDAR, pneumatic devices and portions of the vapor recovery for tank and separator systems segments of the proposed regulation would have a corresponding increase in product with the decrease of leaks or emissions. The value of the gas saved under these segments was counted as a cost savings as a result the standards imposed by the proposed regulation. Since only the reciprocating compressors, centrifugal compressors, and pneumatic pumps had emissions that were calculated directly from a volume of gas, it is convenient to back calculate a volume of gas from the mass of CO2e since this value is shared across all segments. In a similar fashion to how mass of CH4 was determined from a volume of gas, the volume of gas saved was determined from the mass of CH4.

$$Volume\ of\ Methane\ (scf)\ = \frac{MT\ CO2e\ X\ Conversion\ Factor}{Molar\ Mass\ of\ Methane\ X\ GWP\ X\ 1000}$$

Where,

Conversion Factor = 836.2 scf/kg mol (API, 2009)

Molar Mass of Methane = 16.04 kg/kg mol

Global Warming Potential (GWP) of Methane = 72

Metric Ton (MT) = 1000 kg

Savings were calculated using price data obtained from the U.S. Energy Information Administration (EIA). We chose to use the average wholesale price for the period of November 2014 to October 2015. This represents the cost of gas that a utility would pay to a producer. Since this gas has higher methane content than what is typical of gas in production, this volume was converted into an equivalent volume of gas with a composition of 94.9% CH4 gas (EPA, 2011; PG&E, 2016).

$$Volume\ of\ Gas\ (scf)\ =\ \frac{Volume\ of\ CH4\ (scf)}{.949}$$

The value of this volume of gas was determined by using the average wholesale price for California from November 2014 to October 2015 (EIA, 2016), or $3.44 per mscf.

The cost per ton is the ratio of total dollars to be spent to comply with the standard (as an annual cost) to the mass reduction of the pollutant to be achieved by complying with that standard. In this case, we calculated the cost per ton both with and without including savings.

$$Cost\ Per\ Ton\ =\ \frac{Total\ Cost\ per\ Year\ (\$)}{Total\ Emission\ Reductions\ per\ Year\ (MT\ CO2e)}$$

$$Cost\ Per\ Ton\ with\ Savings = \frac{Total\ Cost\ per\ Year\ (\$) - Savings\ per\ Year}{Total\ Emission\ Reductions\ per\ Year\ (MT\ CO2e)}$$

The cost, emissions, savings, and cost per ton for each segment are described in detail below.

5. Recordkeeping

To comply with the proposed regulation, several provisions have recordkeeping and reporting requirements. This includes 799 facilities that are required to keep records of inspection and repair for the LDAR provisions, flash tests for 1,065 tank and separator systems, 93 liquids unloading operations that are required to keep records, 255 facilities with well casings for heavy oil production, and leak records for 979 reciprocating compressors. The recordkeeping and reporting requirements impact 272 businesses. For each of the businesses impacted, an annual report to ARB was estimated to cost $144, or take 3 hours at $48 per hour. A Recordkeeping event, or keeping inspection and repair records for LDAR, a flash test, a liquids unloading calculation, or a recording of a leak rate for reciprocating compressors was assigned a cost of $48. These estimated costs of recordkeeping and reporting are in line with costs used with EPA's recordkeeping cost estimate for their proposed emission standards in the oil and natural gas sector (EPA, 2015). The total estimated cost for recordkeeping and reporting is about $330,000 per year.

F. Vapor Recovery for Separator and Tank Systems Provision

Under the proposed regulation, systems that are currently uncontrolled and emit greater than 10 metric tons per year of methane would be subject to vapor recovery requirements.

To determine the cost and emissions from tank and separator systems, we used the ICF report, industry information, ARB's 2009 Survey, and EPA's GasSTAR Document "Installing Vapor Recovery Units on Storage Tanks" (EPA, 2006b).

According to ARB's 2009 industry survey, there are 1150 uncontrolled tank and separator systems. Of these, 317 systems at 19 facilities had emissions greater than 10 TPY of methane. Twenty six of these systems had no vapor recovery systems, and 291 had only an uncontrolled water tank.

1. Cost of the Vapor Recovery for Tanks and Separators Provision

The separator and tank systems subject to vapor recovery will need to install systems and if the gas is being routed to an existing or new combustion device, that device must meet a NOx standard if the facility is located in a non-attainment area. Using data from ARB's survey, there are anticipated to be no new combustion devices and all impacted existing flares are expected to be in San Joaquin Valley non-attainment area.

Therefore, at each facility routing to a flare, it is anticipated that the current flare would need to be replaced by a low-NOx incinerator.[7] As a conservative assumption, we chose the smallest flare to be replaced. The incinerators we chose for our cost estimate range in price from $160,000 to $295,000, depending on size, and can operate with a capacity of up to 380,000 scf per day (Aeron, 2015a). We chose an appropriate size for each facility based on separator throughput from our survey data. It should also be noted that, through follow-up contacts, one facility was determined to be at three separate and unconnected locations, so each location would need its own incinerator and removal of a flare. Once the total throughput per day was determined, an appropriately sized incinerator was chosen from Table B-4 below. In some cases, a single facility reported to our survey was located in different physical locations. In these instances, each of the physical locations was treated as a separate facility for purposes of determining the correct size of incinerator, flare removal, and throughput.

$$\textit{Throughput per Day (scf)} = \textit{Volume from Newly Captured Emissions per Day} + \textit{Throughput of Smallest Flare per Day}$$

[7] A low NOx incinerator is one option for meeting the NOx standard. It is considered the most likely compliance route.

$$Volume\ of\ Newly\ Captured\ Emissions\ per\ Day\ (scf) = \frac{Total\ CH4\ Emissions\ (MT) X\ Conversion\ Factor\ X\ 1{,}000}{Molar\ Mass\ of\ CH4\ X\ CH4\ Composition\ X\ 365}$$

Where,

Conversion Factor = 836.2 kg/ k mol (API, 2009)

Molar Mass CH4 = 16.04 (API, 2009)

CH4 Composition = 78.8% (API, 2009)

$$Volume\ to\ Incinerator\ from\ Smallest\ Flare\ (scf/day) = \frac{Annual\ Throughput\ (\frac{scf}{year})}{365\,\frac{days}{year}}$$

Table B-5 summarized the data used to choose an appropriately sized incinerator for the facilities that need to replace an existing flare. The production of one of the facilities was spread across three different locations, and this was taken into account when determining throughput for the 11 systems that would need incinerators at 9 facilities.

Table B-4. Incinerators for Tank and Separator Systems

Uncontrolled Systems				
Total # of Systems	**Number of Systems w/o VRS**	**Flare Throughput of smallest flare on site (scf/yr)**	**Total CH4 Emissions (MT/yr)**	**Total Throughput (scf/day)**
22	19	1,825,000	413.06	79,869
1	1	2,107,083	18.81	9,183
2	2	375,945	30.44	6,547
Uncontrolled Water Tanks				
Total # of Systems	**# of Systems w/o VRS**	**Flare Throughput of smallest flare on site (SCF)**	**Total CH4 Emissions (MT/yr)**	**Total Throughput (scf/day)**
12	0	482,681	1372.92	250,169
14	0	5,660,000	1028.16	201,865
60	0	42,558,000	1788.00	440,679
3	0	48,298,000	76.65	146,216
1	0	6,780,000	10.40	20,460
3	0	31,023,000	46.68	93,455

Data from ARB's 2009 Survey

Table B-5. Incinerator Costs

Operating Capacity	Capital Cost	Installation Cost	Number Required
Up to 36,000 scf per day	$ 160,000	$ 80,000	6
Up to 270,000 scf per day	$ 235,000	$ 117,500	4
Up to 606,000 scf per day	$ 295,000	$ 147,500	1

Data from equipment manufacturer (Aereon, 2015a)

Once the number of incinerators was estimated, the cost was determined as follows:

$$Cost\ of\ Incinerator$$
$$=\ Number\ of\ Devices\ X\ Cost\ per\ Device\ X\ Capital\ Recovery\ Factor$$

$Where,$

Capital Recovery Factor = 0.130 From Table B-3

Therefore,

Cost of 36,000 scf per day Incinerators = 6 X ($160,000 + $80,000) X 0.130 = $186,480

Cost of 270,000 scf per day Incinerators = 4 X ($235,000 + $117,500) X 0.130 = $182,595

Cost of 606,000 scf per day Incinerator = 1 X ($295,000 + $147,500) X 0.130 = $57,304

Total Annual Cost of Incinerators = $186,480 + $182,595 + $57,304 = $426,379

In total, ARB estimates 11 flares would need to be removed and replaced with a low NOx incinerator. According to the ICF report, the cost of a flare was estimated to be about $50,000. We assumed the cost for removing this equipment would be 50% of the capital cost, which is in line with installation costs from EPA's GasSTAR estimates (EPA, 2006b). All costs were amortized over 10 years, which was taken from the period of amortization from the ICF report for vapor recovery units and represents the expected lifetime of equipment.

Cost of Flare Replacement = Number of Flares Replaced X Cost to Replace Flare X Capital Recovery Factor

Where,

Number of Flares Replaced = 11

Cost to Replace Flare = $25,000 (ICF, 2015; EPA, 2006b)

Capital Recovery Factor = 0.130 From Table B-3

Cost of Flare Replacement = 11 X $25,000 X 0.130 = $35,613

All 317 uncontrolled systems above the 10 metric tons per year threshold would need a vapor recovery system. In cases where only the water tank is uncontrolled, the new vapor recovery system for the water tank would route to the existing vapor recovery and control system. For each of these systems, an appropriately sized vapor recovery system was chosen based EPA's GasSTAR estimates (EPA, 2006b). The cost of these vapor recovery units ranged from about \$20,000 to \$26,000 in capital costs, and about \$15,000 to \$20,000 in installation costs.

Table B-6 shows the emissions and throughput from the facilities that would need to control emissions from water tanks. This data was used to choose an appropriately sized vapor recovery system.

$$Volume\ of\ Gas\ per\ Day\ (mscf\ /\ day) = \frac{Crude\ Water\ CH4\ Emissions\ (MT/yr)\ X\ Conversion\ Factor\ X\ 1{,}000\ kg\ /\ MT}{\text{Molar Mass of CH4 X 365 X Number of Systems X 1,000 }(\frac{\text{mscf}}{\text{scf}})}$$

Where,

Conversion Factor = 836.2 kg/ k mol

Molar Mass of CH4 = 16.04

Table B-6. Emissions and Throughput from Water Tank

Emissions Total # of Systems	Crude Water CH4 Emissions (MT/yr)	Volume Gas per day (mscf per day)
7	42	0.9
22	204	1.3
19	29	0.2
1	9	1.3
2	15	1.1
9	129	2.0
19	243	1.8
7	83	1.7
12	1,373	16.4
14	1,028	10.5
1	49	7.0
1	198	28.3
1	21	2.9
52	848	2.3
17	65	0.6
44	821	2.7
60	1,788	4.3
25	444	2.5
3	77	3.7
1	10	1.5
22	32	0.2
3	47	2.2
317		

Data from ARB's 2009 Survey

Once the throughput from water tank emissions was determined, a vapor recovery system was chosen from Table B-7. Most emissions from water tanks had throughput far below the smallest capacity vapor recovery system described in EPA's GasSTAR document “Installing Vapor Recovery on Storage Tanks" (EPA, 2006b).

Table B-7. Vapor Recovery Costs

Design Capacity	Capital Cost	Installation Cost	Ongoing Costs	Number Required
25 mscf / day	$ 20,421	$15,316	7,367	316
50 mscf / day	$ 26,327	$19,745	8,419	1

Data from EPA's “installing Vapor Recovery Units on Storage Tanks.” (EPA, 2006b)

The total cost of vapor recovery systems for the water tank emission were determined as follows:

$$Cost\ of\ Vapor\ Recovery = Number\ of\ Devices\ X\ (Cost\ per\ Device\ X\ Capital\ Recovery\ Factor + Ongoing\ Cost)$$

Where,

Capital Recovery Factor = 0.130 From Table B-3

Therefore,

Cost of 25 mscf per day Vapor Recovery = 316 X (($20,421 + $15,316) X 0.130 + $7,367)= $3,790,442

Cost of 50 mscf per day Vapor Recovery = 1 X (($26,327 + $19,745) X 0.130 + $8,419)= $14,408

Therefore,

Total Annual Cost of Vapor Recovery = $3,790,442 + $14,408 = $3,804,828

A flash test of both the oil and water portion is required of all uncontrolled tank and separator systems with greater than either 50 bbl per day oil throughput, or 200 bbl per day of water throughput. This test is required every year for the first three years, then once every 5 years thereafter. The estimated cost for this test is $560 each for the oil and water portion (OEC, 2016) including travel and sampling. About 1,100 facilities would need to perform this test. To account for variability in testing frequency, these costs are amortized over 3.3 years.

Testing Cost = ((Number of Oil Flash Tests + Number of Water Flash Tests) X $560) X Capital Recovery Factor

Testing Cost = ((1,065 + 1,073) X $560) X .33 = $395,102

2. **Recordkeeping, reporting, and testing costs are estimated as follows:**

Recordkeeping and Reporting Cost = Cost of Businesses Making an Annual Report + Cost of Recordkeeping for Tanks and Separators

Where,

Businesses Impacted by Tank and Separator Provision = 72

Cost of Annual Report = $144

Number of Flash Tests for Recordkeeping = 2,138

Cost of Recordkeeping = $48

Therefore,

Recordkeeping and Reporting Cost = ((72 X $144) + (2,138 X $48) X .33) = $37,287

The total cost of this provision is the sum of the previous parts of the cost estimate.

Total Annual Cost = Annual Cost for Incinerators + Annual Cost for Vapor Recovery + Amortized Cost for Flare Removal + Annual Cost for Recordkeeping and Reporting + Annual Cost for Testing

Total Annual Cost = $3,804,828 + $426,379 + $35,613 + $37,287 + $395,102 = $4,699,209

3. Emissions from the Vapor Recovery for Tanks and Separators Provision

To estimate emissions impacts from the implementation of the proposed regulation, staff used data from ARB's 2009 Survey. Staff used the number of separators in the Survey to determine the number of systems8 at each facility. Staff then used Western States Petroleum Association (WSPA, 2015) and California Air Resources Board crude and water tank flash data to determine emission factors in metric tons per barrel for methane, volatile organic compounds (VOC), and Benzene, Toluene, Ethylbenzene, and Xylene (BTEX). The emission factors were applied to the system throughputs of crude, water, and dry gas water, giving total methane, VOC, and BTEX emissions per system. The systems that will be subject to the Oil and Gas regulation are systems found to be uncontrolled with methane emissions exceeding 10 metric tons per year. A detailed description of these calculations is included in Appendix D.

[8] For purposes of this analysis, a system is defined as a separator and associated crude oil and water tanks.

Total emissions from uncontrolled tanks and separators is estimated to be 7,865 MT of CH4, or 566,005 MT CO2e using a GWP of 72. Reductions are expected to be 95%, or about 537,705 MT CO2e.

4. Savings from the Vapor Recovery for Tanks and Separators Provision

Savings are estimated to be about 2,637 MT CH4, based on the number of facilities that staff anticipates will either route the vapor collected through a collection system or will use it on site to operate a steam generator, or other equipment. Based on data from the 2009 survey, we considered emission reductions at facilities that had a collection system without an active flare, or the ability use the collected gas for an application on site, such as for a steam generator, to go towards savings. Savings are estimated to be $498,259.

$$Volume\ of\ Gas\ (scf) = \frac{Mass\ of\ CH4\ (MT)\ X\ Conversion\ Factor}{Molar\ Mass\ of\ CH4\ X\ .949\ X\ 1{,}000\ (\frac{mscf}{scf})}$$

Where,

Conversion Factor = 836.2 kg / k mol

Molar Mass of Methane = 16.04 (API, 2009)

Therefore,

$$\boxed{Volume\ of\ Gas\ (scf) = \frac{2{,}637\ MT\ CH4\ X\ 836.2\ \left(\frac{kg}{k}mol\right)\ X\ 1{,}000\ (\frac{mscf}{scf})}{16.04\ X\ .949} = 144{,}842{,}833\ scf}$$

Value of Gas Saved = Volume of Gas X Cost per mscf

Where,

Cost per mscf = $3.44 (EIA, 2015)

1 mscf = 1,000 scf

Therefore,

$$\boxed{Value\ of\ Gas\ Saved = \frac{144{,}842{,}833\ scf\ X\ \$3.44}{1000\ scf/mscf} = \$498{,}259}$$

5. Cost per ton of the Vapor Recovery for Tanks and Separators Provision

Cost per ton is estimated to be about \$8.73 per MT CO2e reduced, or about \$7.80 per MT CO2e reduced with savings.

$$Cost\ Per\ Ton\ = \frac{Total\ Cost\ per\ Year\ (\$)}{Total\ Emission\ Reductions\ per\ Year\ (MT\ CO2e)}$$

$$Cost\ Per\ Ton\ with\ Savings = \frac{Total\ Cost\ per\ Year\ (\$) - Savings\ per\ Year}{Total\ Emission\ Reductions\ per\ Year\ (MT\ CO2e)}$$

Where,

Total Cost per Year = \$4,699,209

Savings per Year = \$498,259

Total Emissions Reductions per Year = 537,705 MT CO2e

$$\boxed{Cost\ Per\ Ton\ = \frac{\$4{,}699{,}209}{537{,}705\ (MT\ CO2e)} = \$8.74 \text{ per MT CO2e}}$$

$$\boxed{Cost\ Per\ Ton\ with\ Savings = \frac{\$4{,}699{,}209 - \$498{,}259}{537{,}705\ MT\ CO2e} = \$7.81\ \ per\ MT\ CO2e}$$

G. Reciprocating Compressor Provision

The proposed regulation requires rod packings on reciprocating compressors to be replaced if the leak rate is above 2 scfm per cylinder. This applies to reciprocating compressors located at gathering and boosting compressor stations, natural gas processing plants, underground natural gas storage facilities, and transmission compressor stations.

According to ARB's 2009 Oil and Gas Industry Survey (ARB, 2013), there are 911 reciprocating compressors in the oil and gas sector in California. Also in 2009, ARB conducted a Natural Gas Transmission and Distribution Survey (ARB, 2015) which adds an additional 68 reciprocating compressors at transmission stations for a total of 979 compressors. The reciprocating compressors from the 2009 Survey include all upstream compressors. However, the proposed regulatory requirements vary by location with production compressors not subject to the 2 scfm per cylinder requirement. In order to separate the production compressors, staff used horsepower as a proxy for location and chose to exclude compressors that were reported to operate at an average load of less than 250 hp. Using this split, staff determined there were 325 compressors that would be subject to the 2 scfm per cylinder standard. This includes all 68 compressors from the transmission and distribution survey. The remaining compressors under 250 hp were assumed to be production field compressors, and are included in the LDAR program.

To estimate the portion of the 325 reciprocating compressors that may be over our proposed standard of 2 scfm per cylinder, staff relied on data provided by industry. . The data included measurements from rod packing vents for 55 reciprocating compressors taken over a four year period. According to the data, about 14% of the measurements indicated a leak rate of over 2 scfm per cylinder. Based on the data, staff estimated that 46 out of 325 non-production reciprocating compressors would have a leak rate of over 2 scfm each year, and would require a rod packing replacement to comply with the proposed regulation. Staff estimated that for each of these 46 compressors, two of the rod packings would need to be replaced to bring the leak rate into compliance. In total, 92 rod packings would need to be replaced each year to comply with the proposed regulation.

1. Costs of the Reciprocating Compressor Provision

According to ICF's "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries" (ICF, 2014), the cost of replacing a single rod packing on a reciprocating compressor is estimated to be $6,000. This includes installation. These costs are amortized over a period of three years, which reflects methodology used by ICF, and mirrors EPA's recommended period of replacement of 26,000 hours. The total cost of 92 rod packing replacements at $6,000 per replacement amortized over three years plus recordkeeping costs is about $260,000 per year for all businesses, as shown below.

$$Cost\ of\ Rod\ Packing\ Replacement$$
$$=\ Number\ of\ Devices\ X\ Cost\ per\ Device\ X\ Capital\ Recovery\ Factor$$

Where,

Number of Devices = 92 Rod Packing Replacements per Year

Cost per Device = $6,000 per Rod Packing Replacement (ICF, 2015)

Capital Recovery Factor = .367 from Table B-3

Therefore,

$$\boxed{Cost\ of\ Rod\ Packing\ Replacement = 92\ X\ \$6{,}000\ X\ 0.367 = \$202{,}548\ per\ Year}$$

Businesses are required to keep records of rod packing leak rates, and make an annual report to ARB.

2. Recordkeeping, reporting, and testing costs are estimated as follows:

Recordkeeping and Reporting Cost = Cost of Businesses Making an Annual Report + Cost of Recordkeeping for Reciprocating Compressors

Where,

Businesses Impacted by Reciprocating Compressor Provision = 55

Cost of Annual Report = $144

Number of Reciprocating Compressors = 979

Cost of Recordkeeping = $48

Therefore,

$$\boxed{Recordkeeping\ and\ Reporting\ Cost = (55\ X\ \$144) + (979\ X\ \$48) = \$54{,}912}$$

$$Total\ Annual\ Cost = Cost\ of\ Rod\ Packing\ Replacement + Recordkeeping\ and\ Reportin\ Cost$$

$$\boxed{Total\ Annual\ Cost = \$202{,}548 + \$54{,}912 = \$257{,}460\ per\ Year}$$

3. Emissions for the Reciprocating Compressor Provision

Emissions were determined using the reciprocating compressor leak rate data provided by industry. According to the data, the average leak rate for all compressors is about 0.9 scfm per cylinder during pressurized operation, and about 0.45 during pressurized idle and unpressurized states. Data from our Oil and Gas Industry Survey indicates that compressors over 250 hp have an average of 3.45 cylinders and operate an average of 6,546 hours per year. Assuming this gas is 78.8% methane, the total emissions for all reciprocating compressors is estimated to be about 7,000 MT of CH4, or about 504,000 MT CO2e using a GWP of 72.

According to the same data from industry, the average leak rate for those compressors emitting more than 2 scfm was about 3 scfm during pressurized operation, and less than 2 scfm during pressurized idle and unpressurized states. This requires the reduction of 1 scfm for the time in pressurized operation to comply with the proposed standard, and calculating reductions in the same fashion as overall emissions, the reduction from this measure is expected to be about 942 MT of CH_4, or about 68,000 MT CO_2e using a GWP of 72.

$$Total\ Volume\ of\ Leaked\ Gas\ (scfm) = Volume\ Leaked\ During\ Pressurized\ Operation + Volume\ Leaked\ During\ Pressurized\ Idle\ and\ Unpressurized\ States$$

$$Volume\ Leaked = Number\ of\ Compressors\ X\ Cylinders\ per\ Compressor\ X\ Leak\ Rate\ per\ Cylinder$$

Where,

Number of Compressors = 325 (ARB, 2013)

Cylinders per Compressor = 3.45 (ARB, 2013)

Leak Rate per Cylinder in Pressurized Operation = 0.9 scfm

Leak Rate per Cylinder in Pressurized Idle and Unpressurized State = 0.45 scfm

Therefore,

Volume Leaked During Pressurized Operation = 325 X 3.45 X 0.9 = 1,009 scfm

Volume Leaked During Pressurized Idle and Unpressurized State = 325 X 3.45 X 0.45 = 505 scfm

$$Volume\ of\ Leaked\ Gas\ per\ Year = Volume\ of\ Leaked\ Gas\ X\ Minutes\ per\ Hour\ X\ Hours\ of\ Operation\ per\ Year$$

Where,

Minutes per Hour = 60

Hours of Pressurized Operation per Year = 6,546 (ARB, 2013)

Hours of Pressurized Idle and Unpressurized State per Year = 2,214 (ARB, 2013)

Therefore,

Volume of Leaked Gas per Year during Pressurized Operation (scfm)= 1,009 scfm X 60 minutes/hour X 6,546 hours = 396,343,935 scf per Year

Volume of Leaked Gas per Year during Pressurized Idle and Unpressurized States = 505 scfm X 60 minutes/hour X 2,214 hours = 67,026,082.5 scf per Year

Total Volume of Leaked Gas per Year = 397,615,433 scf + 67,026,082.5 scf = 463,370,018 scf

$$Mass\ of\ Methane\ (kg) = \frac{Volume\ of\ Leaked\ Gas\ X\ Composition\ of\ Gas\ X\ Molar\ Mass\ of\ Methane}{Conversion\ Factor}$$

Where,

Molar Mass of Methane = 16.04 (API, 2009)

Composition of Gas = 78.8% (API, 2009)

Conversion Factor = 836.2 scf/kg mol (API, 2009)

Therefore,

Mass of Methane = 463,370,018 scf X .788 X 16.04/836.2 = 7,004,036 kg CH4

$$Emissions\ MT\ CO2e = \frac{Mass\ of\ Methane\ (kg) X\ GWP}{1{,}000\ kg/MT}$$

Where,

Conversion Factor = 1000 kg / MT

GWP = 72

Therefore,

$$Emissions\ MT\ CO2e = \frac{7{,}004{,}036\ kg\ CH4\ X\ 72}{1{,}000\ kg/MT} = 504{,}291\ MT\ CO2e$$

4. Reductions

The reductions from the provision for reciprocating compressors is estimated to be about 68,000 MT CO2e. According to our data, the compressors over the proposed standard of 2.0 scfm would only exceed this during pressurized operation, and reductions from pressurized idle or unpressurized states are not accounted for.

$$Volume\ Leaked\ (scfm) = Number\ of\ Compressors\ X\ Cylinders\ per\ Compressor\ X\ Leak\ Rate\ per\ Cylinder$$

Where,

Number of Compressors = 46

Cylinders per Compressor = 3.45 (ARB, 2013)

Leak Rate per Cylinder Above Standard = 3.0 scfm (PG&E, 2015; Sempra, 2015)

Reduction in Leak Rate to Meet Standard = 1.0 scfm

Therefore,

Volume Reduced to Comply with Standard = 46 X 3.45 X 1 = 158.7 scfm

$$Volume\ of\ Leaked\ Gas\ per\ Year = Volume\ of\ Leaked\ Gas\ X\ Minutes\ per\ Hour\ X\ Hours\ of\ Operation\ per\ Year$$

Where,

Minutes per Hour = 60

Hours of Pressurized Operation per Year = 6,546 (ARB, 2013)

Therefore,

Volume of Leaked Gas per Year = 158.7 scfm X 60 minutes/hour X 6,546 hours = 62,331,012 scf per Year

$$Mass\ of\ Methane\ (kg) = \frac{Volume\ of\ Leaked\ Gas\ X\ Composition\ of\ Gas\ X\ Molar\ Mass\ of\ Methane}{Conversion\ Factor}$$

Where,

Molar Mass of Methane = 16.04 (API, 2009)

Composition of Gas = 78.8% (API, 2009)

Conversion Factor = 836.2 scf/kg mol (API, 2009)

Therefore,

$$\boxed{\textit{Mass of Methane (kg)} = 62{,}331{,}012\ scf\ X\ .788\ X\ 16.04/\ 836.2 = 942{,}160\ kg\ CH4}$$

$$Reductions\ MT\ CO2e = \frac{Mass\ of\ Methane\ (kg) X\ GWP}{1{,}000\ kg/MT}$$

Where,

Conversion Factor = 1000 kg / MT

GWP = 72

Therefore,

$$\boxed{Reductions\ MT\ CO2e = \frac{942{,}160\ kg\ CH4\ X\ 72}{1{,}000\ kg/MT} = 67{,}836\ MT\ CO2e}$$

5. Savings from the Reciprocating Compressor Provision

The reduction of 68,000 MT CO2e translates to about 52 million scfm of wholesale quality gas. Reduction in leaks from rod packings directly impact losses from production, and we assume all reductions will count towards savings. Based on data from the U.S. Energy Information Administration (EIA, 2016), we estimate the value of this savings to be \$3.44 per mscf, or about \$178,000.

$$Volume\ of\ Gas\ (scf) = \frac{Mass\ of\ CH4\ (MT)\ X\ Conversion\ Factor}{Molar\ Mass\ of\ CH4\ X\ .949\ X\ 1{,}000\ (\frac{mscf}{scf})}$$

Where,

Mass of CH4 = 942 MT

Conversion Factor = 836.2 kg / k mol

Molar Mass of Methane = 16.04 (API, 2009)

Therefore,

$$\boxed{\begin{aligned} Volume\ of\ Gas\ (scf) &= \frac{942\ MT\ CH4\ X\ 836.2\ \left(\frac{kg}{k} mol\right)\ X\ 1{,}000\ (\frac{mscf}{scf})}{16.04\ X\ .949} \\ &= 51{,}756{,}415\ scf \end{aligned}}$$

$$Value\ of\ Gas\ Saved = Volume\ of\ Gas\ X\ Cost\ per\ mscf$$

Where,

Cost per mscf = $3.44 (EIA, 2015)

1 mscf = 1,000 scf

Therefore,

$$\boxed{Value\ of\ Gas\ Saved\ = \frac{51{,}756{,}415\ scf\ \ X\ \$3.44}{1000\ scf/mscf} = \ \$178{,}042}$$

6. Cost per Ton of the Reciprocating Compressor Provision

Dividing the cost by the emission reductions results in a cost per ton of about $3.80 per MT CO2e reduced. By including savings, the total annual cost of $257,657 is reduced by $178,042, for a net cost of about $80,000 per year. The cost per ton with savings is estimated to be about $1.17 per MT CO2e.

$$Cost\ Per\ Ton\ = \frac{Total\ Cost\ per\ Year\ (\$)}{Total\ Emission\ Reductions\ per\ Year\ (MT\ CO2e)}$$

$$Cost\ Per\ Ton\ with\ Savings = \frac{Total\ Cost\ per\ Year\ (\$) - Savings\ per\ Year}{Total\ Emission\ Reductions\ per\ Year\ (MT\ CO2e)}$$

Therefore,

$$\boxed{Cost\ Per\ Ton\ = \frac{\$257{,}657}{67{,}836\ MT\ CO2e} = \$3.80\text{ per MT CO2e}}$$

$$\boxed{Cost\ Per\ Ton\ with\ Savings = \frac{\$257{,}657 - \$178{,}042}{67{,}836\ MT\ CO2e} = \$1.17\text{ per MT CO2e}}$$

H. Leak Detection and Repair Provision

The proposed regulation requires facilities to implement a Leak Detection and Repair program (LDAR) on their high-methane use components, and conduct inspections on a quarterly basis. To determine the cost of this segment of the measure, staff estimated the number of components that would be inspected, and estimated the cost of performing these inspections.

To determine emissions and cost for LDAR, staff relied on a number of sources for information. Staff used the ARB's 2009 Survey for the number of components and discussions with LDAR contractors for cost information. Estimates for emissions from this segment are derived from emission factors and 'super leaker' data from CAPCOA's Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities (CAPCOA, 1999). According to ARB's Survey (ARB, 2013), there are about 1,307,831 components that will be affected by our proposed regulation. This includes components for facilities involved in natural gas processing, onshore natural gas production, natural gas transmission compressor stations, and natural gas storage. In addition to these components, reciprocating compressors are also part of the LDAR program for our proposed regulation. This represents 979 compressors according to data from our survey. Additionally, there are 20,485 well casings at heavy oil facilities that will be subject to LDAR inspection. Staff assumed there would be 11 components per compressor subject to the LDAR program and that each well casing would count as a component, so the total amount of components becomes about 1,339,185.

1. Costs of the Leak Detection and Repair Provision

The cost to inspect LDAR components was based on discussions with contractors that perform LDAR inspections and repairs. The per hour cost estimates from contractors for LDAR inspections are summarized in Table B-8. This cost is estimated to be $60 per hour for labor, and $1,500 per facility to account for setup costs. In order to derive an annual cost, staff needed to estimate the number of components that could be inspected in an hour. Staff contacted a number of contractors who perform LDAR work and estimated that, on average, about 34 components per hour can be inspected during an eight hour day, when travel and preparation time is accounted for. This also takes into account making a first attempt at a repair if a leak is detected. If accounting only for measurement time, approximately 50 components could be inspected per hour. 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 the business as usual.

Table B-8. Estimated Cost from Contractors

	Estimated Cost per Hour ($ per hour)
Contractor 1	55
Contractor 3	70
Contractor 4	62

Contractor 5	55
Contractor 6	50
Average	**60**

Combining the average inspection rate of 34 components per hour with 2080 work hours per year yields a result of 68,250 components that can be inspected during a person year (PY). Dividing the total number of components, 1,339,185, by the number of components that are able to be inspected in a year, 68,250, yields 19.6, the number of person years needed by our proposed regulation. The total cost is estimated to be $10 million, and is summarized below.

$$\begin{aligned} Cost\ of\ LDAR\ Program &= (Number\ of\ PY\ X\ Cost\ of\ PY) + Setup\ Cost \\ &+ Recordkeeping\ Cost \end{aligned}$$

PY = Number of Components / Components Inspected by One PY

Components Inspected by One PY = Hours per Year X Inspection Rate per Hour

Where,

Inspection Rate per Hour = 34

Labor Hours per Year = 2,080

Therefore,

Components Inspected by One PY = 2,080 Hours per Year X 34 Components per Hour = 68,250 Components per Year

Where,

Number of Components = 1,339,185 (ARB, 2013)

PY = 1,339,185 / 68,250 = 19.6 PY

Annual Cost for a PY = 2,080 Hours X Hourly Rate

Where,

$Hourly\ Rate = \$60$

$$\boxed{Annual\ Cost\ for\ a\ Quarterly\ Inspection = 2{,}080\ Hours\ X\ \$60\ per\ Hour\ X\ 4 = \$499{,}200}$$

$Setup\ Cost = Facilities\ X\ Setup\ Cost\ X\ Capital\ Recovery\ Factor$

$Where,$

$Setup\ Cost = \$1{,}500$

$Capital\ Recovery\ Factor = 0.130$

$$\boxed{Setup\ Cost\ =\ 799\ X\ \$1{,}500\ X\ 0.130\ =\ \$155{,}805}$$

2. Recordkeeping, reporting, and testing costs are estimated as follows:

$Recordkeeping\ and\ Reporting\ Cost = Cost\ of\ Businesses\ Making\ an\ Annual\ Report + Cost\ of\ Recordkeeping\ for\ Inspections$

$Businesses\ Impacted\ by\ LDAR\ Provision = 201\ (ARB,\ 2013)$

$Facilities\ Impacted\ by\ LDAR\ Provision,\ Including\ Well\ Casing\ Facilities = 1{,}054\ (ARB,\ 2013)$

$Cost\ of\ Annual\ Report = \$144$

$Cost\ of\ Recordkeeping = \$48\ X\ 4 = \$192$

$Therefore,$

$$\boxed{Recordkeeping\ and\ Reporting\ Cost = (201\ X\ \$144) + (1{,}054\ X\ \$192) = \$231{,}505}$$

$Therefore,$

$$Cost\ of\ LDAR\ Program = (Number\ of\ PY\ X\ Cost\ of\ PY) + Setup\ Cost + Recordkeeping\ Cost$$

$$\boxed{Cost\ of\ LDAR\ Program = (19.6\ X\ \$499{,}200) + \$155{,}805 + \$231{,}505 = \$10{,}181{,}892}$$

3. Emissions from the LDAR Provision

Emissions were estimated using emission factors from CAPCOA guidelines (CAPCOA, 1999), which also accounted for 'super leaker' components. These are components that leak at a rate several times the rate of what is expected from a typical component, and make up the majority of emissions[9,10,11,12]. Several studies that have reported measurements of CH4 emissions from natural gas production sites share a common observation- the existence of skewed emissions distributions, where a small number of sites or facilities account for a large proportion of emissions. Such skewed distributions can make estimating and attributing emissions more difficult and in turn can impact the effectiveness of emission reduction policies.

Emissions are estimated to be 13,650 MT CH4 per year, or about 982,827 MT CO2e using a GWP of 72. According to the ICF report, a quarterly inspection program is expected to reduce emissions by 60%. Reductions for this LDAR program are estimated to be 8,190 MT CH4 per year, or about 589,680 MT CO2e per year using a GWP of 72.

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[9] Brandt, A. R., et al. 2014. Methane Leaks from North American Natural Gas Systems. Science. Vol. 343,.

[10] Lamb, Brian K., et al. 2015. Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States.

[11] Zavala -Araiza, Daniel, et al. 2015. Reconciling Divergent Estimates of Oil and Gas Methane Emissions. Proceedings of the National Academy of Sciences.

[12] Zavala -Araiza, Daniel, et al. 2015. Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites. Environmental Science & Technology. Vol. 49, Pages 8167−8174.

Table B-9. Emissions from LDAR Components

Fugitive source				
Components <10,000 ppmv	**Number of Components**	**g CH4 per Component per Year**	**MT CH4 per Year**	**MT CO2e Per Year**
Valves	236,131	307	72.49	5,219.4
Connectors	870,766	105	91.43	6,583.0
Flanges	158,486	245	38.83	2,795.7
Open end lines	692	1,288	0.89	64.2
Pump seals	2,312	1,288	2.98	214.4
Others (compressors, hatches, etc)	21,008	1,288	27.06	1,948.2
Components >=10,000 ppmv				
Valves	5,367	1,217,645	6,534.64	470,494.1
Connectors	19,790	226,884	4,490.06	323,284.7
Flanges	3,602	480,924	1,732.27	124,723.2
Open end lines	16	1,208,880	19.02	1,369.4
Pump seals	53	1,208,880	63.53	4,574.4
Others (compressors, hatches, etc)	477	1,208,880	577.17	41,556.5
Total	1,318,700		13,650	982,827

Data from ARB's 2009 Survey, and CAPCOA's California Implementation Guide for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, and API's Fugitive Hydrocarbon Emissions from Oil and Gas Operations. (ARB, 2013[13]; CAPCOA, ARB, 1999[14])

4. Savings from the LDAR Provision

Since gas that is emitted from a leaking component comes directly from the process of production, transmission, processing, or storage, all reductions are counted as savings. Assuming this gas is 94.9 % CH4, staff estimates that about 450 million cubic feet of gas will be saved with the LDAR program of our proposed regulation. Using a price of $3.44 per mscf of gas, this results in a savings of about $1,550,000.

$$Volume\ of\ Gas\ (scf) = \frac{Mass\ of\ CH4\ (MT)\ X\ Conversion\ Factor}{Molar\ Mass\ of\ CH4\ X\ .949\ X\ 1{,}000\ (\frac{mscf}{scf})}$$

Where,

[13] ARB. 2013. ARB 2007 Oil and Gas Industry Survey Results, Final Report, revised in October 2013.

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

Mass of CH4 = 8,190 MT

Conversion Factor = 836.2 kg / k mol

Molar Mass of Methane = 16.04 (API, 2009)

Therefore,

$$Volume\ of\ Gas\ (scf) = \frac{8{,}190\ MT\ CH4\ X\ 836.2\ \left(\frac{kg}{k}mol\right)\ X\ 1{,}000\ (\frac{mscf}{scf})}{16.04\ X\ .949} = 449{,}907{,}765 scf$$

Value of Gas Saved = Volume of Gas X Cost per mscf

Where,

Cost per mscf = $3.44 (EIA, 2015)

1 mscf = 1,000 scf

Therefore,

$$Value\ of\ Gas\ Saved\ = \frac{449{,}907{,}765\ scf\ X\ \$3.44}{1000\ scf/mscf} = \ \$1{,}547{,}683$$

5. Cost per Ton of the LDAR Provision

Cost per Ton is estimated to be about $17.27, or about $14.44 per MT CO2e reduced with savings.

$$Cost\ Per\ Ton\ = \frac{Total\ Cost\ per\ Year\ (\$)}{Total\ Emission\ Reductions\ per\ Year\ (MT\ CO2e)}$$

$$Cost\ Per\ Ton\ with\ Savings = \frac{Total\ Cost\ per\ Year\ (\$) - Savings\ per\ Year}{Total\ Emission\ Reductions\ per\ Year\ (MT\ CO2e)}$$

Therefore,

$$Cost\ Per\ Ton\ = \frac{\$10{,}181{,}892}{589{,}680\ MT\ CO2e} = \$17.27\text{ per MT CO2e}$$

$$\boxed{Cost\ Per\ Ton\ with\ Savings = \frac{\$10{,}181{,}892 - \$1{,}547{,}683}{589{,}680\ MT\ CO2e} = \$14.44 \text{ per MT CO2e}}$$

I. Pneumatic Devices Provision

The proposed regulation requires continuous bleed pneumatic devices to be replaced by no bleed pneumatic devices, and to replace pneumatic pumps with electronic pumps. Staff relied on information from the ICF report, ARB's Survey , API's "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry" (API, 2004) and EPA's "Methane Emissions from the Natural Gas Industry" (EPA, 1996) to determine the number of affected devices, cost, and emissions.

According to ARB's 2009 Survey, there were 1,701 pneumatic devices relating to production, processing, and storage, and 145 pneumatic pumps. 1151 of pneumatic devices were reported to be continuous bleed devices, 405 were intermittent bleed, and 50 were low bleed. Additionally, 31 continuous bleed devices were reported in transmission and distribution, for a total of 1182 continuous bleed devices.

1. Cost of the Pneumatic Devices Provision

EPA's gas star document entitled "Convert Pneumatics to Mechanical Controls" (EPA, 2011) estimates the cost of a no bleed mechanical device to be $3,000 per device. According to the ICF report, the cost of replacing a pneumatic pump is $10,000 with an operating cost of $2,000 per year. These costs were amortized over seven years to reflect the lifetime of the equipment as noted in the ICF report. The total cost to replace these devices is estimated to be about $1.2 million per year, and is summarized below.

$$Cost\ of\ Pneumatic\ Devices = Number\ of\ Devices\ X\ Cost\ per\ Device\ X\ Capital\ Recovery\ Factor$$

Where,

Number of Devices = 1,182 Continuous Bleed Pneumatic Devices (ARB, 2013)

Cost per Device = $3,000 per No Bleed Pneumatic Device (EPA, 2011)

Capital Recovery Factor = .173 from Table B-3

Therefore,

$$\boxed{Cost\ of\ Pneumatic\ Devices = 1{,}182\ X\ \$3{,}000\ X\ 0.173 = \$612{,}749\ per\ Year}$$

$$Cost\ of\ Pneumatic\ Devices$$
$$= Number\ of\ Devices\ X\ (Cost\ per\ Device\ X\ Capital\ Recovery\ Factor$$
$$+ Ongoing\ Cost\ per\ Device$$

Where,

Number of Devices = 145 Pneumatic Pumps (ARB, 2013)

Cost per Device = $10,000 per Pneumatic Pump Replacement (ICF, 2015)

Ongoing Cost per Device = $2,000 per Year (ICF, 2015)

Capital Recovery Factor = .173 from Table B-3

Therefore,

$$\boxed{Cost\ of\ Pneumatic\ Pumps = 145\ X\ (\$3{,}000\ X\ 0.173 + \$2{,}000)}$$
$$\boxed{= \$540{,}560\ per\ Year}$$

$$Total\ Annual\ Cost\ = Cost\ of\ Pneumatic\ Devices + Cost\ of\ Pneumatic\ Pumps$$

$$\boxed{Total\ Annual\ Cost\ = \$612{,}749 + \$540{,}560 = \$1{,}153{,}309\ per\ Year}$$

2. Emissions from the Pneumatic Devices Provision

Emissions were calculated using emission factors used in ARB's 2009 Survey, which included factors from API's "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry" and EPA's "Methane Emissions from the Natural Gas Industry" (EPA, 1996) .

These emission factors are 3.599 tons CH4 per year per device for a continuous bleed device (API, 2004), and 992 scf per million gallons pumped for pneumatic pumps (EPA, 2014). Using these emission factors for the 1182 continuous bleed devices and 145 pneumatic pumps in the production and transmission and distribution segments, the total emissions are 4,437 MT of CH4 or 319,473 MT CO2e using a GWP of 72.

$$Emissions\ for\ Pneumatic\ Devices\ (MT\ CH4)$$
$$= Number\ of\ Devices\ X\ Emission\ Factor$$

Where,

Emission Factor = 3.599 MT CH4/Year/Device (API, 2004)

$$\boxed{Emissions\ MT\ CH4 = 1{,}182\ X\ 3.599\ MT\ CH4/Year/Device = 4{,}207\ MT\ CH4}$$

$$Emissions\ for\ Pneumatic\ Pumps\ (MT\ CH4) = \frac{Emission\ Factor\ X\ Volume\ Pumped\ X\ Molar\ Mass\ of\ CH4}{Conversion\ Factor\ X\ 1{,}000\ kg/MT}$$

Where,

Emission Factor = 992 scf CH4 per million gallons pumped (EPA, 2014)

Volume Pumped = 11,802,226,472 Gallons (ARB, 2013)

Molar Mass of CH4 = 16.04 (API, 2009)

Conversion Factor = 836.2 kg/k mol (API, 2009)

Therefore,

$$\boxed{Emissions\ MT\ CH4 = \frac{992\frac{scf\ CH4}{1{,}000{,}000\ Gallons}\ X\ 11{,}802{,}226{,}472\ Gallons\ X\ 16.04}{836.2\ X\ 1{,}000\ kg/MT} = 224.6\ MT\ CH4}$$

and,

$$\boxed{Emissions\ MT\ CO2e = (4{,}207\ MT\ CH4 + 224.6\ MT\ CH4)\ X\ 72 = 319{,}055\ MT\ CO2e}$$

3. Savings from the Pneumatic Devices Provision

Since these devices are no longer operated by gas, all emissions are reduced. Savings for this segment of the proposed regulation is estimated to be 243 million scf of gas. At a cost of $3.44 per mscf (EIA, 2016), this represents a savings of about $840,000.

$$Volume\ of\ Gas\ (scf) = \frac{Mass\ of\ CH4\ (MT)\ X\ Conversion\ Factor}{Molar\ Mass\ of\ CH4\ X\ .949\ X\ 1{,}000\ (\frac{mscf}{scf})}$$

Where,

Mass of CH4 = 4,431 MT

Conversion Factor = 836.2 kg / k mol

Molar Mass of Methane = 16.04 (API, 2009)

Therefore,

$$\boxed{Volume\ of\ Gas\ (scf) = \frac{4{,}431\ MT\ CH4\ X\ 836.2\ \left(\frac{kg}{k}mol\right)\ X\ 1{,}000\ (\frac{mscf}{scf})}{16.04\ X\ .949} = 243{,}429{,}070\ scf}$$

Value of Gas Saved = Volume of Gas X Cost per mscf

Where,

Cost per mscf = $3.44 (EIA, 2015)

1 mscf = 1,000 scf

Therefore,

$$\boxed{Value\ of\ Gas\ Saved\ = \frac{243{,}429{,}070\ scf\ X\ \$3.44}{1000\ scf/mscf} = \ \$837{,}396}$$

4. Cost per ton of the Pneumatic Devices Provision

Cost per ton is estimated to be $3.61 per MT CO2e reduced, or $0.99 per MT CO2e reduced with savings.

$$Cost\ Per\ Ton\ = \frac{Total\ Cost\ per\ Year\ (\$)}{Total\ Emission\ Reductions\ per\ Year\ (MT\ CO2e)}$$

$$Cost\ Per\ Ton\ with\ Savings = \frac{Total\ Cost\ per\ Year\ (\$) - Savings\ per\ Year}{Total\ Emission\ Reductions\ per\ Year\ (MT\ CO2e)}$$

Therefore,

$$\boxed{Cost\ Per\ Ton\ = \frac{\$1{,}153{,}309}{319{,}055\ MT\ CO2e} = \$3.61 \text{ per MT CO2e}}$$

$$\boxed{Cost\ Per\ Ton\ with\ Savings = \frac{\$1{,}153{,}309 - \$837{,}396}{319{,}055\ MT\ CO2e} = \$0.99 \text{ per MT CO2e}}$$

J. Well Stimulation Provision

For well stimulation circulation tanks, staff relied on industry information and DOGGR data. Based on data from the DOGGR website (DOGGR, 2016), we estimated there would be about 1,200 well stimulation activities during a typical year.

1. Cost of the Well Stimulation Provision

Options to mitigate emissions from a well stimulation activity include using a gas separator plus a low NOx incinerator, which was estimated to cost about $290,000 (Voyager, 2015) and $160,000 (Aereon, 2015a), respectively. Staff estimated that six systems would be needed for well stimulation activities throughout the state, which could be a mix of gas separators, and vapor collection systems. Existing incinerators or a bladder collection system could also be used. For this analysis, six control systems consisting of a gas separator and an incinerator are used, which represents greater cost than other alternatives.

$$\begin{aligned}&Cost\ of\ Well\ Stimulation\ Treatment\\&= Number\ of\ Devices\ X\ (Capital\ Costs\ X\ Capital\ Recovery\ Factor)\end{aligned}$$

Where,

Number of Devices = 6 Gas Separators with 6 Low NOx Incinerators

Cost per Gas Separator = $290,000

Cost per Low NOx Incinerator = $160,000

Installation Cost for Low NOx Incinerator = $80,000

Capital Recovery Factor for Incinerator and Gas Separator = 0.130 from Table B-3

Therefore,

$$\boxed{\begin{aligned}&Cost\ of\ Well\ Stimulation\ Treatment\\&\qquad = 6\ X\ ((\$290{,}000\ X\ 0.130) + (\$160{,}000 + \$80{,}000)\ X\ 0.130)\\&\qquad = \$463{,}350\ per\ Year\end{aligned}}$$

2. Emissions from the Well Stimulation Provision

WSPA provided staff a report on emissions from well stimulation recirculation tanks (WSPA, 2015). Given the limited data set and variability within that data set, staff used the high end of the emissions estimates: 1.26 MT CO2e per event, based on a GWP of 21. Using a GWP of 72, this translates to emissions of about 4.32 MT CO2e per well stimulation. Based on 1,200 well stimulation activities, total emissions are estimated to be about 5,184 MT CO2e per year. Assuming controls are 95% effective, this translates to a reduction of 4,925 MT CO2e per year.

Emissions MT CO2e = Well Stimulation Activities X Emissions per Well Stimulation

Where,

Well Stimulation Activities = 1,200 (DOGGR, 2016)

Emissions per Well Stimulation = 4.32 MT CO2e (WSPA, 2015)

Therefore,

$$\boxed{\text{Emissions MT CO2e} = 1{,}200 \text{ X } 4.32 \text{ MT CO2e} = 5{,}184 \text{ MT CO2e}}$$

3. Savings from the Well Stimulation Provision

Although gas controlled from well stimulation activities may be used or become additional product, for the purposes of this analysis they do not count towards savings.

4. Cost per ton of the Well Stimulation Provision

Using these figures, we estimated the cost of controls for well stimulations. Cost effectiveness is estimated be $90.93 per MT CO2e reduced. The calculation is shown below.

$$Cost\ Per\ Ton = \frac{Total\ Cost\ per\ Year\ (\$)}{Total\ Emission\ Reductions\ per\ Year\ (MT\ CO2e)}$$

Therefore,

$$\boxed{Cost\ Per\ Ton\ = \frac{\$463{,}350}{4{,}925 MT\ CO2e} = \$90.93 \text{ per MT CO2e}}$$

K. Centrifugal Compressor Provision

The proposed regulation requires centrifugal compressors that currently use a wet seal to either convert to using a dry seal, or collect the vented gas emissions with a vapor recovery system. Staff estimated the number of centrifugal compressors with wet seals that would need a vapor recovery system or conversion to a dry seal, and relied on data supplied to us by the operator to determine the cost.

According to ARB's 2009 survey (ARB, 2013), there are 48 centrifugal compressors in California, and 28 of these are equipped with a wet seal. Staff contacted these facilities and found that 27 of these centrifugal compressors had been replaced by a compressor using a dry seal, had installed a vapor recovery system, are no longer in use, reported the wet seal in error, or were operated by a company that is no longer in business. Twenty six centrifugal compressors were reported in ARB's transmission and distribution survey, all of which had dry seals. Based on this information, staff estimated there is only one centrifugal compressor that needs to comply with the proposed regulation.

1. Cost of the Centrifugal Compressor Provision

According to the ICF report, the cost to install a vapor recovery system on a centrifugal compressor is estimated to be about $50,000. Industry provided estimates that confirmed this figure. The cost is amortized over a period of 10 years, which matches the methodology used by ICF. The total cost of installing a vapor recovery system on this centrifugal compressor is estimated to be $6,475 per year.

2. Emissions of the Centrifugal Compressor Provision

To determine the emissions from this compressor, staff again relied on data supplied to us by the operator of the compressor. According to the operator, the emissions measured from this compressor are 1700 scfh or about 28.4 scfm, and operates about 2,000 hours per year.

At an average of 2000 hours per year, 1700 scfh is equivalent to 3,203,520 scf of methane. Total emissions are 51.5 MT CH4, or about 3,700 MT CO2e based on a GWP of 72. According to the ICF report, a reduction of 95% is expected from a vapor recovery unit. This translates to a reduction of 48.9 MT CH4, or about 3,500 MT CO2e.

Where,

$$Leak\ Measurement = 1{,}700\ scf\ per\ Hour$$

$$Hours\ of\ Pressurized\ Operation\ per\ Year = 2{,}000$$

$$\boxed{Total\ Volume\ of\ Leaked\ Gas\ per\ Year = 2{,}000\ Hours\ X\ 1{,}700\ scf\ per\ Hour = 340{,}000\ scf}$$

$$Mass\ of\ Methane\ (kg) = \frac{Volume\ of\ Leaked\ Gas\ X\ Composition\ of\ Gas\ X\ Molar\ Mass\ of\ Methane}{Conversion\ Factor}$$

Where,

Molar Mass of Methane = 16.04 (API, 2009)

Composition of Gas = 78.8% (API, 2009)

Conversion Factor = 836.2 scf/kg mol (API, 2009)

Therefore,

$$\boxed{Mass\ of\ Methane\ = \frac{340{,}000\ scf\ X\ .788\ X\ 16.04}{836.2\ X\ 1{,}000} = \ 51.5\ MT\ CH4}$$

$$Emissions\ MT\ CO2e = \frac{Mass\ of\ Methane\ (kg) X\ GWP}{1{,}000\ kg/MT}$$

Where,

Conversion Factor = 1000 kg / MT

GWP = 72

Therefore,

$$\boxed{Emissions\ MT\ CO2e = \ 51.5\ MT\ CH4\ X\ 72 = 3{,}709\ MT\ CO2e}$$

3. Savings of the Centrifugal Compressor Provision

Since the gas collected from the vapor recovery system is expected to be used or rerouted through their production line, all of the 3.4 million cubic feet of gas that is reduced will count towards savings. Based on data from the U.S. Energy Information Administration (US EIA, 2016), we estimate the value of this savings to be $3.44 per mscf, or about $9,000.

$$Volume\ of\ Gas\ (scf)\ = \frac{Mass\ of\ CH4\ (MT)\ X\ Conversion\ Factor}{Molar\ Mass\ of\ CH4\ X\ .949\ X\ 1{,}000\ (\frac{mscf}{scf})}$$

Where,

Mass of CH4 = 48.9 MT

Conversion Factor = 836.2 kg / k mol

Molar Mass of Methane = 16.04 (API, 2009)

Therefore,

$$Volume\ of\ Gas\ (scf) = \frac{48.9\ MT\ CH4\ X\ 836.2\ \left(\frac{kg}{k}mol\right)\ X\ 1{,}000\ (\frac{mscf}{scf})}{16.04\ X\ .949}$$
$$= 2{,}689{,}090\ scf$$

Value of Gas Saved = Volume of Gas X Cost per mscf

Where,

Cost per mscf = $3.44 (EIA, 2015)

1 mscf = 1,000 scf

Therefore,

$$Value\ of\ Gas\ Saved\ = \frac{2{,}689{,}090\ scf\ X\ \$3.44}{1000\ scf/mscf} = \ \$9{,}250$$

4. Cost per ton of the Centrifugal Compressor Provision

Cost effectiveness is estimated to be about $1.84 per MT CO2e reduced, or a benefit of $0.79 per MT CO2e reduced with savings. The calculation is shown below.

$$Cost\ Per\ Ton\ = \frac{Total\ Cost\ per\ Year\ (\$)}{Total\ Emission\ Reductions\ per\ Year\ (MT\ CO2e)}$$

$$Cost\ Per\ Ton\ with\ Savings = \frac{Total\ Cost\ per\ Year\ (\$) - Savings\ per\ Year}{Total\ Emission\ Reductions\ per\ Year\ (MT\ CO2e)}$$

Therefore,

$$Cost\ Per\ Ton\ = \frac{\$6{,}475}{3{,}524\ MT\ CO2e} = \$1.84 \text{ per MT CO2e}$$

$$Cost\ Per\ Ton\ with\ Savings = \frac{\$6{,}475 - \$9{,}250}{3{,}524\ MT\ CO2e} = -\$0.79 \text{ per MT CO2e}$$

L. Monitoring Plan

Under the proposed regulation, operators of underground natural gas storage facilities will be required to submit a plan for approval that includes daily monitoring of storage wells, and ambient air monitoring. There are a total of 14 underground natural gas storage facilities operated by six businesses that will be impacted by the provision.

There are several options available to operators of these facilities to comply with the proposed regulation. Compliance with the daily monitoring requirement can be accomplished with manual inspection using optical imaging devices, or other leak detecting equipment. Given the cost of this option, it is expected that most operators will choose to use a method of inspecting wells that involves autonomous detection of leaks, which would significantly reduce labor costs.

The cost of these devices was determined through conversations with two businesses that are expected to provide this service. According to the DOGGR website, there are 408 active natural gas storage wells located at the 14 facilities (DOGGR, 2016b). The cost was estimated from a combination of two scenarios; the first using optical imaging cameras mounted on a permanent fixture, and the second using ultrasound monitors in conjunction with optical monitors.

1. Scenario 1

Each facility would need to purchase an OGI camera, and another device capable of detecting leaks. This cost for this equipment was estimated to be $95,000 (ARB, 2016). To conduct daily monitoring, this scenario assumed that wells are not checked manually, but rather with an automated system consisting of two ultrasonic monitors at a cost of $18,500 each, and four IR detectors at a cost of $11,500 each (Caltrol, 2016). These costs are amortized over 10 years.

Cost of Scenario 1 = Annual Cost of Detection Equipment + Annual Cost of Monitoring Equipment + Cost of Manual Inspections + Cost of Ambient Air Monitoring

Annual Cost of Detection Equipment = Number of Facilities X Cost of Equipment X Capital Recovery Factor

Where,

Number of Facilities = 14

Cost of Equipment = $95,000 (ARB, 2016)
Capital Recovery Factor = 0.130

Annual Cost of Detection Equipment = 14 X $95,000 X 0.130 = $172,900

Annual Cost of Monitoring Equipment = Wells X Cost per Well X Capital Recovery Factor

Where,

Wells = 408
Cost per Well = $83,000
Capital Recovery Factor = 0.130

Thus,

Annual Cost of Monitoring Equipment = 408 X $83,000 X 0.130 = $4,402,320

The cost of ambient air monitoring for the Monitoring Plan was based on cost estimates from ARB's Monitoring and Laboratory Division for similar applications. This was estimated to be $84,630 in initial capital cost and $89,500 ongoing cost for each of the 14 affected facilities (ARB, 2016b).

Cost of Ambient Air Monitoring = Number of Facilities X (Amortized Capital Cost + Ongoing Cost)

Cost of Ambient Air Monitoring = 14 X (($84,630 X 0.130) + $89,500) = $1,407,026

Cost of Scenario 1 = $172,900 + $4,402,320+ $1,407,026 = $6,592,207

2. Scenario 2

Each facility would need to purchase an OGI camera, and another device capable of detecting leaks. This cost for this equipment was estimated to be $95,000 (ARB, 2016). To conduct daily monitoring, this scenario assumed that wells are not checked manually, but rather with an automated system consisting of a mounted camera monitor capable of optically detecting leaks. Staff assumed one of these monitors could detect leaks at three wells, and this solution is assumed to be valid for 90% of the wells, with the remaining 10% of the wells still requiring a manual inspection. The cost of this system is estimated at $90,000 per unit, based on conversations with the manufacturer. This cost of manual inspections is estimated at $350 per well per day, and is based on EPA's estimate for inspecting wells using OGI technology (EPA, 2011b). All costs are amortized over 10 years.

Cost of Scenario 2 = Annual Cost of Detection Equipment + Annual Cost of Monitoring Equipment + Ongoing Cost of Equipment + Cost of Manual Inspections + Cost of Ambient Air Monitoring

Annual Cost of Detection Equipment = Number of Facilities X Cost of Equipment X Capital Recovery Factor

Where,

Number of Facilities = 14
Cost of Equipment = $90,000
Capital Recovery Factor = 0.130

$$\boxed{\textit{Annual Cost of Detection Equipment} = 14 \ X \ \$95{,}000 \ X \ 0.130 = \$172{,}900}$$

Annual Cost of Monitoring Equipment = Wells X Cost per Well X Percentage of Applicable Wells X Capital Recovery Factor

Where,

Wells = 408
Cost per Well = $54,000
Percentage of Applicable Wells = 90%
Capital Recovery Factor = 0.130

Thus,

$$\boxed{\textit{Annual Cost of Monitoring Equipment} = \frac{408 \ X \ \$90{,}000 \ X \ 90\% \ X \ 0.130}{3} = \$1{,}432{,}080}$$

$$\textit{Ongoing Cost for Equipment} = \frac{\textit{Wells X Ongoing Cost X } 90\%}{3}$$

Where,

Wells = 408
Ongoing Cost = $18,000

$$Ongoing\ Cost\ for\ Equipment\ = \frac{408\ X\ \$18{,}000\ X\ 90\%}{3}\ =\ 2{,}203{,}200$$

$$Cost\ of\ Manual\ Inspections$$
$$=\ Wells\ X\ Cost\ per\ Well\ X\ Percentage\ of\ Applicable\ Wells\ X\ Frequency\ of\ Inspection$$

Where,
Wells = 408
Cost per Well = $350
Percentage of Applicable Wells = 10%
Frequency of Inspection = 365 times per year

$$Cost\ of\ Manual\ Inspections\ =\ 408\ X\ \$285\ X\ 10\%\ X\ 365 = \$5{,}212{,}200$$

The cost of ambient air monitoring for the Monitoring Plan was based on cost estimates from ARB's Monitoring and Laboratory Division for similar applications. This was estimated to be $84,630 in initial capital cost and $89,500 ongoing cost for each of the 14 affected facilities (ARB, 2016a, ARB, 2016b).

Cost of Ambient Air Monitoring = Number of Facilities X (Amortized Capital Cost + Ongoing Cost)

Cost of Ambient Air Monitoring = 14 X (($84,630 X 0.130) + $89,500) = $1,306,525

Cost of Scenario 2 = $172,900 + $1,432,080 + $2,203,200 + $5,212,200 + 1,306,525 = $10,831,367

Recordkeeping and Reporting Cost = Cost of Businesses Making an Quarterly Report

Businesses Impacted by Monitoring Plan = 6

Cost of Quarterly Report per Year= $576

Therefore,

Recordkeeping = 6 X $576 = $3,459

The total cost of the Monitoring Plan was estimated to be a combination of scenario 1 and scenario 2. Taking the average of the two costs yields an annual cost of about $8,723,290.

$$Cost\ of\ Monitoring\ Plan\ = \frac{Cost\ of\ Scenario\ 1\ +\ Cost\ of\ Scenario\ 2}{2}$$

Cost of Monitoring Plan = ($6,592,207 + $10,831,367) / 2 + $3,459 = $8,723,290

Table B-2 summarizes the costs and reductions associated with the provisions of the proposed regulation.

M. Indirect Costs

While the direct regulatory costs of the proposed regulation can be estimated using the anticipated cost of each control strategy multiplied by the number of units that will be affected, the indirect costs and economic impacts are modeled using a computational general equilibrium model of the California economy known as Regional Economic Models, Inc. (REMI). This analysis was performed and discussed as part of the SRIA (Attachment E). Although the proposed regulation is different than the SRIA analysis, the results and conclusions of the analysis are still relevant given that the anticipated overall cost of the proposed regulation not only remains similar in magnitude to the cost used in the SRIA analysis, but the magnitude of the direct impacts of the proposed regulation as well as the SRIA are small compared to the overall size of the California economy.

N. Alternatives

Staff considered four alternatives to the proposed regulation that would be less burdensome to the affected industry. These alternatives are not the same as the alternatives in the Environmental Analysis, since those alternatives address reducing the environmental impacts of the proposed regulation while these alternatives address Administrative Procedure Act considerations. It is important to note that these alternatives are in addition to those that staff considered at the SRIA phase of this regulation, which are identified in that document. ARB staff conducted a detailed economic analysis only of options 1 and 2, since these were the most viable of the potential alternatives. The clear policy limitations and uncertain costs associated with alternatives 3 and 4 (given their flexible and unknown implementation paths) precluded a more detailed economic evaluation of those options.

1. Alternative 1: No Action. The Oil and Gas Regulation is Not Enacted

The first alternative is to not propose the regulation. Obviously, this would be less burdensome to the industry. However, this alternative does not achieve the goal of reducing methane emissions from the oil and natural gas production, processing, and storage sector. Accordingly, this alternative was rejected.

a) Costs and Benefits

Alternative 1 would impose no additional costs on consumers or manufacturers. In this scenario the impacted sectors would fall under the federal EPA guidelines of 40 C.F.R. Part 60, Subpart OOOO (Quad O).

b) Economic Impacts

Since Alternative 1 does not impose any additional costs to industries or consumers, there would be no economic impacts relative to the current conditions. Compared to the proposed regulation, there would be no changes in GSP, personal income, private investment, or other economic indicators. There would be no reduction of GHG emissions, VOCs, or other airborne toxics.

c) Cost per ton

Alternative 1 has no cost as it does not impose any fiscal costs or regulatory costs that may be associated with the development and enforcement of the proposed amendment.

d) Reason for Rejection

Alternative 1 does not sufficiently meet the goals of the proposed regulation, which is to reduce GHG emissions from the oil and gas industry. Therefore, it is not a viable alternative to the proposed amendment.

2. Alternative 2: Implement the Oil and Gas Regulation Without the LDAR Provision

The second alternative is to not propose the LDAR requirement in the regulation. This provision of the proposed regulation affects the most facilities and can be a labor intensive control measure. However, it also is the provision that achieves the largest amount of emission reductions, accounting for more than a third of the anticipated methane emission reductions. LDAR is also at the heart of catching small leaks before they become larger leaks. In addition, LDAR is key to making sure that other provisions of the regulation are operating properly, such as vapor recovery on separator and tank systems, thereby ensuring that the anticipated emission reductions from those provisions are achieved in practice. For these reasons, this alternative was rejected.

a) Costs and Benefits

If the proposal was adopted with the provisions in the SRIA, the total cost would be about $13.8 million per year, and reduce emissions by about 0.9 million MT CO2e. This includes savings of about $1.5 million per year due to mitigated emissions. Benefits to businesses and individuals would be negligible and commensurate with the current proposed regulation.

b) Economic Impacts

The economic impacts are described in detail in Appendix E, which contains the SRIA and the provisions of the Proposed Regulation. Although this alternative does not include LDAR, the conclusions of the SRIA are still valid, that the proposed regulation was unlikely to significantly impact California’s economy, including the growth of employment, investment, personal income, output, and GSP does not represent a significant change from the BAU scenario.

c) Cost per ton

The cost per ton of Alternative 2 is estimated to be about $15 per MT CO2e reduced, using a GWP of 72. Although this is similar to the cost per ton of the current proposal, alternative 2 does not include LDAR.

d) Reason for Rejection

In addition to being a significant source of reductions, LDAR is also at the heart of catching small leaks before they become larger leaks. Also, LDAR is key to making sure that other provisions of the regulation are operating properly, such as vapor recovery on separator and tank systems, thereby ensuring that the anticipated emission reductions from those provisions are achieved in practice. For these reasons, this alternative was rejected.

3. Alternative 3: Performance-based Standard

Staff considered a performance-standard based alternative for the proposed regulation. Specifically, staff considered a performance-based mandate to regulated entities to reduce the vented and fugitive emissions from regulated sources, as of a date certain, by an amount commensurate with the expected reductions the proposed regulation is expected to produce. Staff rejected this alternative for several reasons, but worked to incorporate flexibilities into the proposed regulation where possible to support legislative direction to avoid prescriptive regulations where possible.

Reasons for rejecting a wholesale performance standard alternative include the following points. This proposed regulation is designed to reduce venting and fugitive emissions from the sector. These emissions are, by their nature, difficult to quantify in many cases, and come from a wide range of potential sources. A flat reduction mandate would be very difficult to enforce without more accurate baseline data on current emissions from these sources, at the facility and component level, than is now available – it is, in other words, far more effective to enforce a requirement to replace a certain piece of equipment, or follow a particular LDAR procedure, than a performance-based reduction requirement from an uncertain baseline. To ensure reductions occur, therefore, staff focused on providing uniform, clear standards for equipment and processes that could reliably be measured, implemented, and enforced. Further, because emission controls focusing solely on methane reduction could have contributed to criteria pollutant emissions if poorly implemented, or failed to secure maximum co-benefits of criteria and toxic pollutants, it was important to specify particular implementation requirements to produce better results on this metric as well.

But though staff rejected a performance standard alternative as a complete option, staff made significant efforts to provide options within the rule's directive framework to provide compliance flexibilities. For instance, regulated entities have several options as to how to implement vapor control device provisions, to conduct LDAR inspections, and to address equipment replacement or retrofit decisions. These embedded options within the proposed regulation help reduce compliance burdens, thereby fulfilling the legislative intent driving consideration of performance-based alternatives, while ensuring that emission reductions happen in an enforceable and environmentally appropriate manner.

4. Alternative 4: Emission Reduction Provision

Staff also considered including an emission reduction provision that would require operators to mitigate climate impacts of large methane leaks. In evaluating whether an emission reduction provision would be appropriate, staff considered several options, including increased penalties for operators of facilities where the leak occurred and an emission reduction plan providing ton-for-ton reductions or stricter monitoring requirements. Staff concluded that stiffer monitoring requirements were the most appropriate. Increased penalties were not an effective option since all prohibited leaks violate the proposed regulation and thus every violation is potentially subject to the maximum penalties statutorily allowed. A plan for reductions was deemed inappropriate at this time, for the following reasons: first, developing generally applicable requirements for such a plan – though somewhat specified in the mitigation plan developed for the Aliso Canyon leak – is a difficult regulatory task when generalized to any potential facility, and so would likely delay the regulation and associated methane reductions.

Furthermore, ARB has considerable authority to drive appropriate mitigation via its existing enforcement authorities and settlement authority. Therefore, rigorous monitoring provisions, rigorously enforced, were deemed appropriate for this proposed regulation. ARB will continue to consider the issue, however, and may revisit this decision in future rulemakings.

O. Fiscal Impacts

The proposed regulation's enforcement and implementation provisions recognize that California's local air districts already play an important role in regulating the oil and gas sector, and are intended to build on their efforts. The provisions make clear that ARB can directly enforce the proposed regulation, but also offer paths for local air districts to integrate its requirements into their existing programs to support efficient and effective enforcement.

ARB's proposed regulation can be implemented and enforced by both ARB and the districts. ARB staff assumes most local air districts will choose to take the lead in implementing and enforcing the regulation, with ARB playing a backstop role, and it is our preference for the local air districts to do so. However, ARB will take a lead role in districts that choose not to. The local air districts are more familiar with operators, conduct inspections nearby or at the same sites, and in many instances have been regulating such sources for decades. This is why the regulation allows local districts to enter into MOUs with ARB in order to define implementation and enforcement responsibilities, as well as for information sharing. The regulation also allows for districts to incorporate this regulation into their local rules. To ensure uniform enforcement, however, districts may not waive or reduce the stringency of the state rules, which remain state law, enforceable as necessary by ARB.

ARB staff estimates that the regulation will require 6 PYs to implement depending on the mix of district and ARB implementation. In addition to PYs, ARB will need to purchase equipment including three IR cameras at $85,000 each, and three toxic vapor analyzers at $10,000 each. The costs are higher with ARB enforcement than with district enforcement due to the need to travel, train new staff, and set-up programs including a registration program. The total cost to ARB is estimated to be $285,000 in initial costs ((3 X $85,000) + (3 X $10,000)), and about $870,000 in ongoing costs (6 X $145,000). These costs are anticipated to be imposed during the 2017/2018 fiscal year.

1. Other State Agencies

The proposed regulation does not affect other state agencies.

2. Air Districts

A local air district may decide – but is not obligated -- to be the primary agency responsible for enforcing the provisions of the Proposed

Regulation. This includes issuing permits for new control equipment, registration and inspection of equipment, and enforcing the LDAR portion of the regulation. The individual district cost estimates range from amounts some districts feel could be absorbed by them without additional funding, to over $300,000 per year in recurring costs and almost $1,000,000 in one-time costs, primarily for permitting. Even if the districts do decide to implement and enforce this regulation, there is an annual cost for ARB to manage the reporting requirements in the regulation. The costs to districts are estimated to be approximately $1,300,000 in initial costs, and approximately $660,000 in ongoing costs.

Although local agencies (air districts) may choose to implement this regulation, and certain aspects of it may be incorporated in permits as a matter of preexisting law, resulting in some fiscal impacts, the regulation imposes no reimbursable mandates. Air districts face no new legal requirements specific to them under this regulation. As to implementation tasks they may take on or any other costs that may result by operation of statute, air districts have legal authority under Health and Safety Code sections 40510 and 42311 to recover related costs by imposing fees. The Proposed Regulation also specifies that local air districts that choose to enforce the regulation may retain any penalty monies that result. ARB also may make arrangements to further support air districts as a voluntary matter. Thus, because the regulation applies generally to all entities operating affected sources, not the air districts, and so does not impose unique new requirements on local agencies, this is not a reimbursable mandate. (*County of Los Angeles v. State of California*, 42 Cal. 3d 46 (1987).

The proposed regulation's enforcement and implementation provisions recognize that California's local air districts already play an important role in regulating the oil and gas sector, and are intended to build on their efforts. The provisions make clear that ARB can directly enforce the proposed regulation, but also offer paths for local air districts to integrate its requirements into their existing programs to support efficient and effective enforcement. ARB's proposed regulation can be implemented and enforced by both ARB and the districts. ARB staff assumes most local air districts will choose to take the lead in implementing and enforcing the regulation, with ARB playing a backstop role, and it is our preference for the local air districts to do so. However, ARB will take a lead role in districts that choose not to. The local air districts are more familiar with operators, conduct inspections nearby or at the same sites, and in many instances have been regulating such sources for decades. This is why the regulation allows local districts to enter into MOUs with ARB in order to define implementation and enforcement responsibilities, as well as for information sharing. The regulation also allows for districts to incorporate this regulation into their local rules. To ensure uniform enforcement, however, districts may not waive or reduce the stringency of the state rules, which remain state law, enforceable as necessary by ARB.

DEPARTMENT OF FINANCE

EDMUND G. BROWN JR. • GOVERNOR

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May 28, 2015

Ms. Emily Wimberger
Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Ms. Wimberger:

Thank you for submitting the standardized regulatory impact assessment (SRIA) and the summary (Form DF-131) for the proposed regulations on reducing greenhouse gas emissions from crude oil and natural gas operations, as required in California Code of Regulations, title 1, section 2002(a)(1).

Based on the April 22, 2015 draft regulations, sources at oil and natural gas production, processing, and storage facilities would be required to reduce methane in support of AB 32—Global Warming Solutions Act of 2006. Affected facilities are expected to achieve compliance through installations of equipment by 2018. Other requirements such as periodic testing, reporting, and recordkeeping of methane and hydrocarbon emissions; and timely repair of leaking components would take effect by 2017. Requirements at each facility would depend on existing equipment and local air district requirements on the same sources. While local authorities would have some flexibility, these proposed regulations are an attempt to bring all facilities up to a minimum standard.

In addition to the health and environmental benefits to individuals, industries that supply control devices benefit when the regulated facilities purchase equipment to comply with the new standards. According to the SRIA, the annualized cost of the proposed regulations peaks at $18.8 million in 2017, assuming the affected facilities can amortize the costs. This, together with equipment spending, would result in an increase of $54.3 million in gross state product, thus meeting the major regulations threshold of $50 million a year. There would, however, be small reductions overall in growth rates of gross state product thereafter.

Finance, in general, concurs with the methodology used to assess the economic impact of the proposed regulation. The SRIA was particularly well constructed in relating the direct impacts of the proposed regulation to the overall impacts. However, it would helpful to include the magnitude of the unit and total costs of devices and the geographical distribution of the affected facilities. Since the majority of retrofit costs are expected to occur in 2018, the highest direct cost and economic impact should occur in 2018, not in 2017 as described in the SRIA. While the SRIA does comply with the requirement to discuss alternatives, it would be helpful to include the direct cost of each alternative in the SRIA, rather than just the overall impacts. Finally, ARB may want to discuss how an individual facility's characteristics, such as emission rates and existing control devices, may affect the calculation of direct costs, and thus economic impacts of the proposed regulations. These existing efforts also determine the amount of emissions reductions that would be achieved.

These comments are intended to provide sufficient guidance outlining revisions to the SRIA. The SRIA, a summary of Finance's comments, and any responses must be included in the rulemaking file that is available for public comment. Finance understands that the proposed regulations may change during the notice of proposed action, after the public comment period, and following the ARB Board hearing. If any significant changes to the proposed regulations result in economic impacts not discussed in the SRIA, please note that the revised economic impacts must be reflected on the Standard Form 399 for the rulemaking file submittal to the Office of Administrative Law. Please let us know if you have any questions regarding our comments.

Sincerely,

Irena Asmundson
Chief Economist

cc: Ms. Panorea Avdis, Governor's Office of Business and Economic Development
Ms. Debra Cornez, Office of Administrative Law
Ms. Trini Balcazar, Air Resources Board
Ms. Chantel Crane, Air Resources Board
Ms. Elizabeth Scheehle, Air Resources Board
Mr. Craig Segall, Air Resources Board

Response to DOF Comments

Comment #1

It would be helpful to include the magnitude of unit and total costs of devices, and the geographical distribution of the affected facilities.

Most of the affected facilities are in the San Joaquin Air Pollution Control District. According to ARB's 2009 survey, over 60% of the affected LDAR components are located in the San Joaquin APCD. Other districts with a significant amount of affected facilities include Santa Barbara APCD, South Coast APCD, Feather River APCD, and Glen County APCD. The magnitude of unit and total costs of devices is described in detail in the cost analysis section of this Appendix.

Comment #2

Since the majority of retrofit costs are expected to occur in 2018, the highest direct cost and economic impact should occur in 2018, not in 2017.

The standards were set to be effective January 1, 2018 and it was anticipated that the capital costs would occur prior to that, in 2017. Since the effective date of the standards requiring the purchase of capital equipment has been changed to 2019, the majority of retrofit and other capital equipment is estimated to take place in 2018.

Comment #3

Include the direct cost of each alternative in the SRIA, rather than just the overall impacts.

At the time of the SRIA, the first alternative included a requirement that existing continuous-bleed pneumatic devices to be replaced with no-bleed devices. It also required an LDAR inspection program with quarterly inspections. These alternatives were eventually incorporated into the existing proposed regulation. The direct costs for this alternative were estimated to be about $28 million per year with an emissions reduction of about 500,000 MT CO_2e. The second alternative eliminated the LDAR provision, the centrifugal compressor provision, and added a leak standard for rod packing replacement. This alternative was estimated to cost about $20 million per year with an emissions reduction of about 450,000 MT CO_2e. Since the SRIA, better data has become available and through development of the regulation, several of the provisions have changed, and incorporated parts of each alternative. Due to these changes, a direct comparison of the costs and emissions is difficult to make.

Comment #4

Discuss how an individual facility's characteristics, such as emission rates and existing control devices, may affect the calculation of direct costs, and thus economic impacts of the Proposed Regulations.

Generally, the emission rates and number of affected devices are proportional to the estimated cost of compliance. Some facilities, which may not be subject to an existing LDAR program, may exhibit greater emissions than those that are under an existing LDAR program for VOC. These facilities may have a greater amount of emissions, or super leaking components. This would increase the cost minimally, but would be more cost effective.

Some facilities may also have an existing flare connected to a separator and tank system. In these cases, the flare would need to be removed to install a low NOx incinerator. This would be an additional cost for these facilities. The impact is expected to be minimal. Facilities with a tank and separator system with emissions under 10 tons per year of CH_4 emissions would not be required to install vapor recovery and would have less overall cost than facilities with greater than 10 tons per year of CH_4 emissions.