Attachment 2

Summary of Cost, Emissions, and Cost per Ton using the 20 year and 100 year GWP, respectively

Provision	Annual Cost	Annual Savings	Reductions using 20 year GWP (MT CO2e)	Cost per Ton using 20 year GWP ($ / MT CO2e reduced)	Cost per Ton using 20 year GWP with Savings ($ / MT CO2e reduced)	Cost per Ton using 100 year GWP ($ / MT CO2e reduced)	Cost per Ton with Savings using 100 year GWP ($ / MT CO2e reduced)
VRU for Tanks	$4,700,000	$500,000	540,000	$9	$8	$25	$23
Reciprocating Compressors	$260,000	$180,000	68,000	$4	$1	$11	$3
LDAR	**$12,900,000**	**$1,300,000**	**490,000**	**$26**	**$23**	**$75**	**$68**
Pneumatic Devices	$1,200,000	$840,000	320,000	$4	$1	$10	$3
Well Stimulations	$460,000	$0	5,000	$91	$91	$262	$262
Centrifugal Compressors	$6,000	$9,000	3,500	$2	($1)	$5	($2)
Monitoring Plan	**$10,600,000**	$0	0	NA	NA	NA	NA
Total	**$30,100,000**	**$2,800,000**	**1,400,000**	**$21**	**$19**	**$62**	**$56**

Notes:

Bolded numbers indicate changes from the ISOR.

The cost for the LDAR provision went up by almost 30% due to: 1) the cost of inspecting idle wells, which, although already covered under the regulation, was not included in the ISOR Economic Analysis; and 2) using a higher, stakeholder-supplied cost for recordkeeping and reporting. The emission reductions and annual cost savings from gas saved both went down less than 20%, due to correcting the reductions based on the methane content of the gas saved. The cost per MT of CO2e reduced increased accordingly due to the cost and emission reduction changes described above.

The cost for the Underground Natural Gas Storage Monitoring Plan provision went up by more than 20% due to: 1) the addition of a third stakeholder-supplied scenario; 2) higher cost estimates for ambient monitoring equipment; and 3) using a higher, stakeholder-supplied cost for recordkeeping and reporting across all scenarios.

The proposed regulation's overall total costs, savings, reductions, and cost per MT of CO2e reduced all changed accordingly due to all of the changes described above.

Revised emission and cost estimates for the Leak Detection and Repair provision

The proposed regulation requires oil and gas facilities to implement a Leak Detection and Repair program (LDAR) for their components, conducting 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 costs for LDAR, staff relied on a number of sources for information. Staff used ARB's 2009 Survey (ARB, 2013) 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 the 2009 ARB Survey (ARB, 2013), there are about 1,307,931 components that will be affected by the proposed regulation. This includes components for facilities involved in natural gas processing, onshore natural gas production, and natural gas storage. Reciprocating compressors are also part of the LDAR program for our proposed regulation, including compressors at natural gas transmission compressor stations. Based upon assumptions resulting from stakeholder input there would be 11 components per compressor subject to the LDAR program; thus, 979 reciprocating compressors are assumed to have a total of 10,769 components.

Owners and operators are also required to measure natural gas flow from well casing vents located in the field. Accordingly, in order to account for the costs of going into the field for measuring and reporting well casing vent emissions, staff assumed that each well casing vent would count as a component, even though they are not subject to LDAR, but do still have costs comparable to the per-component costs previously mentioned. As a result of assumptions made from stakeholder input, an estimated 20,485 components from well casing vents at heavy oil facilities were added to the component total in the ISOR. Because this is only a reporting requirement, no emissions or reductions were associated with the well casing vent components, so these are not included in the emission calculation. These component counts and costs were accounted for and identified in the ISOR on pages B-34 through B-41.

In addition to these components, idle wells will be inspected. There are an estimated 877 idle wells for dry gas and gas storage and 4,368 idle wells for light oil. Based on data from EPA's 2011 TSD for Oil and Natural Gas sectors, which was the best available data for component counts at a single well site, 9 valves, 37 connectors and 1 open ended line were attributed to each well. This added 41,219 components for the idle dry gas and gas storage wells, and 205,296 components for the idle light oil wells. The total amount of components is 1,585,700, as shown in Table 1.

Table 1

Number of Components

LDAR Components from Survey	1,307,931
Reciprocating Compressors	10,769
Well Casing Vents	20,485
Idle Dry Gas and Gas Storage Wells	41,219
Idle Light Oil Wells	205,296
Total	1,585,700

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 of the ISOR. 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 estimated the number of components that could be inspected in an hour. As stated in the ISOR, 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 accounting for travel and preparation time. 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 business as usual. Thus only those repairs that are made on a first attempt are accounted for in this estimate, and are reflected in the 34 components per hour value.

Given the estimated average inspection rate of 34 components per hour combined with an estimated person year (PY) at 2,080 work hours per year, a total of 70,720 components that can be inspected during a PY. The total number of PYs required to inspect the components identified in Table 1 is determined by dividing the total number of components by 70,720, then multiplying by four to account for a quarterly inspection. About 89.7 PYs would be needed to inspect the 1,585,700 components quarterly.

Recordkeeping and reporting costs are estimated using ICF's cost estimate for an LDAR program (ICF, 2014). The recordkeeping and reporting estimate is $15,000 for each PY for an annual program. Since the ARB program is quarterly, the ICF annual

figure is multiplied by four, and then multiplied by the number of PYs estimated above at 89.7. The total recordkeeping and reporting cost is about $1.3 million annually.

This differs from the recordkeeping and reporting costs in the ISOR, which were estimated by multiplying a small cost per recordkeeping and reporting event by the number of businesses or facilities impacted. The ISOR estimate was less than 20% of the $1.3 million figure explained above. This change in the method of estimating recordkeeping and reporting costs was based on stakeholder input.

Emissions

Emissions were estimated using emission factors from CAPCOA's 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[1,2,3,4]. 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 821,314 MT CO2e, and reductions are expected to be about 492,789 MT CO2e using a GWP of 72. Reductions are 60% of the total emissions for quarterly inspections, as estimated in the 2014 ICF report.[5] Detailed LDAR emission estimates are included in Tables A-1, A-2, and A-3 at the end of this text.

Emissions were initially calculated in the ISOR using the emission factors for total hydrocarbons, but have been modified by taking into account the estimated methane content by multiplying these results by 78.8%, which is the default amount of methane in production gas (API, 2009).

The emissions and costs are summarized in Table 2.

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

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

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

[4] 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.

[5] The ICF report cites research by Colorado and EPA as the basis for this reduction. The EPA citation is the 2011 Technical Support Document for Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for the Final New Source Performance Standards. This document then references EPA's 1995 Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017

Table 2

Cost and Emissions for LDAR

	Number of Components	Emissions (MT CO2e)	Reductions (MT CO2e)	Quarterly Inspection Cost	Set Up Cost	Recordkeeping and Reporting	Total Cost
Dry Gas, Gas Storage and Gas Processing	1,339,185	774,468	464,681	$9,453,071	$1,198,500	$1,136,186	$10,864,912
Idle Dry Gas and Gas Storage Wells	41,219	23,122	13,873	$290,958	$36,889	$34,971	$334,413
Idle Light Oil Wells	205,249	23,724	14,234	$1,448,816	$183,687	$174,137	$1,665,201
Total	**1,585,653**	**821,314**	**492,789**	**$11,192,845**	**$1,419,076**	**$1,345,294**	**$12,864,526**

The Quarterly Inspection cost is calculated as:

$$Inspection\ Cost = \frac{Number\ of\ Components\ X\ \$60\ per\ hour\ X\ 2080\ hours\ per\ year\ X\ 4\ inspections\ per\ year}{70{,}720\ Components\ per\ PY}$$

The Set Up cost is calculated as:

$$Set\ Up\ Cost = \frac{\$1{,}500\ per\ facility\ X\ Number\ of\ Components\ X\ 799\ Facilities}{1{,}339{,}185\ Components\ from\ Survey}$$

The Recordkeeping and Reporting cost is calculated as:

$$Recordkeeping\ and\ Reporting\ Cost = \frac{\$15{,}000\ X\ 4\ X\ Number\ of\ Components}{70{,}720\ Components\ per\ PY}$$

<u>Savings from the LDAR Provision</u>

Since gas that is emitted from a leaking component comes directly from the process of production, processing, transmission, or storage, all reductions are counted as cost savings. Converting the methane reductions into saved pipeline natural gas by assuming pipeline gas is 94.9 % CH4 (PG&E, 2016), staff estimates that about 375

million standard cubic feet (scf) of gas will be saved with the LDAR program in the proposed regulation. Using a price of $3.44 per mscf of pipeline gas results in a savings of about $1,293,380.

Cost per Ton of the LDAR Provision.

Cost per Ton is estimated to be about $26 per MT CO2e reduced, or about $23 per MT CO2e reduced with savings, using a GWP of 72. This increased from the estimates of $17 per MT CO2e reduced and $14 per MT CO2e reduced with savings, which are identified in the ISOR. This increase is due to an increase in recordkeeping and reporting costs, adjusted reductions based on methane content, and the inclusion of components from idle light oil wells, which have fewer emissions and reductions than dry gas production, underground gas storage, and gas processing components. Cost effectiveness with savings was determined by subtracting the amount of savings from the estimated total cost.

Local Air District Costs

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. Originally, the cost to districts was estimated to be approximately $1,300,000 in initial costs in the first year, and approximately $660,000 in annual ongoing costs. Since this estimate made in the ISOR, components from idle wells were added, bringing the total number of components to 1,585,700 from 1,339,185, representing an 18.5% increase. Assuming there would be a corresponding proportional increase in district costs, an 18.5 % increase brings the estimated cost to districts to $1.54 million in initial costs, and $780,000 in ongoing costs.

Table A-1
Emissions of LDAR Components from the ISOR

Emission Factors of Fugitives % of Components that are High Leaking 2.22%

Fugitives source					
Components <10,000 ppmv	g CH4 per Component per Year	Number of Components	Total g CH4 per Year	MT CH4 per Year	MT CO2e Per Year
Valves	241.92	236,131	57,123,958	57.12	4,112.9
Connectors	82.74	870,766	72,047,168	72.05	5,187.4
Flanges	193.06	158,486	30,597,316	30.60	2,203.0
Open end lines	1014.94	692	702,612	0.70	50.6
Pump seals	1014.94	2,312	2,347,002	2.35	169.0
Others (compressors, hatches, etc.)	1014.94	21,008	21,321,492	21.32	1,535.1
Well Casings		20,485	-		-
Components >=10,000 ppmv			-		-
Valves	959504.26	5,367	5,149,296,884	5,149.30	370,749.4
Connectors	178784.59	19,790	3,538,170,914	3,538.17	254,748.3
Flanges	378968.11	3,602	1,365,026,296	1,365.03	98,281.9
Open end lines	952597.44	16	14,987,533	14.99	1,079.1
Pump seals	952597.44	53	50,064,288	50.06	3,604.6
Others (compressors, hatches, etc.)	952597.44	477	454,812,356	454.81	32,746.5
Total		**1,339,185**	**10,756,497,818**	**10,756**	**774,468**
Reductions 60%				**6,454**	**464,681**

Table A-2
Emissions of LDAR Components from Idle Dry Gas and Gas Storage Wells

Emission Factors of Fugitives % of Components that are High Leaking 2.22%

Fugitives source					
Components <10,000 ppmv	g CH4 per Component per Year	Number of Components	Total g CH4 per Year	MT CH4 per Year	MT CO2e Per Year
Valves	241.92	7,718	1,867,011	1.87	134
Connectors	82.74	31,728	2,625,167	2.63	189
Flanges	193.06	0	-	-	-
Open end lines	1014.94	858	870,326	0.87	63
Pump seals	1014.94	0	-	-	-
Others (compressors, hatches, etc.)	1014.94	0	-	-	-
	0.00		-		-
Components >=10,000 ppmv	0.00		-		-
Valves	959504.26	175	168,297,047	168.30	12,117
Connectors	178784.59	721	128,919,583	128.92	9,282
Flanges	378968.11	0	-	-	-
Open end lines	952597.44	19	18,565,066	18.57	1,337
Pump seals	952597.44	0	-	-	-
Others (compressors, hatches, etc.)	952597.44	0	-	-	-
Total		**41,219**	**321,144,200**	**321**	**23,122**
Reductions 60%				**193**	**13,873**

Table A-3
Emissions of LDAR Components from Light Oil Idle Wells

Emission Factors of Fugitives % of Components that are High Leaking 0.86%

Fugitives source					
Components <10,000 ppmv	g CH4 per Component per Year	Number of Components	Total g CH4 per Year	MT CH4 per Year	MT CO2e Per Year
Valves	104.92	38,965	4,088,354	4.09	294.4
Connectors	55.22	160,189	8,846,147	8.85	636.9
Flanges	132.54	0	-	-	-
Open end lines	99.40	4,329	430,353	0.43	31.0
Pump seals	1463.41	0	-	-	-
Others (compressors, hatches, etc.)	723.42	0	-	-	-
	0.00		-		-
Components >=10,000 ppmv	0.00		-		-
Valves	390426.89	338	131,966,554	131.97	9,501.6
Connectors	129221.91	1,390	179,564,109	179.56	12,928.6
Flanges	1435799.04	0	-	-	-
Open end lines	122595.15	38	4,604,208	4.60	331.5
Pump seals	491485.06	0	-	-	-
Others (compressors, hatches, etc.)	39208.36	0	-	-	-
Total		**205,249**	**329,499,726**	**329**	**23,724**
Reductions 60%				**198**	**14,234**

Revised Cost Estimates for the Natural Gas Underground Storage Facility Monitoring Requirements Provision

Under the proposed regulation, operators of underground natural gas storage facilities will be required to submit a plan for approval that includes continuous or daily monitoring of storage wells, and continuous 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. According to DOGGR, there are 452 active natural gas storage wells located at the 14 facilities (DOGGR, 2016).

The cost estimate for this provision uses three possible scenarios to estimate the cost of implementation. Implementation includes four major costs: continuous ambient air monitoring, daily or continuous wellhead monitoring, repairs, and recordkeeping. The cost estimates for each scenario and the average of the three is presented in Table 1.

Continuous Ambient Air Monitoring

Staff anticipates that the ambient monitoring stations that are used to detect methane concentrations and installed to comply with the ambient air monitoring requirements will be similar to ARB stations currently in use.

Scenario 1 uses a cost estimate provided by SoCal Gas (SoCal Gas, 2016). The cost of ambient air monitoring is estimated to be $400,000 per facility with an ongoing cost of $52,000 per year. This $52,000 includes estimated costs for maintenance, calibration, spare parts, etc., assumes an estimated 5% of monitors are replaced each year, and includes $10,000 for annual operation and maintenance per monitor. The SoCal Gas cost estimate also included a cost for labor to respond to false alarms triggered by the monitoring system on a continuous basis. Staff is proposing to add into the regulation an appropriate baseline and threshold to trigger an alarm, based on stakeholder comments. Because this proposed revision will prevent these false alarms, this cost has been excluded.

The cost estimate for the ambient air monitoring for scenarios 2 and 3 is estimated as the costs that are currently in use by existing ARB monitoring stations. These monitoring stations, employing a device such as a Piccaro methane detector, would be used to detect methane concentrations in the ambient air at the facility. Based on conversations with ARB's Monitoring and Laboratory Division (MLD) which already uses such devices, the cost of one of these detectors is estimated at $175,000 with $89,500 ongoing costs (ARB, 2016). Two stations were assumed to be needed at each facility at a capital cost of $350,000 and an ongoing cost of $179,000 per facility.

Daily or Continuous Wellhead Monitoring

Compliance with the continuous or daily well monitoring requirement can be accomplished with a manual inspection using Method 21, optical gas imaging (OGI)

devices, or other leak detection equipment. Given the higher cost of manual inspection, it is expected that most operators will choose to use an automated detection method, which would significantly reduce labor costs. This could involve a sensor, OGI cameras, or other technology. The cost was estimated using a subset of these devices based upon conversations with two businesses that are expected to provide this service. The cost was estimated for three scenarios; the first using OGI cameras based on a cost estimate provided by SoCal Gas; the second using ultrasonic monitors in conjunction with optical monitors; and the third based on using OGI cameras mounted on a permanent fixture. The second two were included in the original ISOR Economic Analysis but have been updated based upon input from stakeholders. All capital costs are amortized over 10 years, which is consistent with the amortization period of most other capital equipment used to comply with the provisions of the regulation.

Scenario 1 uses a cost estimate provided by SoCal Gas. The cost of the capital equipment is estimated to be $77,000 per well. This represents 2 pairs of IR model 5500 cameras at each well plus a 10% contingency. SoCal Gas notes that this is a conservative installed cost. An ongoing cost of $5,000 is estimated for maintenance of the OGI cameras, calibration, reporting, data review, and data compilation for external audiences. This $5,000 estimate assumes 5% of equipment is replaced each year plus $3,500 annual operation and maintenance per well.

SoCal Gas also provided an estimate that was based on manual inspections using OGI cameras at an estimated $17.3 million in labor per year for all 452 wells. Since ARB anticipates that operators will choose to have an automated system for performing these inspections, this estimate was not included in this analysis.

Similarly, Scenario 2 assumes that wells are not checked manually, but rather with an automated system. This scenario is based on conversations with a manufacturer of an ultrasonic monitor. This estimate assumes that three ultrasonic monitors at a cost of $20,000 each, and three IR detectors at a cost of $11,500 each (Caltrol, 2016) would be used at each well, for a total cost of $94,500 per well. An ongoing cost of $5,000 annually per well is assumed for this scenario.

Scenario 3 assumes that the well monitoring is completed with an automated system. This scenario is based on a cost estimate of installing OGI cameras mounted on a fixed platform to continuously monitor wells. These are estimated to cost $90,000 each (Pixel, 2016), and be able to detect leaks at three wells, and be able to cover 90% of the wells at a facility. The remaining 10% of wells would need to be inspected manually, and this was estimated to cost $123,839 for each of the 14 facilities. This estimate is found by taking the SoCal gas estimate for performing manual inspections using OGI cameras for all wells ($17,336,788), multiplying it by 0.1 to obtain an estimate for 10% of wells only, then dividing the cost among the 14 facilities.

Recordkeeping and Reporting

Recordkeeping and reporting costs were assumed to be the same in all three scenarios. The total cost for recordkeeping and reporting was provided by SoCal Gas, and is estimated to be $1,385,360. This includes the annual cost of reporting ($20,800) for each of six business, as well as recordkeeping ($83,200) for each of 14 facilities. In addition, for each facility there is a one-time amortized cost of $20,000 for monitoring plan development and an annual $4,000 cost for monitoring plan updates.

Repairs

Consistent with ARB's LDAR cost estimates, the cost estimates for Scenarios 2 and 3 do not include repair costs, assuming that these are repairs that would be made by the operator as part of regular facility maintenance, and the monitoring simply alerts the operator to this need. SoCal Gas however, estimates that the capital and labor costs to screen and repair detected leaks, and the materials to repair these leaks, should be included. This annual cost is estimated to be $134,682 per facility (SoCal Gas, 2016). We included the cost of repairs in Scenario 1 to show the SoCal Gas estimate in full, but do not believe those are extra costs attributable to the proposed regulation.

Total Annualized Cost

Total annual costs for each scenario are calculated by the following equations with the values in Table 1.

$$J = (D\ X\ A\ X\ C) + (E\ X\ A) + (F\ X\ B\ X\ C) + (G\ X\ B) + (H\ X\ A) + I$$

For Scenario 1

$$(\$400{,}00\ X\ 14\ X\ .13) + (\$52{,}000\ X\ 14) + (\$77{,}000\ X\ 452\ X\ .13) + (\$5{,}000\ X\ 452) + (\$134{,}682\ X\ 14) + (\$1{,}385{,}360) = \$11{,}511{,}428$$

For Scenario 2

$$(\$350{,}00\ X\ 14\ X\ .13) + (\$179{,}000\ X\ 14) + (\$94{,}500\ X\ 452\ X\ .13) + (\$5{,}000\ X\ 452) + (\$0\ X\ 14) + (\$1{,}385{,}360) = \$12{,}341{,}180$$

For Scenario 3

$$J = (D\ X\ A\ X\ C) + (E\ X\ A) + (F\ X\ B\ X\ C)/3 + (G\ X\ A) + (H\ X\ A) + I$$

$$(\$350{,}00\ X\ 14\ X\ .13) + (\$179{,}000\ X\ 14) + \left(\frac{\$90{,}000\ X\ 452\ X\ .13}{3}\right) + (\$123{,}834\ X\ 14) + (\$0\ X\ 14) + (\$1{,}385{,}360) = \$8{,}024{,}836$$

Table 1

Cost Estimate of Monitoring Plan Provision

		Scenario 1	Scenario 2	Scenario 3	
A	Facilities	14	14	14	
B	Wells	452	452	452	
C	Capital Recovery Factor	0.13	0.13	0.13	
D	Capital Cost of Ambient Air Monitoring Equipment per Facility	$400,000	$350,000	$350,000	
E	Ongoing Cost of Ambient Air Monitoring Equipment per Facility	$52,000	$179,000	$179,000	
F	Capital Cost of Well Monitoring Equipment	$77,000 per well	$94,500 per well	$90,000 per 3 wells	
G	Ongoing Cost of Well Monitoring Equipment	$5,000 per well	$5,000 per well	$123,834 per facility	
H	Ongoing Cost for Repairs per Facility	$134,682	NA	NA	
I	Total Recordkeeping and Reporting	$1,385,360	$1,385,360	$1,385,360	
J	Total Annual Cost	$11,511,428	$12,341,180	$8,024,836	Average of the three scenarios $10,625,815

External Scientific Peer Review of the Flash Analysis Test Procedure

https://www.arb.ca.gov/cc/oil-gas/peerreview/peerreview.htm