Comments Received during the Public Review Period on the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014

Commenter: Pamela Lacey
American Gas Association (AGA)

Comment: Meter and Regulator Stations

AGA is pleased that EPA has followed through on its proposal in the Distribution Memo to revise estimated emissions from metering and regulating (M&R) stations by incorporating updated station counts and emission factors from the Lamb et al. study. As we commented before, AGA believes that EPA's proposal to use the updated emission factors and the above grade and below station counts our members report to EPA under 40 C.F.R. Part 98, Subpart W and scaled for national representation results in a more accurate estimate of the actual number of M&R stations.

As we noted in our January comments, we agree that it makes sense to estimate M&R emissions across the time series by using the new updated emission factors for years after 2011 when the Subpart W data became available, to use the 1992-vintage GRI emission factors for early years beginning in 1990, and to use interpolation for the years in between. We agree this is the best approach to more accurately reflect net emissions without the need to subtract Gas STAR program emission reductions.

Comment: Pipeline Leaks

For estimated pipeline leaks in the Draft Inventory, EPA used the previous activity data sources for miles of pipeline by material and for leaks per mile, and the Lamb et al. data on emissions per leak. AGA agrees with this approach, and particularly supports EPA's incorporation of the Lamb et al. pipeline emission factors. As AGA noted in its prior comments, numerous regulatory developments and voluntarily operator actions have resulted in significant reductions in leak rates and incidents, reflected in the overall lower emissions found in the Lamb et al. study. AGA also agrees with EPA's approach to use interpolation between GRI/EPA emission factors in early years and Lamb et al. emission factors in recent years.

Comment: **Residential** Customer Meters

AGA supports EPA's inclusion in the Draft Inventory of revised emission factors for residential customer meters by combining data from the 1996 GRI/EPA study with newer data from a GTI 2009 study and Clearstone 2011 study. As noted in previous comments, the newer data sources, and in particular the GTI 2009 study, include a robust data set composed of numerous data points representing a variety of residencies, including single family homes, duplexes, townhouses, and apartment buildings. Given the homogeneity of the residential meters found at all the distribution companies sampled through the GTI 2009 study, incorporating the new residential meter factor into the GHGI is appropriate.

AGA also supports EPA's update of its customer meter activity data for residential meters to incorporate customer data reported to the U.S. Energy Information Administration (EIA). The customer data is

reported to EIA on its Form EIA-176. EIA does not collect data on meters specifically. Rather, EIA instructs respondents to report the average number of consumers served directly from facilities during the year. For residential consumers, this includes master-metered apartments, mobile homes, multi-family dwellings (individually metered), and single-family dwellings. Using data reported to the EIA will improve accuracy compared to the previous GHGI methodology of using 1992 counts driven by gas consumption.

Comment: Commercial & Industrial Meters

AGA is pleased to see that for commercial and industrial meters, EPA has applied the GTI 2009 commercial customer meter emission factor to the total count of commercial and industrial meters in the GHGI. As AGA noted in its prior comments, consistent with EPA's approach in the Draft Inventory, the GTI 2009 industrial meter data should not be incorporated into the GHGI. The GTI 2009 study only took industrial meter measurements from a limited number of sites (46 meters). Due to limited resources, measurements of industrial meters were intended to represent the broad range of meters in this sector, but do not provide a statistical sampling indicative of the industrial meter national inventory, nor does it account for the significant variance in equipment type and size in industrial meters. For this reason, AGA agrees with EPA not to include this data into the GHGI.

AGA also supports EPA's update of its customer meter activity data for commercial and industrial meters to incorporate customer data reported to the EIA. As explained above, the customer data is reported directly to the EIA. Using this data will improve accuracy compared to the previous GHGI methodology of using 1992 counts driven by gas consumption.

Comment: Blowdowns and Mishaps/Dig-Ins

For pipeline blowdowns and mishaps/dig-ins, in the Draft Inventory EPA used PHMSA data of distribution main and service miles for the activity data to calculate the estimate of emissions. Although AGA appreciates EPA's attempt to update the methodology used to calculate emissions from pipeline blowdowns and mishaps/dig-ins, AGA does not believe that EPA's approach provides an accurate representation of the emissions from these sources.

As EPA recognizes, the current approach taken in the GHGI for both sources, which relies on 1992 distribution main and service miles and is scaled by residential gas consumption, results in a mileage estimate that is influenced by factors that would impact natural gas usage, but are unrelated to pipeline miles. AGA agrees with EPA that PHMSA data is a more accurate data source of pipeline miles. Pipeline operators are required to report data directly to the Department of Transportation on an annual basis, which renders the PHMSA data on pipeline mileage an accurate representation of installed pipeline mileage and is superior to the current methodology of estimating pipeline mileage.

However, AGA is concerned with EPA's use of pipeline miles to estimate emissions from blowdowns and mishaps/dig-ins. These sources of emissions are discrete events and there is no available data that suggests a correlation between the number of miles in a pipeline system and the number of mishap events on that system. The number of reported pipeline incidents on gas distribution systems has been flat or down during the past five years; during that time, from 2010 to 2014, the number of miles of installed distribution main in the U.S. has increased by nearly 60,000 miles or 5%.

AGA encourages EPA to use activity data that reflects the reality that an emission blowdown or mishap/dig-in is a discrete event that is not correlated to the number of miles in a pipeline system. AGA recognizes the difficulty in obtaining a comprehensive set of data for these sources of emissions. However, because data associated with both will be reported through EPA's proposed Methane Challenge for companies selecting this best practice, EPA will have more data for possible use in the future to generate activity data for the GHGI. In addition, for mishaps/dig-ins, AGA notes that significant incidents are reported to PHMSA, where significant is defined as an incident above a certain size or impact threshold. [Incidents on natural gas distribution systems are defined as an event that involves a resale of gas from a pipeline that results in a death or significant personal injury, property damage of $50,000 or more, or 3 million cubic feet of lost gas. 49 C.F.R. § 191.3.] AGA recommends consideration of incident data reported to PHMSA and data collected through the Methane Challenge as possible alternative data sources for development of more representative activity data for mishaps/dig-ins.

Comment: New Methodology Obviates Need to Subtract Gas STAR Reductions

In the past, EPA used emission factors based on data collected in 1992 in an EPA-Gas Research Institute (GRI) Study. The agency recognized that practices and materials changed over time, as companies modernized their systems and implemented best practices shared through the Gas STAR program. EPA thus considered the 1992 vintage emission factors to reflect the potential emissions sources could emit in the absence of modernization, and the agency attempted to reflect the effect of continuing modernization by subtracting voluntary reductions reported under the Gas STAR program to calculate net emissions from the sector.

AGA agrees that the new methodology – using new data, including that collected in 2013 from the March 2015 Lamb et al. study and Subpart W reporting – results in a more accurate representation of current operations practices and emissions levels. We agree this obviates the need to continue subtracting voluntary emission reductions achieved through the Gas STAR program to estimate current emission levels for M&R stations, pipeline leaks, and customer meters, since the new data already reflects current practices and emission levels.

Comment: AGA Also Generally Supports the Use of New Data and Methodology for Estimating Methane Emissions from Natural Gas Transmission and Storage

EPA's revisions to the GHGI for the natural gas transmission and storage segment primarily rely upon Zimmerle et al. and an interpolation of existing and new data between the early and current inventory years. Although AGA believes that these approaches can serve as an interim step in EPA's GHGI, AGA encourages EPA to recognize the significantly larger data set available from measurements conducted at transmission and storage compressor stations subject to Subpart W of the GHG Reporting Program. For example, the Subpart W data could be evaluated to assess the relative population of wet seal versus dry seal centrifugal compressors. AGA also believes that Subpart W data can provide a more accurate representation of activity data and device type for pneumatic controllers. AGA encourages EPA to commit to additional updates to the 2017 GHGI report that would integrate Subpart W data.

Commenter: Cynthia A. Finley
National Association of Clean Water Agencies (NACWA)

Comment: NACWA has submitted comments on each of the previous nine Inventories, and we appreciate the clarifications that EPA has made to clarify the emissions calculations and the factors that are used in the calculations. Although the wastewater treatment section has not yet been updated for the 2014 Inventory, EPA states that the same methodology will be used as in the previous Inventory. NACWA previously stated its concern that potentially outdated data was used in the emissions calculations (e.g., the 2004 Clean Watershed Needs Survey). If the same data is used in the 2014 Inventory, our concern remains that the calculations may not accurately reflect current wastewater utility practices. NACWA also believes that more specific emissions factors could be developed for U.S. wastewater treatment.

NACWA understands that EPA will be looking at possible improvements for the wastewater treatment calculations in the next year. NACWA is willing to assist EPA in any way with these improvements, such as providing general information about current wastewater practices or collecting specific data from our member utilities.

Commenter: Evan Weber, William Snape, Lydia Avila, Colette Pichon Battle, Joan Brown, Andres Restrepo, Alan Journet, Erik Schlenker-Goodrich
U.S. Climate Plan, Center for Biological Diversity, Energy Action Coalition, Gulf Coast Center for Law & Policy, New Mexico Interfaith Power and Light, Sierra Club, Southern Oregon Climate Action Now, Western Environmental Law Center

Comment: We respectfully submit these comments on the Draft U.S. Greenhouse Gas Inventory Report: 1990-2014. Our comments are intended to encourage EPA to examine gross U.S. greenhouse gas (GHG) emissions using the most updated values of the Global Warming Potential (GWP) of methane and nitrous oxide. Given recent international news on China's underreporting of its coal consumption and, accordingly, GHG emissions (a November 3, 2015 New York Times article estimates the undercounting at over 900 million metric tons), we believe that the U.S. should place additional importance on accurately quantifying its own GHG emissions.

Our comment states that the Inventory Report, in Annex 6.1, uses an alternative set of GWPs [from the Intergovernmental Panel on Climate Change's 5th Assessment Report (AR5)] that exclude carbon cycle feedbacks, resulting in emissions estimates lower than if EPA were to include these feedbacks. While we understand that EPA excludes these feedbacks to align methodology with the GWPs used in the main text of the Inventory Report, we believe that these higher emissions estimates, which represent the full climate impact of methane and nitrous oxide, must be presented to the public.

It is our goal to increase the transparency by which the EPA reports U.S. GHG emissions to the global community. We believe that using GWPs inclusive of carbon cycle feedbacks accomplishes this goal.

Comment: In Section 6.1 of the U.S. GHG Inventory, Table A-282 presents alternative scenarios of greenhouse gas emissions estimates if EPA used GWPs from the IPCC Fifth Assessment Report (AR5), rather than the Fourth Assessment Report (AR4). However, this analysis underestimates the GWP of CH_4

and N_2O, based on Table 8.7 (page 714) of the AR5 Working Group I report. This underestimation results from excluding "carbon cycle feedbacks" previously not quantified in AR4. Table 1 shows that by including these feedbacks for AR5 100-year GWPs, the emissions increase (relative to AR4 values) is far higher than EPA presents. While EPA reports this increase to be 22.6 (0.3% higher than AR4 total emissions) $MMTCO_2e$, the true value is 238.0 (3.5% higher) $MMTCO_2e$. According to WRI's CAIT tool, this additional 215.4 $MMTCO_2e$ is roughly equal the gross emissions of Norway, Sweden, Denmark, and Finland—combined.

Our analysis does not include the following factors, which we believe indicate that our upward adjustments are actually conservative:

- IPCC indicates that the GWP of biogenic methane is 34, whereas fossil methane is 36, over a 100-year time horizon. Given that over one-third of U.S. methane emissions are fossil (from natural gas systems, coal mining, and petroleum systems), the change in methane from AR4 to AR5 should be greater than our value of 254.8.
- EPA's also underestimates the GWP of HFC-134a, which represents 40% of Emissions from Substitution of Ozone Depleting Substances – the AR5 value EPA uses is 1,300, whereas IPCC, including carbon cycle feedback, uses 1,550. Other high-GWP gases, whose carbon cycle feedbacks are not quantified in Table 8.7, very likely have higher GWPs than EPA uses in Annex 6.1, though the lack of IPCC data prevents us from quantifying this.

These emissions must be presented to the public. We do understand that EPA has chosen not to include the carbon cycle feedbacks from CH_4 and N_2O for the AR5 GWPs in order to align methodologies with AR4. However, given that the GWPs highlighted yellow in Table 1 below are the "true" values, we see no reason to keep the lower AR5 numbers, as changes in methodology to quantify carbon cycle feedbacks are precisely the goal of updated scientific research. If consistency between methodologies really is necessary (though again, this shouldn't be a reason not to use the higher values), then we recommend communicating these findings in addition to the previous ones. Table 2 presents the GHG emissions totals by gas, for further transparency as to how we calculated the differences between emissions for each GWP accounting method.

Table 1 - Changes in Emissions using AR4 GWPs, AR5 GWPs Excluding Climate Feedbacks, and AR5 GWPs Including Climate Feedbacks

GHG	AR4 GWP - Inventory	AR5 GWP - Inventory	2014 Change from AR4 to AR5 – no Carbon Cycle Feedback	% Change	AR5 GWP - IPCC	2014 Change from AR4 to AR5 – Carbon Cycle Feedback Included	% Change
CO_2	1	1	0.0	0%	1	0.0	0%
CH_4	25	28	84.9	12.0%	34	254.8	36%
N_2O	298	265	-45.6	-11.1%	298	0.0	0%
HFCs	MIXED	MIXED	-16.4	-9.3%	MIXED	-16.4	-9.3%
PFCs	MIXED	MIXED	-0.6	-9.6%	MIXED	-0.6	-9.6%
SF_6	22,800	23,500	0.2	3.1%	23,500	0.2	3.1%
NF_3	17,200	16,100	0.0	-6.4%	16,100	0.0	0%
Total			**22.6**	**0.3%**		**238.0**	**3.5%**

Table 2 - GHG Emissions Totals by Gas using IPCC's AR4, EPA's AR5, and IPCC's AR5 GWPs

GHG	2014 Emissions (AR4)	2014 Emissions (AR5, excluding carbon cycle feedbacks)	2014 Emissions (AR5, including carbon cycle feedbacks)
CO2	5,564.3	5,564.3	5564.3
CH4	707.9	792.8	962.7
N2O	411.4	365.8	411.4
HFCs	175.8	159.4	159.4
PFCs	5.8	5.2	5.2
SF6	6.9	7.1	7.1
NF3	0.6	0.6	0.6
Total	**6,872.7**	**6,895.3**	**7,110.7**

Commenter: Brad Upton
National Council for Air and Stream Improvement, Inc. (NCASI)

Comment: The estimated forest ecosystem carbon stock changes reported in the draft 1990-2014 national inventory are significantly different than those reported previously. The text in the report explains that this is due, at least in part, to new estimation methods (described in Woodall et al. 2015) and reclassification of land in Alaska. It is our understanding that the new estimates rely more heavily on measured data (compared to model-generated data) than earlier estimates and, as a result, are likely to be more accurate. It would be helpful for the text in the report to elaborate on the benefits of greater reliance on measured vs. modeled data in the updated estimates.

Comment: While the report contains a summary of the recalculations of forest ecosystem carbon, it is unfortunate that the annexes have not been updated to provide a full explanation of the sources of the difference between the new and previous estimates. We encourage the agency, in future years, to make the annexes available for comment at the same time the report is made available.

Comment: Changes in carbon stocks in products-in-use are also significantly different than in previous inventories, but this is not acknowledged or explained in the report or the annexes. This should be discussed in the report and examined in more detail in the annexes.

Comment: In Chapter 7 Waste on page 7-11, line 1, EPA states that the degradable organic carbon (DOC) value for landfilled pulp and paper waste was revised from 0.20 to 0.15 based on a literature review and data reported under 40 CFR Part 98 (referred to as the Greenhouse Gas Reporting Program, GHGRP, the new DOC value is also discussed in Chapter 9 Recalculations and Improvements on page 9-1, line 39, and in Annex 3.14 on page A-391, line 38). The new value of 0.15 corresponds to a weighted average of all DOC values reported to the GHGRP within subpart TT by pulp and paper facilities in 2013. It is stated in a reference supporting the draft inventory (RTI 20152) that 72% of the pulp and paper facilities that reported to subpart TT used only the default DOC values from Table TT-1 and that 49% of the reported waste quantities were associated with the default DOC value for general pulp and paper industry waste other than industrial sludge (0.20). Therefore, the new DOC value used in the draft inventory (0.15) is heavily influence by use of the default value of 0.20 in Table TT-1.

The current default DOC for general pulp and paper industry waste other than industrial sludge in Table TT-1 (0.20) is based on an erroneous interpretation of IPCC guidance, as documented by NCASI in prior communications with EPA (NCASI 20113). Therefore, it is inappropriate to include data elements corresponding to the default value of 0.20 when developing a new DOC value for use in the inventory. As noted in RTI 2015, 28% of pulp and paper facilities that reported to subpart TT developed DOC values specific to their landfilled waste streams by analysis using methodologies specified by EPA. It is more technically appropriate (and accurate) to develop a DOC value for pulp and paper industry waste from a weighted average of these waste stream-specific DOC values reported to the GHGRP, as these values represent the characteristics of the actual waste placed in industrial landfills at pulp and paper mills and would not be influenced by the erroneous general DOC value of 0.2. RTI 2015 presents such a weighted average DOC value for pulp and paper industry wastes, which is 0.10. EPA should use a DOC value of 0.10 rather than 0.15 in developing estimates of methane emissions from industrial landfills at pulp and paper mills.

Comment: In Annex 3.14 on page A-391, line 38, EPA incorrectly associates the new DOC value for pulp and paper industry waste (0.15) with an L_0 value of 49 m^3/MT. An L_0 value of 49 m^3/MT correlates with a DOC value of 0.10, which is the technically appropriate DOC value to use in the agency's top down analysis as explained above. On line 47 the agency states that "data were available through the GHGRP to warrant a change to the L_0 (DOC) from 99 to 49 m^3/MT…" Note that the previous DOC (0.20) is correlated with an L_0 of 99 m^3/MT, and further note that DOC is directly proportional to L_0. Therefore, halving L_0 (from 99 to 49 m^3/MT) would result in DOC also being halved (i.e., from 0.20 to 0.10).

Comment: As conveyed in our comments on the public review Draft US Inventory of Greenhouse Gas Emissions and Sinks: 1990-2013 (included herein as Appendix A), production statistics developed by EPA for use in waste-related GHG emissions calculations for the pulp and paper sector are too high. Table 7-12 lists 2013 production of the pulp and paper sector at 131.5 million metric tons, based on data from the Food and Agriculture Organization of the United Nations (FAO), and includes a note that this figure represents the sum of woodpulp production plus paper and paperboard production. The same production figures are presented in RTI 2006, which describes EPA's method for estimating industrial landfill emissions. Summing woodpulp, paper, and paperboard production results in double counting, because the majority of woodpulp production is used to produce paper and paperboard at integrated mills (an integrated mill includes both pulping and papermaking at the same facility).

A more appropriate method for characterizing total pulp and paper sector production would be to sum paper production, paperboard production, and market pulp production [Market pulp is produced at a pulp mill and then sold rather than being used at the same mill to produce paper or board]. For 2013, the American Forest and Paper Association reported total production of paper and paperboard to be approximately 73 million metric tons and total production of market woodpulp to be approximately 8 million metric tons (AF&PA 2014). Based on these statistics, total pulp and paper sector production in 2013 was approximately 81 million metric tons.

EPA's method of using the FAO statistics overstates the pulp and paper industrial sector's production, which in turn results in estimates of pulp and paper sector industrial wastewater treatment and landfill methane emissions being far too high. On page 7-28 of the Draft US Inventory of Greenhouse Gas Emissions and Sinks: 1990-2014, lines 42-47, EPA notes that the agency is evaluating new approaches to estimating industry-level production (and other values) used in estimating industrial wastewater treatment GHG emissions. The agency should use production data from AF&PA's Statistical Summary reports in calculating both wastewater treatment and landfill emissions from the pulp and paper sector, which will result in more accurate characterization of industrial waste-related methane emissions from this sector.

Commenter: Michael Schon
Portland Cement Association (PCA)

Comment: The Draft Inventory's approach to accounting for emissions associated with cement production does not consider available data, however, or determine whether those data are consistent with the conclusions reached by the Draft Inventory. In addition, the Draft Inventory does not present a comprehensive and easily discernible estimate of the industry's total GHG emissions. This issue makes verification of the total emissions associated with cement production impossible and also masks

efficiency improvements by the sector. In these comments, PCA suggests areas for improvement to address these concerns.

Comment: As the Draft Inventory acknowledges, GHG emissions are released at two points in the production of cement—an essential component of concrete. First, the combustion of fuel to heat cement kilns and to enable necessary chemical reactions produces GHG emissions. Thanks to efficiency improvements, including use of carbon-neutral alternative fuels, cement production plants reduced combustion-related emissions per unit of production in recent years. Second, emissions are generated through calcination, a chemical reaction that produces calcium oxide—a foundational component of cement. Calcium carbonate is converted to calcium oxide and carbon dioxide: $CaCO_3$ -> $CaO + CO_2$. There is little opportunity to reduce the calcination process- related CO_2 emissions per unit of production.

Comment: EPA developed a Greenhouse Gas Reporting Program (GHGRP) for cement plants to inventory both of these types of emissions on a facility-specific basis. Under Subpart H to 40 C.F.R. Part 98, all cement production plants in the United States must report both their combustion-related and process-related emissions. 40 C.F.R. §§ 98.80, 98.82. EPA now has five years of reported data from those facilities on file. In 2010, an Intergovernmental Panel on Climate Change (IPCC) task force encouraged the consideration of GHGRP data in the development of the annual inventory of domestic GHG emissions that EPA submits to the United Nations in accordance with the United Nations Framework Convention on Climate Change (UNFCCC).

Yet this year's draft domestic inventory, like its predecessors, still does not consider the GHGRP data for cement production, including whether those data points are in line with the GHG estimations presented in the Draft Inventory. Rather, EPA punts on considering those data. This is a missed opportunity to evaluate facility-specific data, as EPA itself acknowledges.

Comment: In the Draft Inventory, EPA also misses an opportunity to analyze emissions associated with cement production in a comprehensive manner. While the process-related emissions of cement production are addressed in the Industrial Processes and Product Use chapter of the Draft Inventory, the combustion-related emissions of cement production are not disaggregated from other industries' combustion-related emissions in the Energy chapter. The Draft Inventory estimates total process-related cement production emissions at 38.8 MMT CO_2e in 2014, but presents no equivalent figure for the combustion-related cement production emissions. This makes it impossible to determine the total emissions generated by the industry.

Thus, PCA cannot comment on whether the Draft Inventory's accounting of cement production emissions is defensible or accurate. We encourage EPA to calculate and present an overall emissions figure associated with cement production so that it can be compared to the total reported cement production emissions of 67.6 MMT CO_2e in 2014 under the GHGRP.

Comment: PCA also encourages EPA to consider cement production emissions not only on a total mass basis but also on a production rate basis so that efficiency improvements are apparent. As economic conditions have improved, demand for cement has increased, resulting in an increase in the total tons of emissions. Importantly, however, significant efficiency improvements, on an emissions per unit of production basis, have also occurred.

Commenter: Kerry Kelly
Waste Management (WM)

Comment: We have gained considerable experience by implementing the Mandatory GHG Reporting Rule (GHG MRR) since 2010, reporting emissions for active and closed Municipal Solid Waste (MSW) landfills and associated renewable energy projects. The landfill sector has significant interest in the Draft Inventory since EPA, for the first time has used annual waste disposal data reported by MSW landfills under Subpart HH of the GHG MRR, in its Draft Inventory emissions estimates. We very much want to work with you to ensure that GHG MRR data are used correctly to refine the Draft Inventory for MSW landfill emissions.

We commend EPA for using GHG MRR data to refine the inventory estimates of emissions. As EPA states in Chapter 7 –Waste, of the Draft Inventory (at 7-7), the EPA rigorously verifies data provided by reporters subject to the GHG MRR. Moreover, reporters certify the data as true and accurate before submitting it to the Agency, and must collect data and ensure its quality in accordance with GHG MRR requirements and the facility's GHG Monitoring Plan. Thus, data developed for the GHG Reporting Program (GHGRP) is of known quality and has far greater certainty than other databases EPA has relied upon. Using reporting data and emissions calculations prepared for the GHGRP should enhance the quality and validity of the nationwide inventory.

Comment: Because of the emphasis on accuracy and verification with GHG MRR data, we were surprised with the changes to MSW landfill emissions estimates in the Draft Inventory. We believe that thorough evaluation of the databases must be undertaken before EPA can confidently express 2015 emissions using the GHG MRR data. The changes in net emissions, and amounts of methane flared and used for energy appearing in the draft inventory are very significant and negative. The 24-year methane reduction performance achieved by MSW landfills working to comply with EPA control standards dropped from a projection of 38% reduction to a mere 1.4% reduction. We could not replicate the Agency's calculations, and they appear to be in contravention with other data all agree to be reliable.

Specifically, there appears to be a fundamental disconnect between the estimated emissions reported by MSW landfills subject to the GHGRP and the estimated emissions reported in the Draft Inventory. The GHGRP emissions from MSW Landfills in 2014 were 91.5 MMT CO_2e. EPA designed the GHGRP to obtain the highest possible percentage of emissions from each reporting sector, while minimizing the total number of facilities that would be required to report. EPA selected a reporting threshold for MSW landfills based on estimated methane generation of 25,000 MT CO_2e or greater, and estimated that the MSW landfills reporting under GHGRP comprise 82% of total national emissions of MSW landfills for both active and closed landfills.

The inconsistency in the emissions reported becomes evident when comparing the 2014 emissions from the GHGRP to those estimated in the Draft Inventory for the same year. If 91.5 MMT represents 82% of MSW landfill emissions, then logically, the total from all MSW landfills will be approximately 111.5 MMT CO_2e. Instead, total emissions from MSW landfills are 167 MMT CO_2e, and emissions for the landfill sector (both MSW and industrial landfills) are 181.8 MMT CO_2e.

Comment: The landfill sector representatives appreciated your meeting with us to describe the process used to integrate GHGRP annual waste disposal figures into the Draft Inventory. Since we first reviewed these estimates, we have been attempting to discover what factors led to a total methane generation of almost twice as much as what was in the GHGRP data. This is a challenging exercise because the

database has been structured in such a way to make accessing all of the relevant information very difficult.

Comment: We found a significant source of error in the use of GHGRP annual waste disposal figures in the Draft Inventory because the waste was not properly differentiated between degradable waste and inert materials. Since only degradable waste produces methane, applying the degradation factor (or DOC) for bulk MSW to all waste disposed (even separate inert waste streams that do not degrade) significantly over predicts methane generation.

We looked first at the public database for the GHGRP (Envirofacts) to assess how many reporters in 2014 characterized their annual waste receipts to identify inert materials. Because Envirofacts does not capture the waste type descriptor provided by reporters, one must query the database to identify reporters using various DOC values for different waste streams and sum those fractions to one. For 2014, 944 landfill sites reported accepting waste. Of those 944 reporting annual waste receipts, 42% reported receiving inert waste, using the waste composition option to delineate inert wastes (DOC=0), and combining separate C&D waste streams with MSW under the bulk waste category, or by using the modified bulk waste option showing (MSW DOC=0.31 C&D DOC=0.08, Inert DOC=0).

In fact, because it is so difficult to identify reported waste types in Envirofacts, we turned to the SCS Engineers database, which contains all required reporting elements from 2010-2014 for 544 MSW landfill GHGRP reporters, or 44% of the total number of reporters, and 50% of the annual waste receipts. The landfills in this database include both private and municipal sites located across the country. Looking at GHGRP annual disposal amounts for the 544 sites in 2014, 23% of waste disposed was reported as inert. The prior reporting years 2010-2013, had similar percentages of waste reported as inert (ranging from 17% in 2010 to 22.5% in 2013), with the amount of inert waste growing in each year. This is consistent with the current emphasis on diversion of organic wastes from landfills, and efforts by landfills to make up the difference with inert waste streams such as ash and soils.

We also evaluated the GHGRP waste disposal history for these 544 sites (including total waste in place -- WIP). Of the total WIP, 8.1% is inert. However, WIP data is far less definitive than annual waste disposal information because most reporters did not have historical data, or chose to estimate historical waste in place as MSW and did not characterize the different waste streams (MSW, C&D, inert) disposed in the landfill.

Waste Management did report well-characterized waste back to 1999 for most sites. A review of this information showed that from 1999 through 2015, there has been a 21.5% drop in the amount of MSW waste disposed in landfills, a 21% increase in inert wastes, and an 11% increase in C&D waste. These findings comport with the experience of public and private landfills across the country. Increased recycling and organics diversion initiatives have resulted in a decline in MSW landfill disposal, yet for many landfills receipt of inert waste streams has steadily increased.

Based on our analysis of the three datasets, we believe the annual waste disposal volumes used in the Draft Inventory to calculate methane generation were likely assigned inappropriately high DOC values, resulting in an over prediction of methane generation. This in turn led to inflated estimates of methane emissions from MSW landfills.

Comment: We know that you share our interest in assuring the final Inventory is as accurate as possible. The information in the Draft Inventory presents major, adverse policy implications for the Administration

and EPA. The current draft could be interpreted to contradict White House and Agency regulatory statements, plans and documents with regard to methane controls, vitiate the effectiveness of the EPA's twenty-year old New Source Performance Standards (NSPS) and Emission Guidelines (EG) Rules, and undermine the accomplishments of the Landfill Methane Outreach Program (LMOP). These very serious impacts must certainly be avoided if they result from a misinterpretation of GHGRP waste disposal data because the inventory database simply does not fully characterize waste types and their potential to generate methane over time.

The landfill sector wants to work with you to ensure that the GHGRP data are appropriately used, and the resulting estimated emissions are representative of MSW landfill disposal and gas collection and control practices. We are concerned that there is limited time for the Agency to conduct a thorough reevaluation of the data and make the necessary changes. If the Agency were to publish the Draft Inventory results as they appear in the current draft, public officials and community residents would be misinformed about landfill emissions, and there could be significant policy and economic repercussions for the sector.

To allow sufficient time for correction of the draft estimate, in the short-term, we urge EPA to use the 2015 Inventory data and protocols for estimating MSW landfill emissions. For future inventories, we encourage the Agency to make use of the emissions calculations developed and certified by GHGRP reporters under the force of law. The Agency has been proactive in improving the estimation of landfill methane emissions by updating GHGRP protocols. Use of these verified emissions data could only enhance the U.S. Inventory, while reducing administrative burdens on Agency staff. We urge EPA to work with the landfill sector to develop a methodology to incorporate GHGRP results and the growing body of measured methane emissions into the nationwide inventory – much as you are doing with the natural gas sector. We believe this is a wise practice, and we commit to do everything possible to assist your review.

Commenter: Luis Orlindo Tedeschi

Texas A&M University

Comment: I know this is past the date of March 23, 2016, but I really wanted to make sure this is addressed. I noticed in Table 5-3, the order of Horses, Sheep, and Swine might be incorrect. Looking at previous reports, you had Swine, Horses, and Sheep, and the numbers for the current inventory don't match my expectations. I'd think that Swine is greater than horses and sheep, and sheep is greater than horses.

DRAFT, 1990-2014 Inventory Report:

Table 5-3: CH_4 Emissions from Enteric Fermentation (MMT CO_2 Eq.)

Livestock Type	1990	2005	2010	2011	2012	2013	2014
Beef Cattle	119.1	125.2	124.6	121.8	119.1	118.0	116.7
Dairy Cattle	39.4	37.6	40.7	41.1	41.7	41.6	41.9
Horses	2.0	2.3	2.4	2.5	2.5	2.5	2.4
Sheep	1.0	1.7	1.7	1.7	1.6	1.6	1.6
Swine	2.3	1.2	1.1	1.1	1.1	1.1	1.0
Goats	0.3	0.4	0.4	0.3	0.3	0.3	0.3
American Bison	0.1	0.4	0.4	0.3	0.3	0.3	0.3
Mules and Asses	+	0.1	0.1	0.1	0.1	0.1	0.1
Total	**164.2**	**168.9**	**171.3**	**168.9**	**166.7**	**165.5**	**164.3**

Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.05 MMT CO_2 Eq.

1990-2012 Inventory Report:

Table 6-3: CH_4 Emissions from Enteric Fermentation (Tg CO_2 Eq.)

Livestock Type	1990	2005	2008	2009	2010	2011	2012
Beef Cattle	100.0	105.8	107.5	106.3	105.4	103.1	100.6
Dairy Cattle	33.1	31.6	34.1	34.4	34.1	34.5	35.0
Swine	1.7	1.9	2.1	2.1	2.0	2.1	2.1
Horses	0.8	1.5	1.6	1.6	1.6	1.6	1.7
Sheep	1.9	1.0	1.0	1.0	0.9	0.9	0.9
Goats	0.3	0.3	0.3	0.3	0.3	0.3	0.3
American Bison	0.1	0.4	0.3	0.3	0.3	0.3	0.3
Mules and Asses	+	+	0.1	0.1	0.1	0.1	0.1
Total	**137.9**	**142.5**	**147.0**	**146.1**	**144.9**	**143.0**	**141.0**

Notes: Totals may not sum due to independent rounding.
+ Does not exceed 0.05 Tg CO_2 Eq.

Commenter: Jean Bogner
University of Illinois - Chicago

Comment: The purpose of this letter is to, first, document the deficiencies of the current IPCC (2006) FOD model for landfill methane generation, recovery, and emissions as currently applied to U.S. sites under the GHGRP HH- methodologies [Spokas et al., 2011, 2015; Bogner et al., 2010, 2014, 2016]. In general, IPCC (2006) relies on 40-year old science using a 1970's landfill gas generation model as well as a default 10% oxidation value based on a 20-year old study for oxidation at one U.S. site (Czepiel et al., 1996a,b). Importantly, neither IPCC (2006) nor the recent modifications for oxidation and emissions added to the GHGRP methodologies explicitly model the major climate drivers for emissions now known from literature.

Comment: In addition, these model applications lack comprehensive field-validation for emissions. See Appendix A for more detailed discussion.

Comment: A second purpose is to introduce an existing, freely-available [www.ars.usda.gov], fully-documented, user-friendly JAVA tool for landfill methane emissions inventory reporting. This model [CALMIM] was developed using established relationships for gaseous & heat transport, then independently field-validated.

Comment: Instead of relying on a landfill gas generation model, CALMIM explicitly models landfill methane emissions based on 1-dimensional gaseous, heat, and water transport in each cover material for a typical annual cycle of 365 days. The major drivers are: 1) the individual cover thicknesses and physical properties at a specific site; 2) the annual climate cycle for each cover as it affects soil moisture and temperature at various depths and, in turn, methane transport and oxidation rates; and 3) the physical effect of engineered gas recovery on soil gas concentration gradients.

Comment: A third purpose is to initiate discussion regarding the application of CALMIM as an alternative to IPCC (2006) for landfill methane emissions inventory reporting under the GHGRP. As stated in IPCC (2006), "higher order validated" models are permitted under IPCC national GHG inventory guidelines.

Comment: In general, very wide ranges for methane emissions and oxidation had been quantified, often not aligning with the 10% value and ranging from negligible to >100% (uptake of atmospheric methane).

Comment: It is reasonable to point out that, in the intervening years, the expected temporal variability of oxidation rates over an annual cycle in site-specific cover materials has often been overlooked. In short, oxidation is a variable, not a constant, for each specific cover material at a specific global location.

Comment: Regarding b), potential improvements to the underlying IPCC (2006) FOD gas generation model, there were many problems with trying to fit this conceptual model to a growing database of site-specific field measurements for emissions. Those problems included large mismatches between modeled & measured emissions, a primary dependency for FOD-modeled methane emissions on waste in place for the California inventory [Appendix A] irregardless of waste composition data & k values, and observational data from current California sites where measured gas recovery rates were robustly & linearly related to WIP only [Appendix A; Spokas et al., 2015]. Thus CALMIM was developed as a new "emissions-only" model as discussed in Appendix B.

Commenter: Karin Ritter
American Petroleum Institute (API)

Comment: In lieu of a formal expert review process of the Preliminary Draft of the national GHG Inventory (GHGI), as was customarily done in past years, EPA released several memos between December 2015 and February 20161 outlining revisions under considerations for estimating GHG emissions from the Distribution, Transmission & Storage, Gathering & Boosting and Petroleum & Natural Gas production segments of the Petroleum and Natural Gas Systems sector. API's comments on those memos are provided herein as an attachment starting on page 6.

Comment: While the last set of memos on Production and Gathering and Boosting were still under expert review, EPA released the Public Review Draft of the GHGI, already incorporating the revisions that were dubbed "under consideration" in EPA's memos, without providing industry the opportunity to comment on these proposed revisions, or for EPA to incorporate industry's expert comments, prior to releasing the Draft GHGI for public review. In addition, the released Public Review Draft does not provide specifics on the revised methodological changes for specific sources and lacks the normal methodological details usually provided in the applicable Annexes.

Comment: Based on information provided in the memo Inventory of U.S. Greenhouse Gas Emissions and Sinks: Revisions under Consideration for Natural Gas and Petroleum Production Emissions (February 2016, Table 4), API attempted to recreate the production sector emission data reported in Table 3-43 of EPA's Public Review Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks. The following table summarizes API's comparison of 2013 source level emissions published in the April 2015 GHGI and the 2013 emission estimates from Table 3-43 of the recent Public Review version of the GHGI.

Table 1. Comparison of 2013 Emission Estimates for Natural Gas Production (including Gathering and Boosting)

	As Shown in Final 2015 GHGI **2013 Net CH_4 Emissions, MMT CO2e**	*Reflects Application of EPA's New Methodology* **2013 Net CH_4 Emissions, MMT CO2e**
Pneumatic Controllers	13.5	26.0
Major Equipment Fugitives	8.6	9.7
Chemical Injection Pumps	1.5	3.7
Dehydrator Pumps/Vents	12.2	12.2
Compressor Starts	0.1	0.1
Large Gathering Compressor Station Fugitives	0.4	43.3
Gathering Pipeline Leaks	4.2	
Gas Engines	2.7	2.7
Condensate Tanks	7.8	7.8
Blowdowns	0.2	0.2
Upsets	0.1	0.1
Wellpad Fugitives/Venting	11.5	11.5
Offshore	3.8	3.8
Other Voluntary Reductions	-16.5	-16.0
Regulatory Reductions	-3.0	
TOTAL	**47.0**	**105.1**

As is shown in the table above, total emissions for Natural Gas Production operations are estimated to increase from 47 million metric tonnes (MMT) CO2e as published in last year's GHGI, to 105 MMT

CO_2e, which indicates more than a doubling of emissions. It appears that EPA intends to include approximately 16 MMT CO_2e in emission reductions from voluntary activities, although it is unclear to which sources these emission reductions will apply. It is also unclear if fugitive emissions from wells are included under "Wellpad Fugitive Venting" or under "Major Equipment Venting". API is concerned that these additional details are not available for review and comment ahead of the final GHGI that is scheduled to be published in April 2016.

Comment: For Petroleum and Natural Gas Systems, EPA provides "computed" emission values for calendar year 2013, using the proposed, revised methodologies from EPA's sector specific memos. Emissions for the years 1990-2012 are not back-cast or updated, and EPA does state in the Public Review draft that the 2013 emissions estimates are preliminary and subject to revision in the final GHGI. As a result, it looks like a large step-change in estimated emissions for 2013 resulting from EPA's methodological changes. The new methodology used by EPA, especially for the Petroleum and Natural Gas production segments of the industry, does not reflect a "real" increase in emissions but rather improved availability of some industry activity data as reported to the GHGRP. The improved industry activity information provided by larger facilities, which are above the GHGRP reporting threshold, is being used by EPA for scaling up to the nationwide inventory without recognizing that the smaller (non-reporting) facilities likely have very different activity characteristics and thus should not be included in the scaled up activity factors proposed by EPA.

Comment: The estimated Petroleum Systems emissions for 2013 indicate a 151% increase as compared to what was previously reported for 2013 and is driven by an assumed increase of 157% in Petroleum Production emissions. This assumed emissions increase from Petroleum Production is due to EPA's scaling up the count of pneumatic controllers and process fugitive components as reported through the GHGRP. This does not reflect the fact that smaller production sites, which are not subject to GHGRP reporting, have much smaller component counts per wellhead and many of them use little – if any – pneumatic controllers, particularly in petroleum systems . Most importantly, EPA did not revise the emission factors used for characterizing overall emissions from pneumatic controllers and fugitive sources, despite repeated comments from industry that these factors are outdated and overestimate emissions from properly functioning pneumatic controllers and typical process components.

Comment: For Natural Gas Systems, EPA estimates that 2013 emissions would increase 23% after applying EPA's new estimation methodology. The data for individual segments such as production, processing, transmission & storage and distribution show a respective emissions change of 136%, 0%, -47% and -64%. Again, the change of 136% in the production segment is due to extrapolation of pneumatic controllers and process fugitive component counts from the GHGRP to a nationwide basis, as well as using the same overestimation of component counts for smaller production sites that do not report to the GHGRP. The change in Natural Gas Production also includes a new and very large estimate for Gathering and Boosting compressor stations based on limited, short-duration, downwind measurements. API does not believe the data used to derive emissions for Gathering and Boosting stations are sufficient for determining national emissions from these operations due to the large uncertainty associated with the measurement method on which they are based.

Comment: For some activity data, larger equipment counts would be expected for the types of sites that are more likely to be reported in the GHGRP. However, applying data from GHGRP sites to the entire population of U.S. wells is inappropriate. For example, emergency shut-down devices (ESDs) may be counted as pneumatic controllers in the GHGRP but have very different emission characteristics (infrequently emitting) than the types of pneumatic controllers that are assumed in the GHGI.

Comment: EPA's approach appears inconsistent. First, EPA notes that Subpart W GHGRP data covers 32% of the active wellheads for 2013 and proposes to use this percentage to "scale" some emission sources to a national level. Simultaneously EPA states that the GHGRP Subpart W data covers the majority of national oil and natural gas production sources. Separately, EPA has also determined that Subpart W covers about 85% of the GHG emissions from the onshore oil and natural gas production sector as indicated in the Subpart W Technical Support Document.

Comment: Clearly, if Subpart W covers 85% of the GHG emissions from theoil and natural gas production sector, then there is no basis for changing the GHGI in a manner that estimates 90% higher overall GHG emissions (based on the recalculated 2013 inventory). This discrepancy of GHGRP Subpart W emissions coverage must be fully explored and explained prior to making the proposed changes to derive GHG emissions for this sector in the GHGI. Given that the GHGRP Subpart W reported GHG emissions are substantially less than in the estimated GHGI emissions for 2013, the resultant scaling of the GHGRP data to national GHG emissions should be less than the 15% of emissions EPA previously determined are not covered by GHGRP Subpart W.

Comment: API agrees that updated GHGI activity factors and emissions data are warranted and as such recommends that EPA form a multi-stakeholder working group comprised of industry, governmental, and environmental organizations active in GHG emissions measurements and estimation to evaluate recently published data that may be considered for updating the national GHGI prior to rushing to implement the proposed revisions that are based on invalid extrapolation of GHGRP data from large facilities to non-reporting smaller installations.

Comment: API recognizes that emerging data from recent field studies have raised concerns about measurements uncertainty, and recognizes the need for a thorough discussion of means of improving the methodology to ensure collection of robust measurement data. API proposes that a working group – as discussed above - be convened following the completion of the 2014 GHGI (April 2016) to provide a structured framework for consultation and review of GHGI updates. An early start (April 2016) and frequent meetings (every 1-2 months) would provide sufficient time to review and consolidate information in an informed process for updating the 2015 GHGI (that would be published in April 2017) and beyond.

Commenter: Giles Ragsdale

Comment: My 2 cents - Figure ES-15 (I look at this figure every year) - I think the majority of people forget that when comparing current greenhouse gas emissions to 1990, the population has risen steadily which drives demand for and emissions from most categories of greenhouse gases, e.g. electricity, transportation, etc. I think this figure tells a great story - emissions per capita are down to flat compared to 1990. I'd say EPA is doing good work that the general population does not recognize and some politicians chose to not recognize.

Commenter: Bridget Chadwick

Comment: Page 3-4:
Clarify the definition of energy as "the capacity for doing work as measured by the capability of doing work (potential energy) or the conversion of this capability to motion (kinetic energy)" [EIA Monthly Energy Review, MER] and identify the types of energy sources: fossil fuels, nuclear, and renewables. Emphasize that some fossil fuels are consumed for non-energy purposes (e.g. feedstock, reducing agents and non-energy products) but are inventoried separately in Section 3-2.

Comment: Page 3-7, Figure 3-4 U.S. Energy Consumption (Quadrillion Btu):
change the scale of the graph to provide more detail; (2) add gridlines so that energy consumption can be read more easily from the graph; (3) It appears that data for energy consumption + consumption of fossil fuels for non-energy use have been graphed with a peak of about 100 qBtu in 2007. From my estimates, using fossil fuel energy data provided in Table A-18 of EPA's draft Inventory and nuclear and renewable energy provided in the EIA's MER, total energy consumption in 2007 peaked at about 93.5 qBtu.

Comment: Pages ES-19, 3-6, 3-7 "In the United States, 82 percent of the energy consumed in 2014 was produced through the combustion of fossil fuels..." (page 3-6). :
From my estimates, in 2014, total fossil fuel energy amounted to 73.6794 qBtu (using data in Table A-11 of the EPA's Inventory). Nuclear and renewable energy (including geothermal energy) and imported electricity amounted to 18.143 qBtu (using data in EIA's February 2016 MER Tables 1.3 and 2.6). So fossil fuel energy was about 80% of total energy consumed in 2014. My calculation of energy consumption for specific energy sources will differ from EPA's calculation, too.

Comment: Page 2-11, Figure 2-5: 2014 Energy Chapter Greenhouse Gas Sources (MMT CO2 Eq.):
The scale of the bar chart deemphasizes the significance of fossil fuel combustion. The scale should be expanded so that readers can see fossil fuel combustion produces the greatest portion (about 92%) of energy-chapter emissions. Furthermore, the adjacent piechart should show the breakdown of fossil fuel combustion in the energy chapter "slice".

Comment: Page 2-3, "Energy-related CO2 emissions also depend on the type of fuel or energy consumed and its carbon (C) intensity. Producing a unit of heat or electricity using natural gas instead of coal, for example, can reduce the CO2 emissions because of the lower C content of natural gas". :
(1) Explain that the carbon intensity of an energy mix (e.g. electricity) is the energy-weighted average of the CO2 emission factors of the energy sources in the mix; (2) Provide a table of CO2 emission factors for all energy sources including nuclear and renewable energy and/or refer readers to Table A-39.

Comment: Page 3-14, (a) "Recently an increase in the carbon intensity of fuels consumed to generate electricity has occurred due to an increase in coal consumption, and decreased natural gas consumption and other generation sources". (b) "Total U.S. electricity generators used natural gas for approximately 27 percent of their total energy requirements in 2014 (EIA 14" 2015b)". :
Please correct the above statements: (a) Using the EPA Inventory for fossil fuel data (Table A-11) and the EIA MER (Table 2.6) for C-free/neutral energy data, the c-intensity of electricity has DECREASED steadily since 2005, from 60.579 MtCO2/qBtu in 2005 to 52.785 MtCO2/qBtu in 2014. (b) In 2014, natural gas was 22% of the total primary energy consumed for generating electricity and C-free/neutral energy was 35% of the total primary energy.

Supplemental Material Received

Appendix A

Appendix A from the University of Illinois at Chicago comment on the U.S. Greenhouse Gas Emissions and Sinks: 1990-2014

Appendix B

Appendix B from the University of Illinois at Chicago comment on the U.S. Greenhouse Gas Emissions and Sinks: 1990-2014

Appendix C

Appendix API comments on EPA's Memos on the updates being considered for the Transmission and Storage, the Production and the Gathering and Boosting segments of the Petroleum and Natural Gas Systems Sector in the GHG Inventory from the American Petroleum Institute comment on the U.S. Greenhouse Gas Emissions and Sinks: 1990-2014

Appendix D

Appendix API Comments on Updates under Consideration for Natural Gas and Petroleum Production Emissions, and Gathering and Boosting Emissions from the American Petroleum Institute comment on the U.S. Greenhouse Gas Emissions and Sinks: 1990-2014

Appendix A

APPENDIX A.
Shortcomings of current IPCC (2006) methodology for landfill methane emissions.

To summarize the shortcomings of the current IPCC (2006) model, below are listed the major deficiencies with supporting references and datasets:

- This model was never systematically field-validated for CH_4 emissions. Rather, the historic "validation" consisted of comparing *measured recovery* to *modeled generation* at 9 Dutch landfill sites (Oonk & Boom, 1995; Van Zanten and Scheepers, 1995; Oonk, 2010)

- Model results do not systematically replicate results from a growing database of field measurements for CH_4 emissions (Spokas et al., 2011, 2015; Bogner et al., 2010, 2011, 2016).

- GHG inventories [e.g., California GHG inventory] often do not consider actual landfill gas recovery data at specific sites, only an assigned "recovery efficiency" percentage applied to modeled generation. Typically, the assigned landfill gas recovery can differ substantially in both magnitude and direction (+ or -) from measured recovery. (Bogner et al., 2010, 2016)

- Actual measured landfill gas recovery can be directly related related to waste in place (WIP) using a simple linear relationship. Fig. 1 below demonstrates this relationship for 129 California sites using data from Walker et al., (2012). The relationship shown in this figure was independent of climate, status (open or closed), age, or size (WIP).

  Historical Note: In general, landfill gas modeling began in California during the mid-1970's at the time of the first commercial landfill gas utilization projects. Then, At that time, a multiplicity of site-specific models were applied to the early project sites in order to predict future LFG recovery from waste-in-place (WIP), climate, waste composition, and other factors. [See further discussion in Findakakis and Leckie, 1979; EMCON, 1980; Halvadakis et al., 1983; Findakakis et al., 1988.] In those days, the choice of a particular model format for a specific site depended on optimizing the match between *predicted* annual LFG recovery and *actual* LFG recovery from the monitoring data available at that time. The models ranged from simple empirical relationships to complex, multicomponent multiphase kinetic models, some with lag times prior to the initiation of LFG generation. For the kinetic models, there was no unique solution for a specific site as multiple parameters were adjusted to improve model fit. The kinetic models (IPCC, 2006; LandGEM) were primarily adapted from the anaerobic digestion literature and accelerated laboratory decomposition studies on the premise that, conceptually, the annual mass of waste buried in a landfill may degrade similarly to waste in a digester but over longer timeframes.

  What might be a better idealized model for landfill biodegradation? Landfills also have significantly lower liquid contents than even "dry" or high solids digestion systems and, indeed, would be impossible to manage if digester values were applied to field settings. Taking a broader view, a better analogy for landfills is comparison to terrestrially-derived organic matter buried at shallow depths over

longer-term “geologic” timescales. Initially, after burial, some portion of the organic carbon undergoes anaerobic decomposition with biogas generation. However, a significant portion of the organic carbon in the buried waste does not degrade over decadal timeframes (Bogner, 1992; Barlaz, 1998) and is available for future transformations via deeper geologic burial under conditions of increased heat and pressure. That process is termed “diagenesis” with endpoints over geologic timescales expected to be similar to peaty/humic coal materials.

- In spite of variable waste input data and climate-related k values for LFG generation using IPCC (2006), the primary dependency for emissions is on waste-in-place (WIP). This can be demonstrated [Fig. 2 below] using the 2011 California GHG inventory data (372 full-scale landfill sites). [See also Spokas et al., 2015; Bogner et al. 2016.] Using this methodology, larger landfills [having high WIP] cannot reduce emissions below a certain threshold as defined by this relationship. Moreover, this relationship tends to reward larger sites with non-optimized gas recovery strategies [due to the relatively constant relationship for emissions to WIP]. Conversely, this relationship tends to reduce incentives for sites to improve gas recovery systems to achieve emission reductions as those reductions are not credited.

- As discussed above, the default assumption of 10% annual oxidation in IPCC (2006) is based on a single study at one landfill (Czepiel et al., 1996). *Oxidation is a variable*, not a constant, with unique seasonal trends in each cover soil at each site. [See discussion and data in Spokas et al., 2011; Spokas and Bogner, 2011; Bogner et al., 2011.]

- The 3 major drivers for emissions are excluded. These are:
  1) The area, composition, and thickness of *site-specific cover soils* as the major engineered barrier for emissions.
  2) Climate trends unique to both the specific global location (e.g, latitude/longitude) & individual cover soils with seasonally variable gaseous transport & CH_4 oxidation rates due to temporally and spatially variable soil moisture & temperature.
  3) The physical effect of the engineered LFG system to recover CH_4 and concurrently reduce soil gas CH_4 concentrations at the base of the cover, reducing the CH_4 concentration gradient and thus reducing diffusive flux [see Spokas et al., 2011].

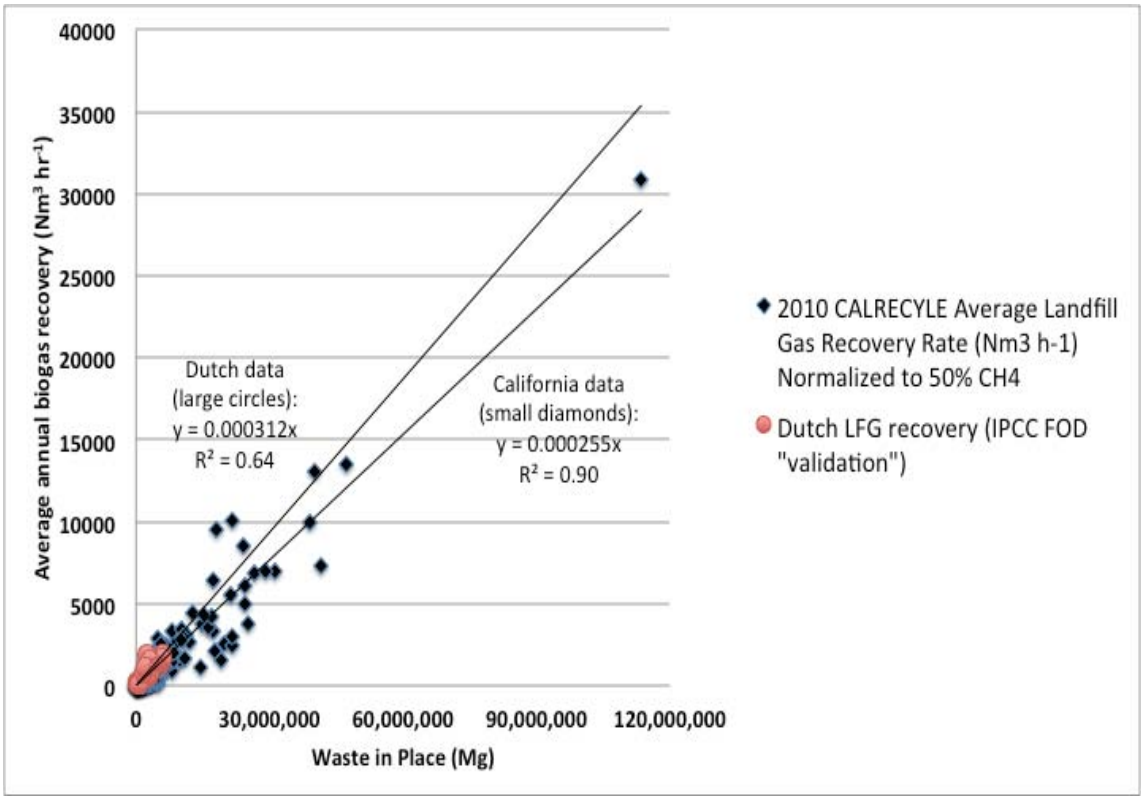


Fig. 1. Comparison between WIP and average biogas recovery rate for: *(a)* 2010 data from Calrecycles for 129 California sites (Walker et al., 2012): *blue diamonds*; and (b) IPCC FOD model field validation data from 9 Dutch landfills (1986-1993) (Oonk & Boom, 1995): *red circles.* Figure reprinted from Bogner et al., 2016.

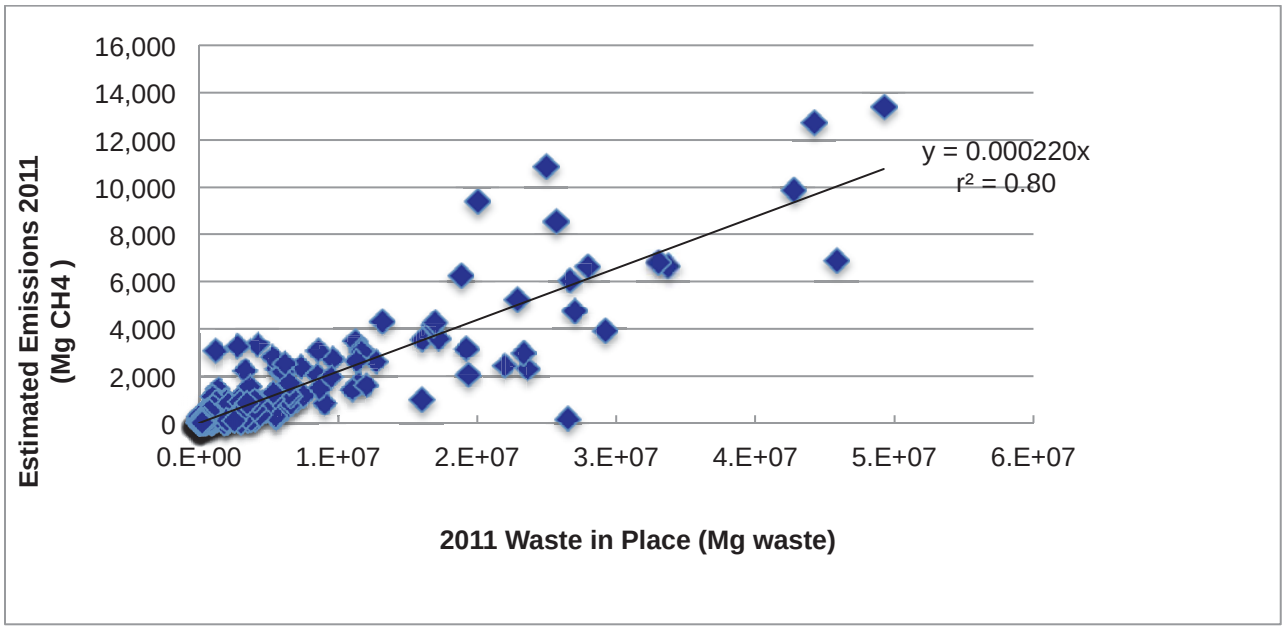
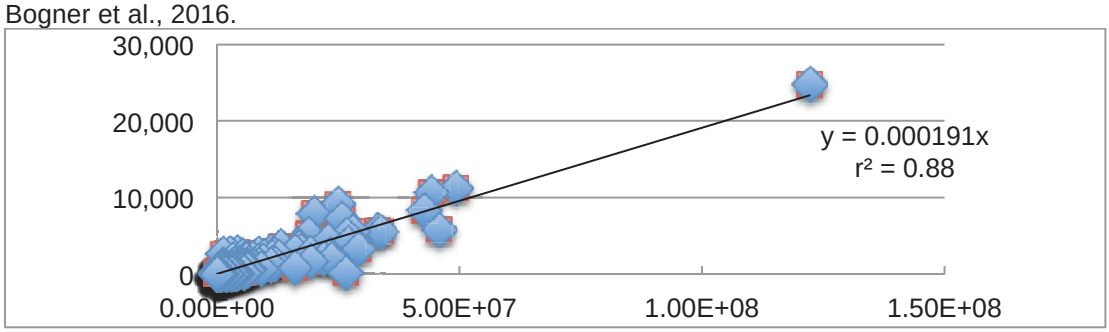


Fig. 2. (a) *ABOVE*: Relationship between estimated 2011 site-specific landfill CH_4 emissions using IPCC (2006) and WIP for 371 California landfills. (b) *BELOW*: Same relationship including the large Puente Hills Landfill [N=372]. Data from California Air Resources Board [ARB] (Hunsaker, 2012). NOTE: Predicted emissions from WIP using regression coefficients are 190-220 Mg CH_4/million Mg WIP. Figure reprinted from Bogner et al., 2016.



Appendix B

Appendix B.
Description and Overview of the CALMIM 5.4 Model.
[See Spokas et al., 2015; Bogner et al., 2014; Spokas et al., 2011; Spokas and Bogner, 2011; Bogner et al., 2011]

Developed over the last decade, CALMIM, or **CA**lifornia **L**andfill **M**ethane **I**nventory **M**odel, is a 1-dimensional finite difference model for the simultaneous simulation of heat, water, and gaseous transport through landfill cover soils. The model consists of a process-based methane *emissions* model which simulates emissions using 10-min time-steps and 2.5 cm depth increments in user-specified landfill cover materials at any global location. Table 1 at the end of this appendix provides an overview of the model structure, components and default boundary conditions. CALMIM is a freely available [www.ars.usda.gov] JAVA program which integrates site-specific data (location and cover design) with climatic simulation and one-dimensional soil microclimate and gas diffusion models for daily, intermediate, and final cover areas inclusive of CH_4 oxidation over a typical annual cycle. The model has proven to be user-friendly at sites where it has been applied to date (e.g., Cambaliza et al., 2015).

CALMIM includes: (1) the effect of engineered gas extraction; (2) the physical effect of daily, intermediate, and final cover materials to retard emissions; and (3) seasonal moisture and temperature effects on both gaseous transport and methanotrophic CH_4 oxidation in cover soils. The empirical relationship for oxidation used in the CALMIM model is derived from a series of over 900 laboratory incubations of landfill cover soils to determine relationships between methanotrophic activity and soil temperature & moisture (See Spokas and Bogner, 2011).

CALMIM was independently field-validated, first for v. 4.3 for California in the initial CALMIM project for the California Energy Commission [Bogner et al., 2011]. The original field validation for the CEC project (>800 measurements using static chambers) was conducted over two years on daily, intermediate, and final covers at two California sites, including the northern coastal Marina Landfill (Monterey County, CA) and the southern Scholl Canyon Landfill (Los Angeles County, CA). Also included were continuous measurements of soil temperature, moisture, and selected meteorological variables. Additional limited field validation was conducted for intermediate covers at the Lancaster, Kirby Canyon, and Tri-Cities Landfills through the cooperation of Waste Management, Inc. Oxidation was quantified through the use of a stable carbon isotopic method developed by J. Chanton which relies on the preference of CH_4–oxidizing microorganisms for the isotope of smaller mass (^{12}C) versus the heavier isotope (^{13}C). Subsequently, the improved CALMIM 5.4 developed under the EREF project was globally field-validated using 40 covers at 29 sites on 6 continents [Bogner et al., 2014], using data supplied directly by international research groups, published data, and data collected by the CALMIM team. A wide variety of methods (chamber, gradient, tracer, micrometeorological, vertical radial plume mapping, aircraft-based) were applied over scales ranging from <1m to km. CALMIM comparisons to field measurements resulted in a d-index of 0.765 using site-specific data (Willmott Index of Agreement; Wilmott, 1981), a Pearson r value > $|0.8|$ for modeled vs. measured comparisons at 25 of 29 sites, and an average mean error across all covers of 12 g CH_4 m^{-2} d^{-1}. Figure 3 below shows the main CALMIM input screen.

Figure 3. Main CALMIM input screen.

CALMIM estimates typical annual, site-specific landfill CH_4 emissions based on the respective areas and properties of daily, intermediate, and final cover materials, as well as the extent of engineered gas extraction. A major change from the IPCC (2006) method is that emissions are decoupled from a CH_4 generation model; instead, the emission processes at the top of the landfill are modeled directly. Another major change is that seasonal CH_4 oxidation is also modeled directly rather than relying on a % oxidation "default." In terms of the IPCC structure, CALMIM is an IPCC "validated, higher quality" methodology for typical annual CH_4 emissions from landfills. CALMIM consists of four major integrated components:

(1) Data-Input Template;
(2) Meteorological Model;
(3) Soil Microclimate Model;
(4) 1-D Emissions/Oxidation Model.

With regard to (1), site locations are linked to latitude and longitude information. Input data are required on the surface area, thickness, and properties of the various cover materials for a particular site. Also, the extent of gas extraction and seasonal vegetation for each cover type are also required (both as % of surface area). With regard to (2) and (3), the meteorological and soil microclimate models rely on modified versions of the following globally-validated USDA models: Global TempSIM, Global RainSIM, Solarcalc, and STM^2. In particular, the soil temperature functions for STM^2 (Soil Temperature and Moisture^2) were modified to accommodate the landfill heat source. The latitude and longitude of the site are used to extrapolate the daily climatic conditions, as well as the soil microclimate conditions for 10-min. intervals for (minimum) 2.5-cm. depth increments for any landfill cover soil. With regard to (4), the emissions model is based on 1-dimensional diffusional transport of CH_4 and O_2 through each specified cover material.

The driving force is the CH_4 concentration gradient through the cover materials, which is dependent on the presence or absence of engineered gas recovery, the thickness and properties of the cover materials, and seasonal CH_4 oxidation rates. Methane oxidation is modeled through the use of scaled results relative to maximum rates for the full range of soil temperature and moisture conditions based on extensive laboratory studies for California landfill cover soils (>2000 incubations) and published literature. Oxidation is quantified by the difference in separate CALMIM model runs with and without oxidation for each cover type. CALMIM also calculates total annual site emissions by summing the emissions for all cover types. A standard substraction is also applied for O_2 uptake by heterotrophic respiration [competition for O_2 with CH_4 oxidation].

Below is shown (Fig. 4) some typical CALMIM output comparing 30 cm to 90 cm loamy sand intermediate covers at a southern California site. Note both the large variability in emissions at this site between the two thicknesses and differences for each thickness between the oxidized and unoxidized emissions. The highest emissions were associated with the mid-year dry season, diminishing in the later part of the year when the rainy season begins.

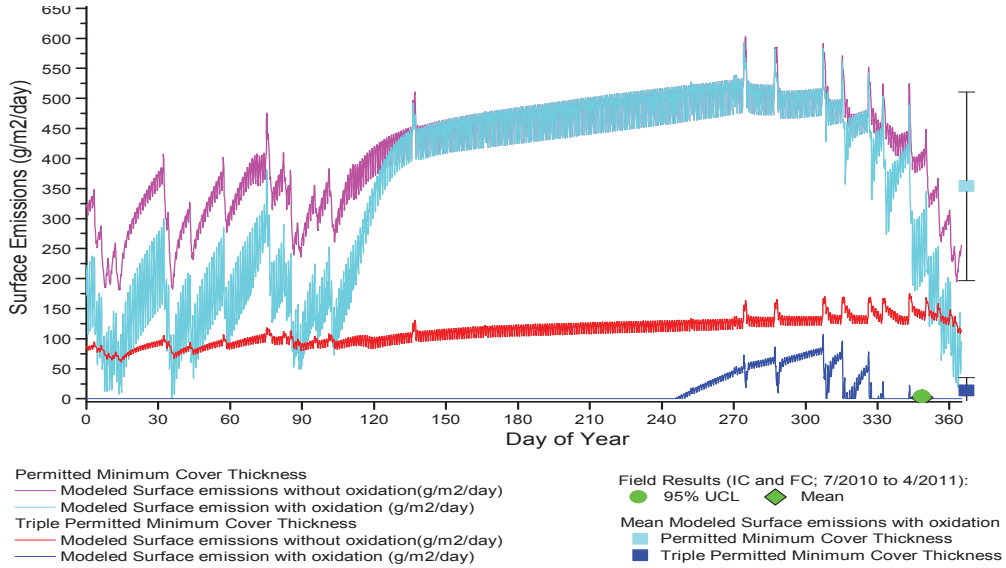


Fig. 4. Typical CALMIM output for southern California intermediate cover material. Comparison of 30 cm to 90 cm thickness over typical annual cycle. See text for additional explanation.

CALMIM relies on well-researched and accepted theoretical relationships, previous field and laboratory studies, existing globally-validated U.S. Dept. of Agriculture models, and extensive supporting laboratory studies on CH_4 oxidation using a variety of landfill cover soils over the full range of temperature and moisture conditions. Because the CALMIM model uses average climatic and soil microclimate data to calculate typical annual emissions, results may not be representative for atypical climate conditions (e.g., drought years) or where there are large differences in relief relative to regional weather stations. The site-specific application of CALMIM can be significantly improved through the use of

"advanced" functions and site-specific data, including field measurement of the CH_4 concentration at the base of the cover.

To demonstrate the strong climate dependency of emissions, we remodeled the 2010 California landfill CH_4 emissions inventory for 372 sites using Calrecycles data from Walker (2012) and the field-validated CALMIM5.4 model (Spokas et al., 2015, Spokas et al., 2011), then compared the results to the existing 2010 California inventory from the California Air Resources Board (ARB) using the IPCC (2006) FOD model with regional California waste data and k values. See Fig. 5 below. It is important to note that the ARB method applies a 75% gas recovery efficiency to estimate the residual emissions, regardless of actual gas recovery. Importantly, the IPCC methodology does not consider either soil or climate drivers for gaseous transport nor seasonal methanotrophy in cover soils, allowing only the 10% annual oxidation per Czepiel et al. (1996 a,b).

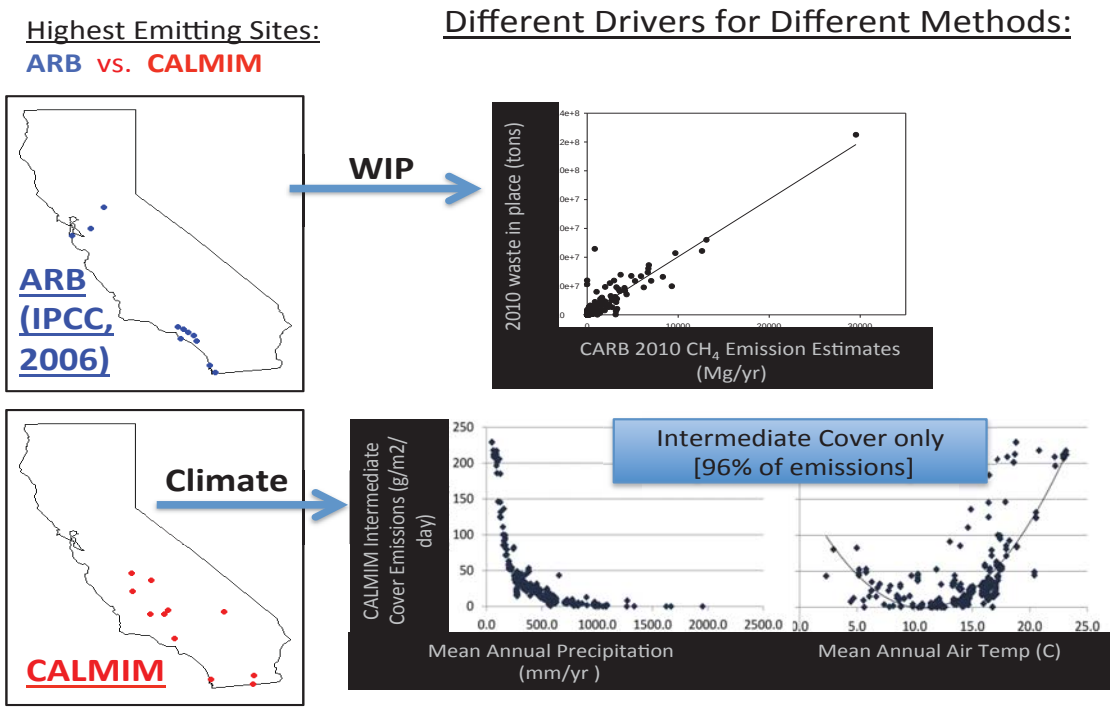


Fig. 5. Comparison of major dependencies for estimated California landfill CH_4 emissions using:
TOP: 2010 ARB inventory based on IPCC (2006) model showing dependency on WIP. BOTTOM: 2010 inventory using CALMIM 5.4 showing dependency on climate for intermediate cover [96% of estimated state emissions]. Cover areas from Walker et al., (2012). The typical intermediate cover was modeled as 90 cm loamy sand with emission rates normalized to g CH_4 m^{-2} d^{-1}. See Spokas et al. (2015) for additional discussion and details. Also shown at left are the 11 highest emitting sites from each inventory.

Note that, in Fig. 5 the intermediate cover emissions for a typical 90 cm loamy sand are <20 g CH_4 m^{-2} d^{-1} when the mean annual precipitation (MAP) is >500 mm y^{-1}. Moreover, comparing the highest-emitting sites between the ARB and CALMIM inventories, those

sites shift from landfills containing the largest mass of waste in the ARB inventory to sites with large areas of thinner intermediate cover and reduced oxidation rates during the annual cycle (e.g., too hot, too dry). These climate dependencies have important implications for developing more realistic, science-based GHG inventories for landfill CH_4.

Finally, we also directly compared CALMIM modeling using site-specific inputs for cover materials and areas to field measurements at 10 California sites [Fig. 6]. Field methods ranged from meter to kilometer scales, including chamber techniques, vertical radial plume mapping (VRPM), and aircraft plume methods. In this figure, we show standard CALMIM outputs for CH_4 emissions with oxidation and CH_4 emissions without oxidation for a "typical annual cycle" of 365 days. The plots shown in this figure include both single cover materials and whole site measurements over several years, depending on the methodology, scale, and date of the individual campaigns cited in the figure caption. See Spokas et al. (2015), Bogner et al. (2014), and references cited therein for additional details.

In Fig. 6., please also note the high seasonal variability and the large seasonal differences between the upper blue lines (emissions without oxidation) and the lower black lines (emissions with oxidation). Especially note that the lines for emissions with and without oxidation become merged at several sites during the mid- to late-year dry season due to negligible oxidation (too hot, too dry). Thus, modeled emissions inclusive of oxidation readily respond to dynamic soil moisture and temperature effects on oxidation rates during an annual cycle. Moreover, when examining results from any short-term field measurement campaigns at a specific global location, it is important to consider those results within the larger expected temporal variability of emissions over an annual cycle. In short, consistent with other soil sources of CH_4, climate effects on both oxidation and gaseous transport can vary greatly between cover soils at any one site, as well as seasonally and spatially between sites (Cambaliza et al., 2015).

In general, the CALMIM modeled emissions align with the field values and, as a minimum, are within the same order of magnitude. Differences can be attributed mainly to: (1) cover thickness and/or composition not modeled correctly (may not be rigorously tracked at specific sites except to confirm "permitted minimum" thickness or materials); (2) whether daily cover area emissions were realistically modeled (i.e., whether the working area overlies new waste only with expected low fluxes or fully methanogenic older waste driving high fluxes, with or without gas recovery); and (3) annual weather variability compared to 30-year average weather with 0.5 degree reliability.

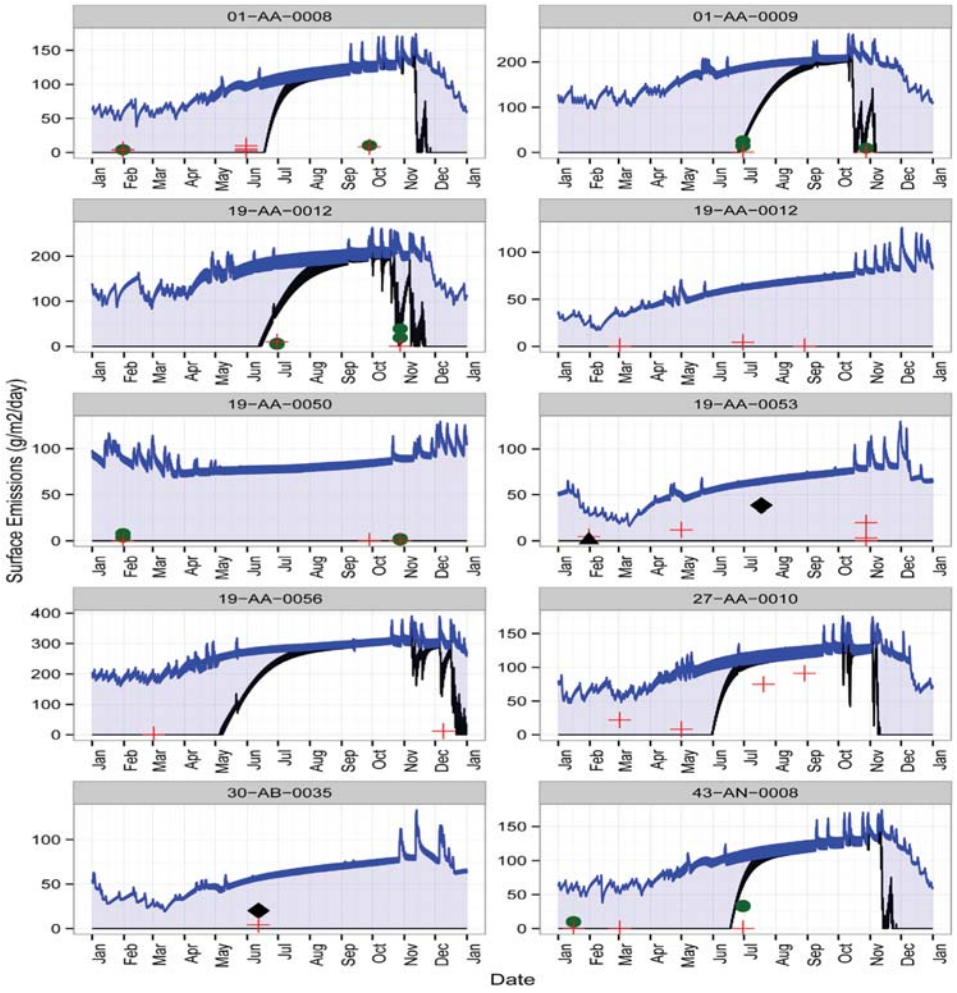


Figure 6. TOP: Comparison of typical annual cycle of emissions using CALMIM at 10 California sites to field measurements using a variety of techniques. CALMIM results indicate the "typical annual cycle" of 365 days where the black line is predicted emissions with soil oxidation and the blue line represents surface emissions without oxidation. The region between is shaded in light blue. Field results are plotted for the month of the measurement using different symbols for different techniques: Red plus sign indicates surface chambers (Spokas et al, 2011; Shan et al, 2012), black diamond/triangles indicates aircraft plume measurements (Peischl et al, 2013; Tratt et al, 2014), and the green circle indicates vertical radial plume mapping [VRPM] methods (Goldsmith et al, 2012). All units are g CH_4 m^{-2} d^{-1}. Figure reproduced from Spokas et al., 2015; please consult for further details. BOTTOM: Location map for California sites.

CALMIM is written entirely in JAVA and currently consists of 531 Java Classes and is written in the NetBeans Integrated Developer Environment (IDE). NetBeans IDE and NetBeans Platform are based on software from netbeans.org, which has been dual licensed under the Common Development and Distribution License (CDDL) and the GNU General Public License Version 2 with Classpath exception. For more information, please visit www.netbeans.org.

CALMIM uses a total of 21 integrated libraries, with the most significant ones being:

- **jFreeChart** – Provides the graphical display of the generated data - see http://www.jfree.org/
- **Liquid-Look-n-Fee**l – Overall look-n-feel of the program
- **PTPLOT 5.6** – plotting program to display data - http://ptolemy.eecs.berkeley.edu/java/ptplot/
- **NanoXML** – Embedded XML parser for the CMM preference files http://nanoxml.sourceforge.net/orig/
- **XStream** – simple library to aid in saving and loading XML class library files (CMM preference file) - http://xstream.codehaus.org/
- **MigLayout** – layout manager for GUI windows http://miglayout.com/

As stated above, CALMIM is a 1-dimensional finite difference model for the simultaneous simulation of heat, water, and gas transport through the landfill soil cover. Table 1 below provides an overview of the model structure, components and default boundary conditions:

Table 1. Overview of CALMIM input parameters, bundled models, and outputs.

				Description		**Value/Units/Reference**
Model Inputs	Site			Latitude		Decimal degrees (+N , -S)
				Longitude		Decimal degrees (-W, +E)
				Waste Footprint		Acres
	Cover Characteristics			Coverage		0-100% of waste footprint
				Organic Matter		Low-high (0-5%)
				Vegetation Presence		0-100% cover (slider bar) Modifies incoming solar radiation [Si = (1-Veg%)*Si]
				Gas Recovery System		0-100% coverage (slider bar) Reduces the lower methane concentration in default cover scenarios
		Cover Type Selection				
			Daily	Temperature	Upper	Air temperature simulation
					Lower	25 °C
				CH_4	Upper	2 ppmv
					Lower	0.3 % (v/v)
				Oxygen	Upper	20 % (v/v)
					Lower	5 % (v/v)
				CH_4 oxidation rate		400 µg CH_4 $g_{soil}^{-1}d^{-1}$
			Intermediate	Temperature	Upper	Air temperature simulation
					Lower	35 °C

		CH_4	Upper	2 ppmv
			Lower	45 % (v/v)
		Oxygen	Upper	20 % (v/v)
			Lower	1 % (v/v)
		CH_4 oxidation rate		400 µg CH_4 $g_{soil}^{-1}d^{-1}$
		Temperature	Upper	Air temperature simulation
			Lower	40 °C
	Final	CH_4	Upper	2 ppmv
			Lower	55 % (v/v)
		Oxygen	Upper	20 % (v/v)
			Lower	0 % (v/v)
		CH_4 oxidation rate		400 µg CH_4 $g_{soil}^{-1}d^{-1}$
	Custom	User selectable boundary conditions		
Layer Characteristics		Material		Various materials (Table 2)
		Thickness		Variable: 2.5 cm to 2.5 m (1 to 100”)

Table 1. (Continued)

				Description	Value/Units/Reference
Bundled Models	GlobalTempSIM			Air temperature simulation	Spokas and Forcella, 2009
	GlobalRainSIM			Precipitation simulation	Spokas and Forcella, 2009
	SolarCalc			Solar radiation simulation	Spokas and Forcella, 2006
	STM^2			Soil temperature and moisture model	Spokas and Forcella, 2009
	Gas Diffusion			Oxygen and methane diffusion	Campbell, 1985
Model Outputs	*Model outputs are written directly to Excel compatible files for each cover type*				
	Daily Surface CH_4 emissions		With oxidation		g CH_4 $m^{-2}d^{-1}$
			Without oxidation		g CH_4 $m^{-2}d^{-1}$
	Soil Nodes (2.5 cm layer in cover)		Soil Temperature		^oC
			Soil Moisture		Volumetric (cm^3 cm^{-3})
			Air-filled porosity		cm^3 cm^{-3}
			Oxygen Concentration		% O_2
		CH_4 Concentration		With oxidation	% CH_4
				Without oxidation	% CH_4
			CH_4 oxidation rate		g CH_4 $m^{-2}d^{-1}$
			CH_4 oxidation percentage		%
			Bulk density		g cm^{-3}
			Fraction of time oxidizing		0 to 100% (0-1)
	Simulated Weather Data		Maximum air temperature		^{o}C
			Minimum air temperature		^{o}C
			Precipitation		mm

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Appendix C

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Re: Updates under Consideration for Natural Gas Transmission and Storage Segment Emissions in the 1990-2014 GHG Inventory

Dear Melissa,

The American Petroleum Institute (API) appreciates the opportunity to provide comments on proposed updates to the 1990-2014 U.S. Greenhouse Gas (GHG) inventory for the Natural Gas Transmission and Storage segment.

API continues to compile and analyze emissions data for petroleum and natural gas operations and is open to working with EPA on utilizing data provided through EPA's mandatory GHG reporting program (GHGRP). API has provided comments and recommendations to the U.S. EPA on the draft Natural Gas Systems and Petroleum Systems sections of the national inventory since 2002, including at the recent stakeholder workshop in November 2015 regarding GHG data for Petroleum and Natural Gas Systems.

For this current review, API provides general comments and also addresses several specific questions raised in EPA's transmission and storage memo. Our review, however, is limited due to the short response time, overlapping comment periods for other proposed changes to the GHGRP, and the approaching March deadline for reporting 2015 GHGRP data.

General Comments

EPA's proposed updates for compressor station components rely primarily on two studies published by Colorado State University in 2015[1] [2]. Substantial new data are available from measurements at

[1] Subramanian, R.; Williams, L.L.; Vaughn, T.L.; Zimmerle, D.; Roscioli, J.R.; Herndon, S.C.; Yacovitch, T.I.; Floerchinger, C.; Tkacik, D.S.; Mitchell, A.L.; Sullivan, M.R.; Dallmann, T.R; Robinson, A.L. Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol. Environmental Science and Technology, 49, 3252-3261. 2015.

transmission and storage compressor stations that report through Subpart W. API agrees that updated GHGI emissions data are warranted and as such recommends that EPA form a multi-stakeholder working group comprised of industry, governmental, and environmental organizations active in GHG emissions measurements and estimates to evaluate recently published data that may be used for updating the national GHG inventory. API proposes that such a working group be convened following the completion of the 2014 GHGI to provide a structured framework for consultation and review of GHGI updates. An early start (April 2016) and frequent meetings (every 1-2 months) would provide sufficient time to review and consolidate information in an informed process for updating the 2015 GHGI and beyond.

API reiterates that the EPA should carefully analyze and screen GHGRP reported data in order to improve the validity of data used in the national GHGI. Obvious data errors and/or outliers should be assessed, corrected or excluded to prevent disproportionately impacting the derivation of emission factors (EFs) or extrapolation of information for the national GHGI.

Responses to EPA Questions

Transmission and Storage Station Fugitive Emissions

- ✓ (Question #1 from EPA's memo) As EPA considers options for applying EFs for this source, the EPA seeks stakeholder feedback on the timing of changes in transmission and storage stations non-compressor fugitive sources that may result in different emissions in recent years from those in the GRI/EPA study. The EPA could use GRI/EPA factors for earlier years in the time series, and Zimmerle factors for more recent years. Alternatively, the EPA could apply the Zimmerle EF to all years of the GHGI time series. The EPA seeks stakeholder feedback on these options.

  API Comment: GRI/EPA emission factors should be used for initial estimates in the time series and EPA should use updated emission factors for the current estimate.

- ✓ (Question #3 from EPA's memo) The EPA seeks stakeholder feedback on how to incorporate information on super emitters into estimates for transmission and storage stations. For example, the Zimmerle study estimated a fraction of the population that may be super emitters at a given time, and estimated super emitter emissions from these sources (incremental to those estimated for the non-super emitter population). The EPA also seeks stakeholder feedback on which GHGI sources are more likely than others to act as super emitters and whether and how to apply a super emitter factor or other methodology to those sources.

  API Comment: Recent measurement studies have shown skewed "long tail" distributions for source level measurements, where a few emission sources may contribute a disproportionately high fraction of emissions. As the Zimmerle study points out, large data sets are needed to accurately characterize the "long tail" distributions. Although the Subramanian study contributes new measurement data for 45 compressor and storage stations, it represents just a

[2] Zimmerle, D.J.; Williams L.L.; Vaughn, T.L.; Quinn, C.; Subramanian, R.; Duggan, G.P.; Willson, B.; Opsomer, J.D.; Marchese, A.J.; Martinez D.M.; Robinson, A.L. Methane Emissions from the Natural Gas Transmission and Storage System in the United States. Environmental Science and Technology, 49, 9374-9383. 2015.

subset of all measurements conducted as part of Subpart W reporting, which provides a substantially larger data set of emissions that are characteristic of the entire distribution.

As the Zimmerle study indicates, the identified "super emitters" fraction of the population is dynamic and may vary each time a measurement is taken. Therefore the approach being proposed by EPA in the question – which implies that EPA is considering to separately adjust the national inventory for super-emitters – is not appropriate for extrapolation of the data to the national GHGI. This approach would be incorrect and would essentially double count the effect of super-emitters since they are already accounted for in the Zimmerle emission factors and in the Subpart W reported data.

The Pipeline Research Council International (PRCI) is conducting a research project to compile and analyze Subpart W data. The dataset includes 2011 through 2013 measurement data collected from members who have also provided supplemental data on equipment, operations, and measurement methods. Although a subset of data reported to EPA, it represents well over half of the reporting facilities. These measurement data should be assessed and can be used to calculate compressor station emission factors and evaluate the frequency and size of the larger leaks from key sources – compressor seals, compressor valves and storage tank dump valves. The report is expected to be available in the second quarter of 2016.

API advises that an alternative approach would be to develop new average emission factors that integrate data from both the recent measurement study results and Subpart W measurements. Such average emission factors should incorporate the range of emissions observed in current operations without artificially superimposing on them a "super emitter" adjustment which is highly uncertain. The emission factors should be updated periodically based on additional Subpart W data that become available with each future reporting year and potentially new, relevant and independent measurement programs.

- ✓ (Question #4 from EPA's memo) The EPA seeks stakeholder feedback on how to incorporate Subpart W data into the GHGI methodology, such that the transmission station and storage station activity data (AD) and/or EFs would be updated annually to reflect ongoing trends in the industry. For example, the EPA could consider combining the Zimmerle et al. data and Subpart W data in some way.

API Comment: A significant amount of information is reported to EPA through Subpart W. EPA now has four years of fugitive measurement data for specific emission sources and activity data regarding the distribution of centrifugal versus reciprocating compressors as well as the fraction of wet seal versus dry seal centrifugal compressors. API encourages EPA to make use of this information and integrate Subpart W based emission factors as an update to the GHGI. Activity data and emission factors should be updated periodically based on additional Subpart W data that become available with each future reporting year and potentially new, relevant, and independent measurement programs.

EPA's memo on revisions under consideration for transmission and storage emissions indicates that EPA intends to use the emission factors for compressor fugitive emissions, non-compressor fugitive emissions, and pneumatic controllers from the Zimmerle study. API supports the use of this recent measurement data, which accounts for the presence and random nature of super-emitters. However, API strongly encourages EPA to also make use of the substantial amount of

measurement data available from Subpart W. The PRCI report is an example of additional information that should be considered by EPA and a multi-stakeholder workgroup.

- ✓ (Question #5 from EPA's memo) In fall 2015, a well in a California storage field began leaking methane at an estimated rate of 50 Mt CH4 per day. The EPA is considering how to include this emission source in its 2017 GHGI (with estimates from 1990-2015). For example, the EPA could review and potentially incorporate estimates of the leak developed by the California Air Resources Board (CARB).

API Comment: The storage field leak in California is a one-off failure event. If EPA believes the emissions from this event warrant inclusion in the 2015 national GHG emissions for Natural Gas Systems, then API contends that the emissions should be estimated for this single event with an annotation in the inventory which references the event and the emission estimation method. The emissions from this singular event should not be back-cast to prior years, nor should the emissions be projected to future years.

Reciprocating and Centrifugal Compressors

For Storage, EPA is not considering changes to the method used to count compressors. EPA plans to report a combined number and will not differentiate between reciprocating and centrifugal compressors to be consistent with planned updates to the emission factor. EPA's memo notes that the Zimmerle study found most storage stations employ reciprocating compressors. However, this is inconsistent with the Subramanian study which observed that the compressor type can impact emissions and centrifugal compressors have become much more common at transmission and storage stations. For compressor emission factors applied to Storage, API recommends utilizing storage station compressor measurement data reported for Subpart W to develop emission factors separately for reciprocating and centrifugal compressors, and also report compressor emissions separately by compressor type. This provides greater transparency and enables trends in compressor counts and emissions to be tracked over time.

Pneumatic Controllers

- ✓ (Question #11 from EPA's memo) The EPA seeks stakeholder feedback on use of the Zimmerle et al. estimates of pneumatic controller counts per transmission or storage station to develop national AD across the time series. For example, the EPA could use GRI/EPA pneumatic controller counts for earlier years in the time series and Zimmerle et al. counts for more recent years. Alternatively, the EPA could apply the Zimmerle et al. pneumatic controller counts to all years of the GHGI time series. The EPA seeks stakeholder feedback on these options.

API Comment: Subpart W provides a comprehensive, annual data set for determining the number of pneumatic controllers by station and the distribution by type of controller. API recommends using the Subpart W activity data for recent years in the GHGI, the GRI/EPA data for early years in the time series, and interpolating between the two for intermediate inventory years rather than using activity data that is based on the Zimmerle or Subramanian study.

- ✓ (Question #13 from EPA's memo) The EPA seeks stakeholder feedback on approaches to stratify pneumatic controller estimates into specific bleed rate categories (e.g., basing AD on the number of low-bleed, intermittent bleed, and high bleed devices and applying an EF

specific to each type). For example, the EPA could use the Subpart W data on the number of pneumatic controllers of specific controller types per station, and their associated specific EFs. In addition, the EPA seeks comment on use of GHGRP data to represent national transmission and storage station pneumatic controller activity and emissions.

API Comment: API recognizes that the stratification of pneumatic controllers into specific bleed rate categories can be challenging. API has recently engaged in technical assessments of pneumatic controllers' categories and their leakage vs. engineered venting characteristics[3]. Over the past year, through API's standard development process including a stakeholders group, API has been working to establish a process for categorizing properly functioning pneumatic controllers and to address fugitive emissions from mal-functioning controllers. API hopes that this standard, when complete, will go a long way towards addressing the issue raised by EPA above.

Hi-Flow Sampler Measurements

- ✓ (Question #14 from EPA's memo) Much of the available measurement data on transmission and storage segment emissions were developed using Hi-Flow Samplers. A recent study, Howard 2015, highlights potential malfunctions in certain Hi-Flow instruments under certain conditions that can lead to underestimates. The EPA is seeking stakeholder feedback on the impacts of the Hi-Flow sampler issue on the results of studies highlighted here and whether are there methods for recalculating some of the data points to correct for it.

API Comment: The Subramanian study showed good agreement between the concurrent site level emission source measurements and down-wind tracer flux measurements. The study report indicates that the dominant uncertainty in the study onsite estimate is due to uncharacterized emission sources (undetected or identified as inaccessible) rather than "parametric uncertainty associated with individual measurements or instruments." Based on this observation by the researcher/author, it might be concluded that the issues identified by Howard did not appear to have occurred in the measurements conducted during the Subramanian study.

The June 2015 article by Howard (Energy Science and Engineering 2015; 3(5):443–455, doi: 10.1002/ese3.81) focusses on measurements conducted in the production sector ("UT Phase 1" Study) and has drawn attention to a sensor response issue that may be averted to a large extent with a firmware update, careful calibration, and repeated quality control checks during the measurement process. Allen responded to Howard's article, providing information that extra steps were undertaken during to ensure the validity of the measurements from the UT Phase 1 study.[4]

The Hi-Flow instrument is one of a very few existing devices for cost-effectively quantifying natural gas emissions from fugitive and venting at the emission source, and it is an approved measurement device under Subpart W. As with any measurement device, uncertainties in measured data exist and the experience gained by additional field studies is enabling the

[3] [Simpson, 2014] Pneumatic Controllers in Upstream Oil and Gas, *Oil & Gas Facilities Volume 3 Number 5*, October, 2014

[4] Allen, D.T., Sullivan, D.W., and Harrison, M. Response to Comment on "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers", Environmental Science & Technology, 49, 3983-3984, doi: 10.1021/acs.est.5b00941 (2015).

research community to alert instrument manufacturers and industry to operation and calibration problems that ought to be fixed.

API's comments above are based on our long term engagement in reviewing and providing information for the U.S. GHG Inventory. It includes observations and recommendations for careful QA/QC of data extracted from the mandatory GHGRP to improve the validity and representativeness of data used for the U.S. GHG Inventory. We reiterate our recommendation for EPA to form a multi-stakeholder workgroup to discuss updating the national GHGI to incorporate information from recent measurement study results and Subpart W data.

API appreciates the opportunity to provide comments on the proposed revisions to the U.S. national GHG Inventory and EPA's willingness to work with industry to improve the data used for the national inventory. API encourages EPA to continue these collaborative discussions and is available to work with EPA to make best use of the information available under the GHGRP to improve the national emission inventory. We look forward to continuing our collaborative work in the GHGI development process.

Sincerely,

Karin Ritter

cc: Alexis McKittrick, Climate Change Division

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March 2, 2016

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Re: Updates under Consideration for Natural Gas and Petroleum Production Sector Emissions and Gathering and Boosting Emission in the 1990-2014 GHG Inventory

Dear Melissa,

The American Petroleum Institute (API) appreciates the opportunity to provide comments on proposed updates to the 1990-2014 U.S. Greenhouse Gas Inventory (GHGI) for the Natural Gas and Petroleum Production Sectors, and for Gathering and Boosting emissions.

API continues to compile and analyze emissions data for petroleum and natural gas operations and appreciates the opportunity to work with EPA on utilizing data provided through EPA's mandatory greenhouse gas reporting program (GHGRP). API has provided comments and recommendations to the U.S. EPA on the draft Natural Gas Systems and Petroleum Systems sections of the national inventory since 2002, including at the recent stakeholder workshop in November 2015 regarding greenhouse gas (GHG) data for Petroleum and Natural Gas Systems.

For this current review, API provides general comments and also addresses several specific questions raised in the two EPA memos:

- Inventory of U.S. Greenhouse Gas Emissions and Sinks: Revisions under Consideration for Natural Gas and Petroleum Production Emissions, February 2016; and
- Inventory of U.S. Greenhouse Gas Emissions and Sinks: Revisions under Consideration for Gathering and Boosting Emissions, February 2016.

Our review, however, is as comprehensive as is possible within the short response time, overlapping comment periods for other proposed changes to the GHGRP and the approaching March deadline for reporting 2015 GHGRP data. On top of our response to these memos, API intends to also comment on the "public review" version of the 1990-2014 preliminary Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks that was released on February 22, 2016.

General Comments

- EPA's current methodological updates for ***natural gas and petroleum production*** operations rely primarily on Subpart W reported activity data with a focus on fugitive emission sources and pneumatic devices. Of note is that the production memo does not

address new measurement studies or updates that were previously outlined in two memos EPA issued in April 2015.[1,2]

- EPA's logic, presented in these memos appears inconsistent. First, EPA notes that Subpart W GHGRP data covers 32% of the active wellheads for 2013 and proposes to use this percentage to "scale" some emission sources to a national level. Simultaneously EPA states that the GHGRP Subpart W data covers the majority of national oil and natural gas production sources. Separately, EPA has also determined that Subpart W covers about 85% of the GHG emissions from the onshore oil and natural gas production sector - see the Subpart W Technical Support Document (Table 5, Threshold Analysis for Petroleum and Natural Gas industry Segment; https://www.epa.gov/sites/production/files/2015-05/documents/subpart-w_tsd.pdf). Clearly, if Subpart W covers 85% of the GHG emissions from this sector, then there is no basis for changing the GHGI in a manner that estimates 90% higher overall GHG emissions (based on the recalculated 2013 inventory). This discrepancy in GHGRP Subpart W emissions coverage must be fully explored and explained prior to making the proposed changes to derive GHG emissions in the GHGI for this sector. Given that the GHGRP Subpart W reported GHG emissions are substantially less than in the GHGI for 2013, the scaling to national GHG emissions for the GHGI should also be less than the 15% of emissions EPA previously determined are **not** covered by GHGRP Subpart W.

- EPA's methodological updates for ***Gathering and Boosting*** relies solely on data from the Mitchell et al.[3] and Marchese et al.[4] studies. However, the study focused on downwind, site-level ambient concentration measurements that are not appropriate nor designed to characterize activity data or emission factors for the Gathering and Boosting sector sources.

- API suggests that EPA review the work of Eben Thoma et al. with the EPA's Office of Research and Development (ORD) pertaining to off-site ambient concentration type studies, and the criteria necessary to obtain useful information from such a study as well as the limitations to the accuracy and usefulness of the information developed.[5] The conclusions are similar to the conclusions from an Australian government commissioned study conducted by CSIRO.[6] (For EPA's convenience, copies of both papers are provided in the appendix to these comments, beginning on page 20)

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[1] "Inventory of U.S. Greenhouse Gas Emissions and Sinks: Potential Revisions to Liquids Unloading Emissions Estimate" April 2015.
[2] "Inventory of U.S. Greenhouse Gas Emissions and Sinks: Potential Revisions to Pneumatic Controller Emissions Estimate (Production Segment)" April 2015.
[3] Mitchell, A. L.; Tkacik, D. S.; Roscioli, J. R.; Herndon, S. C.; Yacovitch, T. I.; Martinez, D. M.; Vaughn, T. L.; Williams, L.L.; Sullivan, M.R.; Floerchinger, C.; Omara, M.; Subramanian, R.; Zimmerle, D.; Marchese, A.J.; Robinson, A.L. Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Results. Environmental Science & Technology, 49, 3219−3227. 2015.
[4] Marchese, A. J.; Vaughn, T. L.; Zimmerle, D.J.; Martinez, D.M.; Williams, L. L.; Robinson, A. L.; Mitchell, A. L.; Subramanian, R.; Tkacik, D. S.; Roscioli, J. R.; Herndon, S. C. Methane Emissions from United States Natural Gas Gathering and Processing. Environmental Science & Technology, 49, 10718-10727. 2015.
[5] Halley L. Brantley,†,# Eben D. Thoma,*,† William C. Squier,† Birnur B. Guven,‡ and David Lyon§; Assessment of Methane Emissions from Oil and Gas Production Pads using Mobile Measurements
[6] Day, S., Dell'Amico, Fry, R., Javanmard Tousi, H., (2014). Field Measurements of Fugitive Emissions from Equipment and Well Casings in Australian Coal Seam Gas Production Facilities. CSIRO, Australia

- API is concerned about EPA's intent to utilize the Mitchell et al. and Marchese et al. studies to develop a station-level emission factor which would significantly limit any evaluation of source-level emission trends over time. The small population size of the underlying Mitchell et al. study, the lack of emission source detail, and the numerous compounding assumptions made in the Marchese et al. study to "scale" the modeled results, may not provide sufficient certainty to use the study results for GHGI revisions to the Gathering and Boosting sector.

- Conversely, significant activity data will be available through the GHGRP in coming years. API urges EPA to delay significant revisions to the GHGI related to Gathering and Boosting until the GHGRP data are available. At that time, API recommends that EPA provide a separate accounting of activity data and emissions for Gathering and Boosting sources as a separate sector or as a subset of the Production sector.

- As stated previously in our comments on EPA's Transmission/Storage memo, API agrees that updated GHGI emissions data are warranted and as such recommends that EPA form a multi-stakeholder working group comprised of industry, governmental, and environmental organizations active in GHG emissions measurements and estimation to evaluate recently published data that may be used for updating the national GHG inventory. API proposes that such a working group be convened following the completion of the 2014 GHGI (April) to provide a structured framework for consultation and review of GHGI updates. An early start (April 2016) and frequent meetings (every 1-2 months) would provide sufficient time to review and consolidate information in an informed process for updating the 2015 GHGI and beyond.

- Additionally, API reiterates that the EPA should carefully analyze and screen GHGRP reported data in order to improve the validity of data used in the national GHGI. Obvious data errors and/or outliers should be assessed, corrected or excluded to prevent disproportionately impacting the derivation of emission factors (EFs) or extrapolation of information for the national GHGI.

Responses to EPA Questions for Revisions under Consideration for the Production Sector

General Use of Subpart W Data

✓ (Question #1 from EPA's Production memo) The EPA seeks feedback on how to take into account the reporting threshold when using Subpart W data, and the appropriateness of using Subpart W-based AFs for the national population of major equipment and pneumatic controllers.

a. Are other data sources available that would help the EPA determine characteristics of the non-reporting population?
b. Are other approaches available for scaling up this data for use in the GHGI?

API Comment: Although Subpart W does not capture all U.S. production operations, it is the most significant source of activity data available. We would expect that production operations not reporting through Subpart W are likely much smaller facilities, such as those associated with

stripper wells. It is reasonable to expect a difference in major equipment and pneumatic controller counts in these smaller facilities compared to facilities that meet the Subpart W reporting threshold. However, sufficient information for major equipment and pneumatic controller counts, for emission estimates, is lacking for the facilities that fall below the reporting threshold. Therefore, although API supports EPA's use of information available through the GHGRP to update equipment counts in the national inventory, a note of caution is advised when using the GHGRP pneumatic device count to characterize stripper wells or other smaller production well types, which tend to typically have fewer, if any, pneumatic controllers for their operations. As a result, the use of activity factors (AFs) based solely on average reporting data in the GHGRP will likely over-estimate equipment counts from non-GHGRP wells.

In addition, estimates of the coverage of the GHGRP would be expected to be different in each production basin depending on the characteristics of ownership (many small operators vs. larger companies), historical development trends, and type of production in the region. For example, a recent analysis of available data in the Barnett Shale[7] in 2013 found that the oil and gas well count in the GHGRP (15,900 wells) only represented 46% of the well count (34,800) derived from GHGI methods. In that same study, the author estimated 29,900 oil and gas wells from other available data. This discrepancy highlights the need for more transparency in GHGI well count methods, as API has previously commented (see Question #7).

The correlation between GHGRP and GHGI well counts would be expected to be worse in other production regions since much of the Barnett Shale development[8] has occurred over the last 8 years for shale oil and gas production, which typically includes more on-site production equipment and may be more likely to be reported under the GHGRP. In addition, some operators have begun to move towards multi-well pads and shared production equipment for multiple wells. Properly-scaling GHGRP and other activity factors to a national level is a difficult technical challenge that will require substantial data analysis and a multi-stakeholder group for proper implementation. Such a group should be convened in order to ensure that future changes to the GHGI represent a true and robust national emissions estimate.

Furthermore, under the GHGRP, companies report devices that do not emit as typical pneumatic controllers so the population of controllers in the GHGRP data is very different than the population measured in the GRI/EPA study (conducted in 1992-1993 and published in 1996) and it is erroneous to take the count of all such devices and scale them up to the national inventory by using the wellhead count and the emission factors from the GRI/EPA study. For example, emergency shutdown devices (ESD) are largely designed to emit only during a process upset in order to shut-in production. Given the infrequency of this type of event, it would be improper to characterize these controllers in the same way as the continuous vent pneumatics that are assumed as part of current GHGI inventory factors.

[7] Lyon, D.R., Zavala-Araiza, D., Alvarez, R A., Harriss, R., Palacios, V., Lan, X., Talbot, R., Lavoie, T., Shepson, T., Yacovitch, T. I., Herndon, S. C., Marchese, A.J., Zimmerle, D., Robinson, A. L. and Hamburg, S. P. *Constructing a spatially resolved methane emissions inventory for the Barnett Shale Region*, Environmental Science and Technology, **49**, 8147-8157, 2015

[8] http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/barnett-shale-information/

- ✓ (Question #2 from EPA's Production memo) The EPA seeks feedback on other data sources (e.g., Allen et al. 2013 and 2014, the Prasino Group 2013) that could be considered for the development of emission factors for equipment leaks and/or pneumatic controllers.
    a. Allen et al. 2014 study did not differentiate between controller types. Is it possible to disaggregate the Allen emissions data in a way that would allow the EPA to calculate emissions for various control types?

API Comments on Pneumatic Controllers: API commented previously[9] that the emission factors used for quantifying pneumatic controller emissions, especially the intermittent-bleed controller factor, largely overestimates these emissions. Therefore, if EPA intends to update the count of pneumatic controllers in the national inventory then EPA must also in parallel (or at the same time) update the emission factors.

EPA's current memo outlining methodological changes under consideration for estimating methane (CH_4) emissions from production operations does not refer to, nor draw on information EPA presented in its April 2015 memo on potential revisions to pneumatic controller emission estimates[2]. In the April 2015 memo, EPA summarized the following studies:

- Allen, D.T., Pacsi, A., Sullivan, D., Zavala-Araiza, D., Harrison, M., Keen, K., Fraser, M., Hill, A.D., Sawyer, R.F., and Seinfeld, J.H., *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers*, Environmental Science & Technology, 10.1021/es5040156.
- Oklahoma Independent Petroleum Association (OIPA), *Pneumatic Controller Emissions from a Sample of 172 Production Facilities*, November 2014.
- The Prasino Group, *Final Report- For Determining Bleed Rates for Pneumatic Devices in British Columbia*, December 18, 2013.
- The Independent Petroleum Association of Mountain States (IPAMS) and Western Regional Air Partnership (WRAP), 2006.
- Central States Air Resources Agencies (CenSARA), 2011.

In the April 2015 memo, EPA noted that the Allen et al. 2014 study (a.k.a UT/EDF Phase 2 Study) did not differentiate between controller types. However, supplemental information for the Allen et al. 2014 study does provide classification of pneumatic controllers by Subpart W types, for a subset of controllers and also determined classification based on gas flow time-series measured during the study for all measured controllers (refer to Table S4-2 from the Allen et al. 2014 study[10]). EPA could examine this information for updating emission factors for intermittent-bleed controllers. However, it may be more difficult to analyze the data for high-bleed versus low-bleed controllers since malfunctioning low-bleed controllers could exhibit characteristics of high-bleed controllers. It is our understanding that the Allen et al. 2014 study also collected meta-data for each controller that includes the manufacturer and model number of each controller and that this information is available upon agreeing to confidentiality provisions.

[9] Shires, T.; "Onshore Oil and Gas Production – Pneumatic Controllers", Presented at the Stakeholder Workshop on EPA GHG Data on Petroleum and Natural Gas Systems, November 19, 2015.
[10] Allen, D.T., Pacsi, A., Sullivan, D., Zavala-Araiza, D., Harrison, M., Keen, K., Fraser, M., Hill, A.D., Sawyer, R.F., and Seinfeld, J.H., *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers Supporting Information*, Environmental Science & Technology, 10.1021, Pneumatics es5040156_si_001.pdf

The manufacturer and model number would enable classification of each controller into the appropriate EPA "bucket" on the basis of the controller design rather than the measured emission profile.

Generally, the Allen et al. 2014 data showed lower emission rates per controller than the current emission factors in the GHGI. For example, the current GHGI emission factor for gas wells is 15.4 scf/hr/controller. On average, the estimate from the Allen et al. 2014 study was 5.5 scf/hr/controller, even accounting for emissions from malfunctioning controllers or related systems (i.e. a pinhole leak in the control valve) that were included in the emission factor for pneumatic controllers. There are reasons to believe that the current GHGI emission factor over-estimates the emissions from current controllers in operations. For example, many operators have changed out or retrofitted continuous high-bleed controllers as part of voluntary and regulatory programs.

The Oklahoma Independent Petroleum Association (OIPA) conducted an analysis of the Allen et al. 2014 pneumatic data to complement the data from the OIPA study, by including emissions from leaking or malfunctioning intermittent-bleed controllers. In the Allen et al. 2014 study, 10 of 320 intermittent-bleed controllers (3%) were "high emitters;" (i.e., were either leaking or malfunctioning and had an average "malfunctioning" emissions factor of 50 scf/hr). The OIPA study calculated an emission factor for vented emissions from intermittent-bleed pneumatic controllers of 0.4 scf/hr based on physical observations of actuation frequency and calculated volume of gas released per actuation. The distinction is that "vented" emissions from pneumatic controllers represent the gas released due to normal operation of the controller, while "malfunction" emissions from pneumatic controllers represent leaking or malfunctioning controllers. Applying the OIPA "vented" emissions factor of 0.4 scf/hr to 310 of the properly functioning intermittent-bleed controllers in the Allen et al. 2014 study, while applying the "malfunction" emissions factor of 50 scf/hr to the 10 leaking or malfunctioning intermittent-bleed controllers gives a weighted average emissions factor of 2.0 scf/hr for all intermittent-bleed controllers ($[(310 \times 0.40 \text{ scf/hr}) + (10 \times 50 \text{ scf/hr})]/320_{\text{controllers}} = 2.0 \text{ scf/hr}$). The OIPA study also provides information on the count of pneumatic controllers for new well sites and old well sites (including stripper wells and smaller conventional well pads). As shown in the OIPA study, a robust emission estimate must include understanding the characteristics of both of these types of wells.

Regarding the Prasino study, API cautions EPA in using data from that study as the focus was only on pneumatic controllers with manufacturer bleed rates > 6 scfh and thus the Prasino study is intentionally biased toward high emitting pneumatic controllers.

Overall, while all these recent studies present the most current data available, they likely should not be EPA's primary source of data due the variability from study to study. Addressing the use of new measurement data to update the GHGI would benefit from further evaluation of all available data by a multi-stakeholder working group. Such an approach would provide for a structured update of the applicable emission factors to complement the revised counts being obtained from Subpart W. If the EPA decides to update the inventory without such a stakeholder engagement, API recommends the use of the Allen et al. 2014 study emission factors for pneumatic controllers, as the best available current data set, which can also provide improved understanding of these emissions. As an area with expected future studies, EPA

should consider that understanding of emission rates from this source is likely to evolve in the near term as new data sets and measurement techniques are considered. API is interested in maintaining an on-going dialogue of emission sources in this sector.

- ✓ (Question #3 from EPA's Production memo) The EPA seeks feedback on how to take into account reported emissions data under Subpart W for major equipment fugitives in the GHGI. For reporters using equipment leak methodology 1 (98% of reporters in RY2014), emissions data are reported at the facility level based on use of component-level EFs specified in the rule, not at the equipment level. The EPA seeks feedback on how to use such data in developing equipment-specific fugitive EFs that could be applied in the natural gas and petroleum systems sectors of the GHGI. The Subpart W specified EF for reporting vented emissions from CIPs uses the same basis (GRI/EPA) as the current GHGI. The EPA is considering adjusting the GHGI emission factor for CIP using Subpart W reported data, which takes into account operating hours.

API Comment: Existing GHGRP data on fugitive emissions reported for the production sector is of limited value for the GHGI since it relies on a set of average emission factors per component counts as prescribed by EPA and does not contain measurement information that may be useful to update the emission factors. Equipment counts reported through Subpart W could be useful for updating activity data for the GHGI, but such extrapolations would be technically challenging as discussed in Question #1. As a result, API strongly encourages a detailed stakeholder process related to determining the best method for this extrapolation given the different populations of wells expected to be covered and not covered under the GHGRP. However, EPA should refrain from using the default component level emission factors specified for Subpart W to develop equipment-based fugitive emission factors for the GHGI.

Subpart W provides counts of chemical injection pumps (CIPs) and operating hours that can be used to scale up GHGRP data to a national emission estimate. However, Subpart W does not provide information to support updating the emission factor for CIPs. The Allen et al. 2013 study (a.k.a. UT/EDF Phase 1 study) provides measurement data for 62 CIPs with an average emission rate of 0.192 scf CH_4/min/device. EPA should consider evaluating this information for updating both the default emission factor available in Subpart W and the emission factor currently used in the GHGI.

Calculations Using Subpart W Data

- ✓ (Question #4 from EPA's Production memo) The EPA seeks feedback on the methodology for allocating Subpart W data between the natural gas and petroleum production sectors. Are other approaches available for allocating Subpart W equipment and pneumatic controller counts between production types? For example, one limitation in the current methodology is that for facilities covering both oil and gas sub-basins and having separators, the count of separators-per-gas well is equivalent to separators-per-oil well.

API Comment: Following IPCC guidance, EPA separately reports production operations for Natural Gas Systems and Petroleum Systems in production operations[11], while oil and gas production activities are combined in the GHGRP. EPA's current approach of separating GHGRP data based on the ratio of oil production basins to high permeability gas, shale gas, coal seam, or other tight reservoir rock, although somewhat arbitrary is reasonable.

To aid in comparing the GHGI to GHGRP data, API suggests that EPA resolve differences in emission source types between the two reporting programs and between natural gas and petroleum production activities. For example:

- Production operators report emissions from associated gas venting and flaring in the GHGRP, but this source is not included in the GHGI;
- Well drilling emissions are a vented source in the GHGI under Natural Gas Systems, but combustion and fugitive emissions from well drilling are tracked under Petroleum Systems;
- "Wellheads" are an equipment category for reporting fugitive emissions in the GHGRP, but the GHGI reports emissions for associated gas wells, non-associated gas wells (less wells with hydraulic fracturing), gas wells with hydraulic fracturing, oil wellheads (heavy crude) and oil wellheads (light crude).

These are just a few examples where inconsistencies in terminology complicate comparing emissions between the GHGRP and Natural Gas Systems and Petroleum Systems in the GHGI.

✓ (Question #5 from EPA's Production memo) The EPA seeks feedback on whether and how to use Subpart W data to reflect geographic variation of activity factors and/or emission factors. In the current GHGI, emissions from natural gas systems are calculated separately for six NEMS regions, and emissions from petroleum systems do not have geographic variation. The update under consideration is applied at the national level. The EPA plans to explore options to reflect geographic variation in future GHGIs.

API Comment: In the Natural Gas Systems production sector, EPA reports emission factors and activity factors by National Energy Modeling System (NEMS) regions. Except for fugitive emission factors, emission factors vary from year to year due only to slight changes in the methane composition between each NEMS oil and gas supply region. The methane compositions are derived from a 2001 GTI study[12] and adjusted year to year using gross production for NEMS oil and gas supply modelled regions from the EIA.

Distinctions made between eastern and western fugitive emission factors, derived from the 1996 GRI/EPA study were based on operational differences and the extent of production of sour crude, and are no longer relevant to operations today.

API recommends that EPA drop the breakout of natural gas production data by NEMS region. This breakout gives a false sense of data accuracy, as most of the emission factor variability is based on methane concentration and not on different operating practices. In addition, regional

[11] 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 1, Section 8.0 *Reporting Guidance and Tables*, Table 8.2

[12] GTI (2001) Gas Resource Database: Unconventional Natural Gas and Gas Composition Databases. Second Edition. GRI-01/0136.

data is not needed for the GHGI, as evidenced by the other natural gas and petroleum sectors that are only reported at the national level.

- ✓ (Question #6 from EPA's Production memo) The EPA seeks stakeholder feedback on year-to-year trends in reported Subpart W data, and whether it is more appropriate to recalculate activity factors and/or emission factors separately for each RY, or to use another approach (e.g., combine data from multiple early RYs such as the current methodology for hydraulically fractured gas well completions which uses combined RY2011 through RY2013 data to calculate the emission factor).

API Comment: For Subpart W, the 2011 and 2012 GHGRP data include estimates due to the use of BAMM, and for pneumatic controllers due to the option to estimate counts initially. In addition, data tend to improve over time as reporters become more familiar with the requirements and establish more robust reporting processes. API does recognize the value in using Subpart W data to reflect year to year trends. However, API suggests that early-year reporting data may not be as accurate as data reported in the third year and beyond. For production operations, API recommends that EPA use an average of 2013 and 2014 GHGRP data to update activity factors. As data become available for the Gathering and Boosting sector, EPA should recognize that reporting year 2016 will include the use of BAMM and even reporting year 2017 may reflect the learning curve in establishing reporting programs for this new sector.

- ✓ (Question #7 from EPA's Production memo) The EPA seeks feedback on how to address time series consistency in using AFs derived from Subpart W data—i.e., calculating activity in years between the early 1990s base year and recent Subpart W-era years. As discussed under "Time Series Considerations" the EPA might use the count of active production wells as an activity data driver for major equipment and total pneumatic controller counts in natural gas systems, and simple linear interpolation for petroleum systems. The EPA could consider taking into account other factors (e.g., year to year production changes). The EPA seeks stakeholder feedback on other factors that impact equipment counts and potential methods to incorporate these factors into the GHGI calculations.

API Comment: API examined the DrillingInfo (DI) Desktop data over the 1990-2014 period to determine if there are any unusual peaks or valleys in oil or gas well counts or production data. The trends for well counts and production data are generally the same, with no apparent outliers. Therefore, it seems reasonable for EPA to use national well count and production data to estimate emissions over the inventory time series.

However, API notes that obtaining accurate and replicable well counts is a complex issue. API is engaged in ongoing discussions with EPA about how to estimate well counts using the DrillingInfo (DI) database. At a primary level, these discussions revolve around differences in how the EPA accesses the DI data versus how API accesses the data. While EPA starts with actual raw data files, API accesses the data through a desktop application of the data that only allows for certain search parameters. This means that there are significant differences in how users can access and search the data, which makes it very difficult to replicate well counts. For example, because EPA has access to all raw well data, they are able to easily classify wells as either "oil" or "gas" based on a GOR that they calculate. Through the desktop application however, wells are classified as "oil" or "gas" based on state definitions that are not consistent

across all wells. The following table illustrates the differences in well counts accessed by API through the DI database, compared to well counts reported by EPA for 2013 in the previous GHGI[13]

DI Database Well Counts for 2013 (accessed by API)		EPA Reported 2013 GHGI Well Counts[13*]	
Gas Wells	417,277	Non-associated gas wells	207,279
		Gas wells with hydraulic fracturing	244,017
Gas and Oil Wells	70,679	Associated gas wells	477,023
Oil Wells	455,243	Heavy crude oil wells	38,682
		Light crude oil wells	510,005
TOTAL	**943,199**	**TOTAL**	**1,477,006**

* Including 315,000 crude oil stripper wells (<15 Bbls per day); Reference 13 Table A-126

Unless one downloads all of the well data, which is not a feasible solution, the desktop application does not allow a user to calculate a GOR and use it as a search parameter. API urges EPA to be transparent in describing how EPA utilizes information in Drilling Info for the GHGI in order to facilitate comparisons and ensure that there is no undercounting or overcounting of wells.

We would also like to point out that the noted discrepancies in the well counts are not a new issue. For example, the U.S. Energy Information Administration (EIA) reports 514,637 producing gas wells for 2011 (as compared to 604,681 in the GHGI published in 2013) and 536,000 producing oil wells (as compared to 220,787 crude oil wells and 315,213 crude oil stripper wells in the GHGI published in 2013). For 2013, the EIA reports 484,994 producing gas wells (with gas-oil ratio > 6000 scf/barrel) but does not furnish equivalent information for oil wells.

The well counts provided in EPA's Production sector memo equal 1,315,196 (Table 4: 2013 wellheads for petroleum & natural gas combined). This value is different from the sum one derives (per table above) from the respective petroleum and natural gas tables in Annex 3 of the 2013 GHGI. Since EPA is proposing to use the number of wellheads (well count) as the normalization factor for scaling Subpart W data, it is imperative that the well count be accurate.

API is providing all of these examples to highlight the discrepancies in the data used to update the emissions estimates for the production sector and the need to have them reconciled by a transparent and structured process via a multi-stakeholders group, as previously stated.

Other Emission Sources

- ✓ (Question #8 from EPA's Production memo) The EPA discusses potential revisions to the GHGI production sector structure in a companion memo titled "GHGI of U.S. Greenhouse Gas Emissions and Sinks: Revisions under Consideration for Natural Gas Gathering and

[13] U.S. EPA, 2015, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013", EPA 430-R-15-004, April 15, 2015; Tables A-126 and A-133.

Boosting Emissions" (February 2016). Potential revisions would include updating some of the production emission calculation methodologies based on Marchese et al. (2015) measurement data for centralized production and gathering-only facilities. With such revisions, certain emission sources would overlap with the Marchese et al. facility-level EF if current methodology were retained: dehydrator vents, Kinray pumps, and storage tanks. The EPA seeks feedback on how to improve GHGI activity, emissions, and controls data for sources located at non-gathering production sites based on available Subpart W data.

API Comment: EPA's memo on proposed revisions to the GHGI for Gathering and Boosting focuses entirely on utilizing information from the Mitchell et al. and Marchese et al. studies. However, the Mitchell et al. measurements are limited in their use because only downwind, site-level short-duration "snapshot" measurements were conducted. This approach does not provide sufficient information to properly characterize emissions at individual sites in gathering and boosting operations, much less individual sources within the sites.

API recommends that EPA postpone major updates to the GHGI for gathering and boosting emissions until GHGRP data are available. The GHGRP will provide additional activity data for gathering operations and will enable EPA to properly characterize equipment populations and distinguish between production and gathering. When this new information and characterization become available, API recommends that EPA revise the GHGI to present, separately, gathering emission estimates from production emission estimates, even if they ultimately have to be combined for reporting under the IPCC categories. This will align the inventory with the GHGRP, provide greater transparency, and enable trends to be evaluated. As stated above, API requests that EPA delay making any significant changes to the methodology until GHGRP data are available in 2017. At that time, EPA will have facility specific data for a significant number of Gathering and Boosting facilities in the country, including population information, activity data, and actual emission data for some sources.

- ✓ (Question #9 from EPA's Production memo) The EPA seeks stakeholder feedback on production sector sources not discussed in this memorandum.
  a. For sources where GHGRP data are currently available, the EPA seeks stakeholder feedback on how GHGRP data may be used to revise current GHGI methodologies. For example, the EPA seeks stakeholder feedback on whether similar methods to those discussed in this memorandum could be used to scale up subpart W activity data for sources such as liquids unloading and hydraulically fractured (HF) gas well completions
  b. For sources where GHGRP data are not currently available, the EPA seeks stakeholder feedback on data sources available for updates to those methodologies. The EPA is considering including emissions from hydraulically fractured oil well completions and workovers in the GHGI, using information from the 2015 NSPS OOOOa proposal. In addition, the EPA seeks stakeholder feedback on any currently available or upcoming activity and/or emissions data on abandoned wells.

API Comment: (a) For emission sources with data available through the GHGRP, API recommends that EPA make use of GHGRP information to update the national inventory. As mentioned in our responses above, the exception to this is where the GHGRP does not collect new emissions data but utilizes default emission factors, such as for fugitive emissions in production, pneumatic controllers, pneumatic pumps, compressors in production, and small dehydrators.

API previously commented on the use of GHGRP data for gas well completions and workovers to update emission estimates in the GHGI.[14] EPA incorporated updated emission factors for these sources, although API continues to believe that the emissions data can be well represented by only two emission factors (completions and workovers vented without REC, and all other completions and workovers) rather than the four categories used by EPA. These two categories maximize the use of GHGRP data, will be more straightforward to back cast for previous reporting years in the GHGI, and are consistent with current practices.

API cautions EPA against using the ratio of well completions and workovers to overall well counts in the GHGRP, in order to scale up completion and workover counts to the national level. Completions, by definition, only apply to new wells, although not all new wells are hydraulically fractured. Information on new wells should be available through EIA or DI Desktop. Determining an appropriate method of scaling GHGRP data may be best achieved through discussions and consideration by the multi-stakeholder group suggested by API.

(b) Although not currently required under the GHGRP, some companies have reported emissions data for oil well completions and workovers with hydraulic fracturing. API commented previously on the use of GHGRP data to derive emission factors for the GHGI.[14] API previously identified 149 reported data sets, providing emissions data for 1675 completions and 226 workovers for the years 2011 through 2013 combined (we have not examined the 2014 GHGRP data to update this analysis). API believes the GHGRP provides sufficient data to include these emissions in the GHGI, and that much more information will be available in the next few years to update the national emission estimates.

The DI database provides activity data for abandoned wells. A 2014 study (Kang et al.[15]) provides information on emissions from abandoned wells in the Appalachia region. However, many of these wells are very old, predate any abandonment criteria, were not properly abandoned and were limited to a single geographic region. Therefore, while the study did provide new information, the findings should not be considered as representative nor used as the basis for national extrapolation. A proper data set is needed that reflects geographical variability and well-age to represent emissions from abandoned wells on a national basis.

- ✓ (Question #10 from EPA's Production memo) Recent production sector studies have detected the presence of super emitters in the production sector. The EPA seeks stakeholder feedback on how to incorporate information on super emitters into estimates for the production sector. The EPA also seeks stakeholder feedback on which GHGI sources are more likely than others to act as super emitters and whether and how to apply a super emitter factor or other methodology to those sources.

[14] Letter to Leif Hockstad and Melissa Weitz, API Expert Review Comments on EPA's Draft U.S. GHG Inventory: 1990-2013, January 9, 2015.
[15] Kang et al. (2014) "Direct Measurements of Methane Emissions from Abandoned Oil and Gas Wells in Pennsylvania". Proceedings of the National Academy of Sciences of the United States of America. Available at: http://www.pnas.org/content/111/51/18173.full.pdf]

API Comment: Recent measurement studies have shown skewed "long tail" distributions for source-level measurements, where a few emission sources may contribute a disproportionately high fraction of emissions. This is a common and expected statistical distribution for random events, such as fugitive emissions from process components and equipment malfunctions. A combination of variability in production and non-steady state emissions may result in a 'fat-tail' distribution even in the absence of operational upsets. Emission factors derived from such measurements already account for the emission distributions throughout the range of observations for each of the sources, including the emissions at the high range of the tail.

The approach raised by EPA, of potentially, separately adjusting the national inventory for the so called 'super emitters,' is not appropriate. API contends that there should not be *any consideration* of using downwind offsite measurements – especially those that depend on short duration, snapshot measurements – to characterize emissions in the GHGI. Recent studies in the Barnett Shale region indicate that there might be several order of magnitude differences in repeated emissions from a given set of sites, probably due to stochastic variables that are transient in nature. In particular, a study of 22 separate flights around the same compressor station[16] indicated that facility-level emissions ranged from 0.3 to 73 g CH_4/sec with highly skewed distributions (mean=14 g/sec and median = 7.4 g/sec). Again, API suggests that the EPA inventory team consult with the EPA ORD's Eben Thoma regarding the adequacy of downwind ambient concentration measurements in determining emissions.

All the studies aiming to quantify fugitive emissions indicate that the distribution of emissions and the shape of its tail are not well understood. API insists that both EPA and the scientific community do not have enough information to identify the reasons for the variability of some emission sources. All measurements have some degree of uncertainty. This is especially true for short duration snapshot measurements conducted offsite, which fail to differentiate between routine episodes of high emissions, operating conditions, or operators errors that may lead to periodic higher emissions. For example, one study[17] focused on "super-emitter" quantification in the Barnett Shale and relied on measurements of 1-5 minutes in duration at distances of up to several kilometers downwind in a region with high oil and gas site density.

EPA's ORD research[5] that was conducted with strict data quality control parameters, longer sampling times, and nearer pad sampling, indicated that, at best, downwind measurements provide screening level accuracy with ±60%. Insufficient research exists to validate high downwind measurements with on-pad emission sources such that it could be used to characterize national emission estimates for a program like the GHGI. API concurs with EPA's ORD that in order to properly quantify emissions measurements, they should be taken over a long period of time in order to capture the full range of variability, rather than rely on just peak emissions. Assuming that peak emissions occur all the time would lead to biased results.

[16] Nathan, B.J., Golston, L. M., O'Brien, A.S., Ross, K. Harrison, W. A., Tao, L., Lary, D. J., Johnson, D. R., Covington, A. N., Clark, N. N., and Zondlo, M. A., *Near-field characterization of methane emission variability from a compressor station using a model aircraft.* Environmental Science & Technology, **49,** 7896–7903 2015

[17] Yacovitch, T. I., Herndon, S.C., Pétron, G., Kofler, J., Lyon, D., Zahniser, M. S. and Kolbacovitch, C. E. et al. *Mobile laboratory observations of methane emissions in the Barnett Shale region.* Environmental Science and Technology. **49**, 7889–7895, 2015

In summary, API maintains that adjusting emissions for what EPA terms 'super emitters' may lead to gross overestimation due to the unpredictable nature of such high emissions events and may also lead to duplicative counting, since these events are already part of the emission distribution that is used to derive emission factors. For example, if a connection failure is posited as the cause of a theoretical site being deemed as a theoretical "super-emitter", emission factors developed from in-field measurements of a population of connectors already account for some of these components emitting at a high rate. Consequently, API insists that since EPA does not have sufficient information to characterize and understand this then no such adjustment to the GHGI inventory approach should be considered.

Responses to EPA Questions for Revisions under Consideration for Gathering and Boosting Emissions

Data Availability

- ✓ (Question #1 from EPA's Gathering and Boosting memo) The EPA is seeking stakeholder feedback on additional data available to consider in revising G&B emission estimates at this time. The EPA seeks stakeholder feedback on the proposed approach to use Marchese et al. estimates for national activity data. Are additional data sources or approaches available to estimate national G&B activity?

API Comment: The Marchese et al. study results are based on facility level, downwind short-duration "snapshot" measurements conducted during the Mitchell et al. study. Marchese et al. used that data to model the total methane emissions from approximately 120 facilities. The modeled results are then "scaled" – using multiple assumptions - to a national level to represent the methane emissions from over 4,500 Gathering and Boosting facilities.

As indicated in our general comments, API urges EPA to wait on any significant revisions to the GHGI related to Gathering and Boosting until the GHGRP data are available. Significant activity data will be reported through the GHGRP, including throughput volumes and equipment counts. This information will be superior to the Marchese et al. study for developing national Gathering and Boosting activity data.

- ✓ (Question #2 from EPA's Gathering and Boosting memo) Replacing current GHGI EFs for large reciprocating compressors and stations with the EF based on Marchese et al. G&B station emissions may introduce double counting of the "mixed category" sources based on current GHGI methodology. The EPA's updates under consideration for the G&B sector (this memorandum) and production sector (Inventory of U.S. Greenhouse Gas Emissions and Sinks: Revisions under Consideration for Natural Gas Production Emissions (February 2016)) in combination avoid potential double counting issues by calculating emissions for each as distinct sectors. Please comment on the overall approach under consideration for production and G&B.

API Comment: The Mitchell et al. study relies on offsite, downwind measurements, using inverse flux methodology to derive emissions over short durations. These types of measurements have significant uncertainty, which has been documented by EPA's ORD[5]. EPA's proposed approach to segregate Gathering and Boosting emissions from Production is specifically designed to utilize data from the Marchese et al. study[4], which is a desktop modeling study based on the Mitchell et al. measurements[3] but is inconsistent with the Mitchell

et al study. API does not support the use of the emissions data from the Mitchell et al. or Marchese et al. studies for updating the GHGI.

The API further cautions the EPA on the development of new national emissions factors based on the Mitchell et al. study due to the large degree of variability and small sample size for the study. For the 114 facilities, emission rates ranged more than 4 orders of magnitude (from 0.6 to 600 scf CH_4/minute). Part of this variability is inherent in the short sample durations for the plumes in the study (30-120 seconds). Given the wide variation in facility emission rates from a study of 22 separate flights around the same compressor station[16], which indicated that facility level emissions ranged from 0.3 to 73 g CH_4/sec with highly skewed distributions (mean=14 g/sec and median = 7.4 g/sec), more context is needed for understanding emission rates in the Mitchell et al. study before considering application to national emission estimates.

In attempting to avoid double counting of emissions sources, EPA is artificially defining Production versus Gathering and Boosting equipment. For example, EPA is proposing to assign emissions from all pneumatic controllers, chemical injection pumps, dehydrator vents, and Kimray pumps to the Production sector. This will give the false impression that these sources only occur in Production.

API recommends that EPA wait until data are available through the GHGRP for the Gathering and Boosting sector. We believe this information will better represent the emission sources associated with Gathering and Boosting (recognizing that some Gathering and Boosting operations will continue to be reported under the Production sector due to the location of a well at the Gathering/Boosting site). In addition, we recommend that EPA report emissions from Gathering and Boosting separate from the Production sector, or as a subset of the Production sector. This will provide greater transparency and comparison to the GHGRP than combining Gathering as part of the Production sector, as is currently reported in the GHGI.

- ✓ (Question #3 from EPA's Gathering and Boosting memo) As discussed in this memorandum, G&B data will be available in 2017 through GHGRP. GHGRP data could allow the EPA to calculate emissions for individual equipment types as opposed to using emission factors and activity data at the station level. The EPA seeks stakeholder feedback on the two approaches. The EPA could considering using the station level approach for the 2016 GHGI, and then re-evaluating and potentially revising the approach with new GHGRP data in the 2017 GHGI, or could consider implementing updates to the G&B sector starting with the 2017 GHGI and using GHGRP and/or the Marchese et al. data at that time.

API Comment: API does not believe the Marchese et al. study results are appropriate for updating the national inventory and encourages EPA to wait until the Gathering and Boosting data are available through the GHGRP. As EPA indicates, the GHGRP data will allow the EPA to calculate emissions for individual emission source types as opposed to using emission factors and activity data at the station-level. Data for individual equipment types will be significantly more useful and transparent than emission factors and activity data at the station level. There is no need to introduce a significant revision to the GHGI now to accommodate the Marchese study information, only to later have to significantly revise the methodologies again to utilize the GHGRP data.

- ✓ (Question #4 from EPA's Gathering and Boosting memo) The EPA seeks feedback on whether and how to use the Marchese et al. data to reflect geographic variation of activity factors and/or emission factors. In the current GHGI, emissions from G&B sources are calculated separately for six NEMS regions along with production sources. The update under consideration would be applied at the national level. The EPA plans to explore options to reflect geographic variation in future GHG inventories.

API Comment: The small population size of the underlying Mitchell et al. study, the lack of emission source detail, and the numerous compounding assumptions made in the Marchese et al. study to extrapolate the modeled results do not provide sufficient certainty to use the study results to characterize the Gathering and Boosting Sector. Nor does the Marchese study provide sufficient information to characterize geographic variability. As mentioned above, in response to questions raised in the Production memo, API recommends that EPA discontinue breaking out natural gas production data by NEMS region and instead report Production sector emissions data at the national level only, as EPA does for the other sectors under Natural Gas Systems and Petroleum Systems. Similarly EPA should not attempt to calculate emissions from the Gathering and Boosting sector for individual NEMS regions.

Time Series Considerations

- ✓ (Question #5 from EPA's Gathering and Boosting memo) The EPA seeks feedback on the appropriateness of using the Marchese et al. based G&B station EF across all years of the time series, or whether there are approaches that may be considered for reflecting changing industry trends impacting emissions over time.

API Comment: The Marchese et al. study, which is based primarily on drive-by, snap-shot measurements from the Mitchell et al. study, does not provide useful data for characterizing current national emissions, nor does it provide sufficient information to reflect emission trends over time.

- ✓ (Question #6 from EPA's Gathering and Boosting memo) The EPA seeks stakeholder feedback on the activity driver (volume of marketed onshore gas production) under consideration. Other options for the activity driver could include well count data or other gas production categories. Please comment on which activity driver would be the most appropriate to show trends in G&B.

API Comment: EPA will have significant activity data reported for the Gathering and Boosting sector through the GHGRP starting in 2017. API recommends that EPA evaluate this information when it's available to identify activity drivers for scaling Gathering and Boosting emissions data to a national level. API also points out that it may take more than one reporting cycle to work through data quality concerns associated with the first year of reporting for a new sector.

- ✓ (Question #7 from EPA's Gathering and Boosting memo) The EPA seeks stakeholder feedback on trends in G&B activity data that would result in more or fewer stations per volume of marketed onshore gas production during any point in the GHGI time series. The EPA requests stakeholder feedback on how upcoming subpart W G&B activity data (available in 2017) could be used to inform the time series activity data to reflect ongoing trends.

API Comment: As noted in our comment to question #6, API expects the activity data reported through the GHGRP for the Gathering and Boosting sector to provide significant information for developing national scaling factors and similarly will be appropriate data for informing activity data over the time series.

- ✓ (Question #8 from EPA's Gathering and Boosting memo) Since the EIA does not publish separate values for the onshore portion of marketed natural gas production prior to 1992, the EPA is considering using the relationship of onshore marketed production to onshore gross withdrawals in 1992 to estimate marketed onshore production in 1990 and 1991, based upon onshore gross withdrawals for these two years. Are there alternatives to addressing this missing AD?

API Comment: API supports EPA's proposal to relate onshore marketed production to onshore gross withdrawals in 1992 in order to estimate marketed onshore production in 1990 and 1991.

- ✓ (Question #9 from EPA's Gathering and Boosting memo) Although it is not possible to directly compare the G&B emissions estimate developed with GRI/EPA study data to the Marchese et al. results, it is evident that the G&B emissions from Marchese et al. are significantly higher than estimates in the current GHGI. The EPA seeks stakeholder comment on this discrepancy.

API Comment: It is not appropriate to compare the Marchese et al. modeling information which is based on short-duration, off-site ambient concentration measurements, which rely on inverse flux methods to derive emissions; to source specific emission estimates. The site level measurements conducted in the Mitchell et al. study significantly limit the use of the data for updating the national inventory, which is compiled from source level emission estimates. API urges EPA to delay revising the emission estimation methods for the Gathering and Boosting sector until more data is available for this sector through the GHGRP.

Gas Processing

- ✓ Marchese et al. also measured the methane emissions from 16 natural gas processing plants using a similar approach as described above for G&B stations. The results of the Marchese et al. testing were scaled to the estimated 600 national gas processing plants using a similar Monte Carlo simulation as was used for G&B stations. The results of the Marchese et al. simulation was a national methane emission estimate for gas processing plants of 506 Gg. As with the G&B stations, Marchese et al. estimated that the emission results were biased low for several factors. The brief sampling period did not capture routine maintenance and upset emissions. In addition the sampling method did not capture a significant portion of the compressor exhaust emissions. Marchese et al. compared their findings to the EPA GHGI of 2012 emissions. The net GHGI methane emissions for 2012 from processing plants were 891 Gg. The net GHGI emissions from processing plants, excluding compressor exhaust and blowdown/venting emissions were estimated to be 666 Gg. EPA seeks stakeholder comment on the potential use of Marchese et al. results for the processing sector.

API Comment: As mentioned previously, measurement data from the Mitchell et al. study are not particularly useful for updating the GHGI because the data lack emission source detail. Substantial new activity data and some measurement data are available for gas processing

facilities that report through Subpart W. EPA now has four years of fugitive emission surveys and measurement data for specific emission sources and activity data that can be used to update the GHGI. API encourages EPA to make use of the survey results and actual measurements reported in GHGRP. In the November 2015 stakeholders' workshop, API presented a preliminary comparative analysis of methane emissions from equipment leaks from natural gas processing, showing that it is about six times larger in the GHGI as compared with the GHGRP. Although the number of gas plants reporting to the GHGRP is different than the number of gas plants in the GHGI, this difference cannot fully account for the emission differences. API would welcome further collaboration with EPA to address these differences and develop a procedure that incorporates the GHGRP measurement data in the GHGI.

API's comments above are based on our long term engagement in reviewing and providing information for the U.S. GHG Inventory. It includes observations and recommendations for careful QA/QC of data extracted from the mandatory GHGRP to improve the validity and representativeness of data used for the U.S. GHG Inventory. API recognizes that emerging data from recent field studies have raised concerns about measurements uncertainty, and recognizes the need for a thorough discussion of means of improving the methodology to ensure collection of robust measurement data. We reiterate our recommendation for EPA to form a multi-stakeholder workgroup to discuss updating the national GHGI to incorporate information from recent measurement study results and Subpart W data.

API appreciates the opportunity to provide comments on the proposed revisions to the U.S. national GHG Inventory and EPA's willingness to work with industry to improve the data used for the national inventory. API encourages EPA to continue these collaborative discussions and is available to work with EPA to make best use of the information available under the GHGRP to improve the national emission inventory. We look forward to continuing our collaborative work in the GHGI development process.

Sincerely,

Karin Ritter

cc: Alexis McKittrick, Climate Change Division

Appendix D

Environmental Science & Technology

Article

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Assessment of Methane Emissions from Oil and Gas Production Pads using Mobile Measurements

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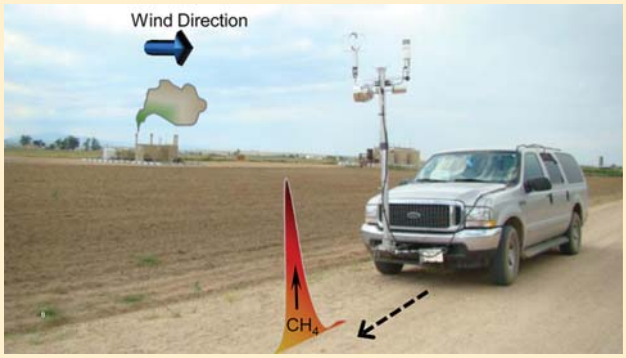
Supporting Information

ABSTRACT: A new mobile methane emissions inspection approach, Other Test Method (OTM) 33A, was used to quantify short-term emission rates from 210 oil and gas production pads during eight two-week field studies in Texas, Colorado, and Wyoming from 2010 to 2013. Emission rates were log-normally distributed with geometric means and 95% confidence intervals (CIs) of 0.33 (0.23, 0.48), 0.14 (0.11, 0.19), and 0.59 (0.47, 0.74) g/s in the Barnett, Denver-Julesburg, and Pinedale basins, respectively. This study focused on sites with emission rates above 0.01 g/s and included short-term (i.e., condensate tank flashing) and maintenance-related emissions. The results fell within the upper ranges of the distributions observed in recent onsite direct measurement studies. Considering data across all basins, a multivariate linear regression was used to assess the relationship of methane emissions to well age, gas production, and hydrocarbon liquids (oil or condensate) production. Methane emissions were positively correlated with gas production, but only approximately 10% of the variation in emission rates was explained by variation in production levels. The weak correlation between emission and production rates may indicate that maintenance-related stochastic variables and design of production and control equipment are factors determining emissions.



INTRODUCTION

Environmentally responsible development of oil and gas assets requires an understanding of atmospheric emissions of methane (CH_4) and other organic pollutants as well as their potential impact on local and regional air quality and greenhouse gas budgets. Emissions are associated with many different processes in upstream (well development and production) and midstream (transportation and storage) oil and gas activities.[1,2] Although differing in profile, emissions occur in all phases of well construction, drilling, and completion, and continue as part of the ongoing production processes.[3] Oil and gas production pads (pads) typically consist of well heads, separation units, and storage tanks. Emissions from pads can be difficult to measure and model due to temporal variability and the large number of potential sources.[4,5] Pad emission profiles depend on a variety of factors including the geological formation, equipment design and maintenance state, and on operational procedures. For example, depending on engineering and control strategies, atmospheric-pressure condensate storage tanks are a significant potential source of emissions and can be challenging to measure.[6,7] Pad emissions can also vary over time as wells age and production levels and pressures change. Improving our understanding of emissions from production sites requires a combination of approaches, including estimating emissions using engineering calculations for inventories,[2,8,9] direct measurements for refinement of emission and activity factors,[10] and new inspection techniques to inform departures from routine operations and support compliance activities.[11]

Direct (onsite) measurements can provide information on component-level emissions, but are resource intensive, requiring site access and special safety considerations. Furthermore, the high site-to-site variability decreases the probability of obtaining a representative sample from a small number of sites. To complement direct measurement approaches, a number of research groups are investigating the use of mobile inspection techniques to locate and assess emissions from off-site observing locations.[4,12−14] These emerging approaches vary with respect to execution requirements and emission estimation techniques; however, their mobile nature facilitates identification of unknown emission sources (e.g., pipeline leaks) and anomalous operating

Received: June 24, 2014
Revised: September 23, 2014
Accepted: November 6, 2014
Published: November 6, 2014

conditions (e.g., malfunctions). Unlike direct measurements, mobile approaches typically cannot isolate specific emitting components and are generally less precise than direct measures but are comparatively easier to implement, enabling emission assessments to be made at a greater number of locations on a more routine basis.

This paper describes a novel mobile inspection approach, EPA Other Test Method (OTM) 33A,[17] and its use to generate CH_4 emission rate data from oil and gas production sites in the Denver-Julesburg (DJ) Basin, the Barnett Shale, Pinedale, and Eagle Ford from 2010 to 2013. OTM 33A uses a combination of mobile sampling to identify sources and stationary measurements to quantify emissions. In addition to the analysis of repeated measurements at nine sites, the emission estimates from the OTM 33A field studies were compared with recent on-site studies led by the Eastern Research Group (ERG)[15] and Allen et al.[16] The ERG study,[15] conducted for the City of Fort Worth, TX, used both direct measurement and source estimation methods to characterize CH_4 and volatile organic compound emissions at 388 production sites containing wells, produced water storage tanks, separators, and compressors. Component-level source identification in the ERG study[15] was accomplished by infrared camera observations and direct source measurements were conducted using Hi Flow samplers (Bacharach Inc., New Kensington, PA), toxic vapor analyzers, and evacuated canisters. The measurements were used by the City of Fort Worth to evaluate the adequacy of setback provisions for pads and compressor stations. The results of the ERG study[15] indicated that compressors, leaking tank thief hatches, and pneumatic valve controllers are the most frequently encountered and significant emissions sources of CH_4. Using similar on-site measurement techniques, Allen et al.[16] measured CH_4 emissions from 150 production sites in four regions of the United States to evaluate engineering estimates of CH_4 emissions from natural gas production that are used in national inventories. Their results indicated that emissions from pneumatics and equipment leaks were higher than estimated in the EPA greenhouse gas (GHG) emissions inventory.[16]

MATERIALS AND METHODS

OTM 33A[17] is a mobile inspection approach used to locate sources and determine real-time emission rates with screening-level accuracy (±60%), without the need for site access or location-specific modeling. The technique is applicable to select oil and gas sources such as roadway proximate pads located in relatively open areas. In addition to downwind vehicle access and favorable plume transport conditions required for all mobile assessment methods, the emission characterization portion of OTM 33A relies on relatively consistent meteorological conditions, obstruction-free line of sight observation, and a knowledge of the distance to the source.[17]

Sampling Platform Design and Protocol. The OTM 33A equipment configuration, further described in OTM33A Appendix A,[17] used either a G1301-fc cavity ring-down spectrometer (Picarro, Inc., Santa Clara, CA) or a GG-24-r off-axis integrated cavity output spectrometer (Los Gatos Research Inc., Mountain View, CA) as CH_4 concentration measurement instruments (CMIs). The mobile measurement platforms were sports utility vehicles containing the CMI, computer control system, and battery systems allowing engine-off instrument operation during stationary observations to prevent self-sampling of vehicle exhaust. The vehicles were fitted with rotatable front-mounted masts with a height of 2.7 m allowing the CMI probe and meteorological instruments to be located away from the body of the vehicle. Primary wind field data were acquired using a model 81000 V Ultrasonic Anemometer (R.M. Young, Inc., Traverse City, MI). A collocated compact weather station (model AIO 102780, Climatronics Corp., Bohemia, NY) provided secondary wind data along with temperature, atmospheric pressure, and relative humidity measures. Location was recorded using a Hemisphere Crescent R100 Series GPS system (Hemisphere GPS, Calgary, AB Canada). A LabView (National Instruments, Inc., Austin TX) computer program time-aligned the data stream while allowing user control of the system.

The accuracy, linearity, and range of the CH_4 CMIs were confirmed in predeployment testing with in-field accuracy verified to be within ±5% of actual using nominal 20 ppm CH_4 (air balance) gas standard challenges as per OTM 33 Section 9.4.[17] The CMI readings were not corrected for atmospheric water vapor (OTM 33A Appendix A)[17] which introduces an approximate 1.5% average negative bias to CH_4 emission determinations for the conditions encountered in this study.

For a typical pad assessment, emissions were located through downwind, drive-by inspection, keying on sharply elevated CH_4 spikes indicative of proximate source plumes. Maximizing real-time CH_4 concentrations measured by the CMI, the vehicle was positioned in the plume at a safe and appropriate downwind observing location with the probe facing the source, and the engine was turned off. Distance from the measurement vehicle to the emission source ranged from 10 to 200 m with an average distance of 57 m. Data were acquired for a 15 to 20 min time period with the vehicle remaining stationary. Auxiliary data from infrared cameras (FLIR Systems, Inc., Boston MA), when available, helped identify the source location, facilitating laser rangefinder measurements of the distance from the mobile platform to the source. Distances were later confirmed through Google Earth images coupled with wind-concentration rose data. The vehicle was positioned to minimize line-of-sight wind flow obstructions.

Emission rate estimates were calculated using a point source Gaussian (PSG) approach with a custom MATLAB (MathWorks, Natick, MA) analysis program (OTM 33A Appendix F1).[17] This approach relies on variations in wind direction to move the plume around the observation location in three dimensions; further assumptions include a point source and Gaussian plume dispersion. The analysis software time-aligned the measurements to correct for sampling line delay, rotated the 3-D sonic anemometer data to polar coordinates centered on the predominant wind direction, and binned the CH_4 concentrations by wind direction data in ten degree increments. The results were fitted with a Gaussian function to determine the average peak CH_4 concentration in the plume. Background concentrations were determined by the program during time periods with no plume-probe overlap (OTM 33A Section 8.7).[17] The program calculated the representative atmospheric stability indicator (ASI) from an average of the turbulence intensity (TI), measured by the 3D-sonic anemometer and the standard deviation in 2-D wind direction ($\sigma\theta$), acquired by the compact meteorological station. By defining a seven unit ASI scale with steps of equal increments (TI = 0.025, $\sigma\theta$ = 4.0°), an ASI value for each measurement was assigned which ranged from 1 (TI > 0.205, $\sigma\theta$ > 27.5°) to 7 (TI < 0.08, $\sigma\theta$ < 7.5°), roughly corresponding to the Pasquill stability classes A through D.[18] For the PSG emission estimate, the values of horizontal (σy) and vertical (σz) dispersion are determined

from an interpolated version of point source dispersion tables using the measured source distance and the ASI (OTM 33A Section 12, Appendix F1).[17] The PSG emission estimate (q) is a simple 2-D Gaussian integration (no reflection term) multiplied by mean wind speed (u) and the peak concentration (c) determined by the Gaussian fit: ($q = 2\pi{\cdot}\sigma y{\cdot}\sigma z{\cdot}u{\cdot}c$).[17]

Method Validation Using Controlled Release Experiments. A set of 107 controlled CH_4 release experiments were conducted to investigate data quality indicators and the expected accuracy range for the PSG approach in relatively obstruction-free, open areas as encountered in this study (OTM 33A Section 9).[17] The experiments used single point releases from slightly dispersed, mass flow-controlled cylinders of 99.9% CH_4, performed at a variety of site locations, observation distances, and under a range of atmospheric conditions. Release rates ranged from 0.19 g/s to 1.2 g/s with 60% at approximately 0.6 g/s. Based on these experiments, a primary set of three data quality indicators was identified: (1) fitted peak CH_4 concentration centered within ±30 degrees of the source direction; (2) an average in-plume concentration greater than 0.1 ppm; and (3) a Gaussian fit with an $R^2 > 0.80$. The plume centering indicator helps ensure the identity of the upwind source and can protect against off-axis interfering sources and poor plume advection conditions. The concentration limit helps protect against insufficient plume transport and the R^2 indicator helps identify interfering sources and obstructed wind flow conditions (non-Gaussian transport).

The percent error ([estimated emission rate-release rate]/[release rate]) of the controlled release experiments that met the data quality criteria ranged from −60% to 52% with 72% of the measurements within ±30%. Without application of the data quality indicators, the set of release experiments produced accuracy values ranging from −87% to 184% of actual. The 184% overestimate was believed to be due to pooling and release under partially stagnant conditions and a trial wind variance indicator was developed for this case (not observed in field trials). Factors affecting accuracy can include insufficient plume advection and nonrepresentative concentration profiles caused by near-field obstructions or poor plume-probe overlap. Potential data quality indicators such as wind speed and plume concentration statistics are being investigated as part of OTM 33A method development.[17] For the current analysis, only measurements that met the three primary criteria were included (representing 77% of the controlled release measurements and 71% of the field measurements).

Description of Field Studies and Production Data. OTM 33A was used in eight two-week field campaigns in four oil and gas production basins: Colorado DJ Basin, July 2010 and 2011; Texas Barnett shale, September 2010 and 2011; Texas Eagle Ford Shale, September 2011; and Wyoming Pinedale, which includes the Pinedale Anticline and Jonah fields, June 2011, July 2012, and June 2013. Data sets for each individual basin were combined as the methods of data collection were similar, although there were some software and hardware improvements in later studies. All measurements were collected in the daytime on days with no significant precipitation.

Oil and gas production information for the counties sampled was obtained from DI Desktop (Drillinginfo, Austin, TX). Included in the data set were well type, operator, first production date, spatial coordinates of the well, and annual and monthly hydrocarbon liquids, gas, and water production levels. OTM 33A measurements were spatially matched with production data using aerial imagery (Google Earth[19] and ArcGIS[20] base maps). When coordinates did not align with aerial imagery, additional data sets provided by the State of TX[21] and State of CO[22] were used to cross-reference location information. Monthly production values were available for 81% of the measurements. When monthly production was not available, annual values were converted to monthly estimates. The matched data set was analyzed using R[23] and ArcGIS 10.[20]

Both emissions estimates and production values were log-normally distributed and for this reason, data in figures are shown on a log scale. The mean and 95% CI of the log-transformed data were calculated using a nonparametric bootstrap[24,25] and then transformed back into the original scale. The nonparametric bootstrap involved resampling with replacement 1000 times, the mean of each of the samples was taken and the 95% CIs were calculated from the resulting normally distributed means. The nonparametric bootstrap was chosen because it does not assume the underlying data comes from a normal distribution. To compare OTM 33A emissions estimates with the direct measurement studies conducted by ERG[15] and Allen et al.,[16] direct measurements were converted from CH_4 scfm into g/s using a molar volume of 40.87 mol m^{-3} and summed by site. Measurements from the ERG study[15] were matched with the corresponding monthly production values from DI Desktop (Drillinginfo, Austin, TX) based on the recorded Entity ID. Production values for the sites measured by Allen et al.[16] were reported by the well operators to the study team.

RESULTS AND DISCUSSION

Description of Sites with Repeat Measurements. The OTM 33A mobile inspection approach was used to identify and assess CH_4 emissions from roadway proximate well pads with an average in-plume concentration enhancement over back ground >0.1 ppm. No attempt was made to measure or statistically account for well pads with apparently low (and thus difficult to measure) emissions. In many cases, infrared camera videos (examples in Supporting Information (SI) Supplemental B) acquired from off-site observing locations, simultaneously with the CH_4 measurements, helped to identify specific emission sources. Storage tank-related emissions were frequently observed. The emission rates and video examples presented here may not be representative of current conditions due to engineering advancements, changes in work practices, and the implementation of new state regulations.

To improve understanding of both technique and source variability, repeat measurements (three or more) were made at nine sites in the Pinedale Basin, with the number of measurements per site ranging from 3 to 21 (SI Table S1). The consistent winds and lack of obstructions in the Pinedale Basin create favorable conditions for OTM 33A. Measurements were made in different years at four of these sites (Figure 1), and the time between measurements ranged from <1 day to 732 days (SI Table S1). For sites A−G, the 95% CI for the geometric mean was less than 1 g/s while at sites H and I, large variations in emissions were observed, resulting in a CI ≥ 2 g/s (SI Table S1).

The results indicate that while relatively low emissions (<2 g/s) frequently persist over time, the larger emissions observed using OTM 33A are likely episodic in nature. One source of persistent low-level emissions observed with the infrared camera is believed to be a vented produced water tank at Site C (SI Video S1). Previous studies have shown that flashing

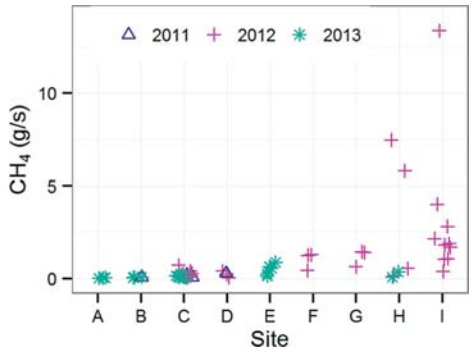


Figure 1. CH_4 emission rates (g/s) measured at repeated sites in Pinedale, WY by year.

from a condensate tank after a separator dump can result in episodic large emissions.[6] CH_4 emissions greater than 2 g/s were observed at 13% of the 210 unique sites measured. The variability of emission rates at sites H and I indicates that these larger emissions may be episodic events that cannot be used to infer annual emission rates without a greater understanding of their frequency and duration (Figure 1).

Site I was measured on four separate days in 2012. On each of the days, the emissions appeared to originate from the same tank. Infrared videos indicate that all of the emissions >3.0 g/s occurred during the time period that a thief hatch on a condensate tank was open (SI Video S4, Video S5, and Video S6). On the last day the site was measured, the thief hatch was closed and the measured emissions seemed to originate from a pressure relief device and were <3.0 g/s (SI Video S7).

Another potential cause of variation in emissions levels is the variability in plume capture. Depending on meteorological conditions, the plume measured can include all of the sources on the pad or only some of the sources (Figure 2). Measurements were made at Site H on 3 days in 2012 and 1 day in 2013 (four and two independent emission measurements, respectively). The higher emissions observed were only present on one of the days in 2012 and originated from the tank on the north side of the pad (SI Video S2), whereas the smaller emissions seemed to originate from the southern edge of the pad (SI Video S3).

Comparisons of CH_4 Emissions by Basin and with Direct Measurement Studies. A total of 318 OTM 33A measurements that met the data quality criteria were collected. Of these measurements, 31 were excluded from the analysis because the measured emissions either did not originate from routine pad operations (e.g., evidence of active pad maintenance, pipeline leaks, gas processing plants, etc.) or no current production data were available, resulting in a total of 210 unique sites. The sites were classified into gas or oil pads based on the TX Railroad Commission definition of a gas well[26] (>100 Mscf of gas per barrel of hydrocarbon liquids). Gas pads constituted 93%, 2%, 75%, and 84% of the sites measured in the Barnett, DJ, Eagle Ford, and Pinedale basins, respectively. Methane emissions were averaged by site and month, resulting in a total of 228 combinations of emission and production values. Due to the small sample size in the Eagle Ford (n = 4), these measurements were excluded from the basin comparison (Figure 3). CH_4 emissions were log-normally distributed with geometric means and 95% confidence intervals (CIs) of 0.33 (0.23, 0.48), 0.14 (0.11, 0.19), and 0.59 (0.47, 0.74) g/s in the Barnett, Denver-Julesburg, and Pinedale basins, respectively. Emissions by basin were compared using a Kruskal–Wallis one-way analysis of variance test and pairwise Wilcoxson rank-sum tests and were found to be significantly different (p < 0.05). The differences in emissions between basins are likely a result of a combination of factors, including but not limited to variations in gas and oil production, emissions control devices, and natural gas and oil composition.

The OTM 33A measurements were compared with the results of the direct measurement studies of routine pad operations conducted by ERG[15] and Allen et al.[16] (Figure 3). The studies encompass a range of pads that vary with respect to oil and gas composition, production levels, amount and type of production equipment, age, and emission control measures, resulting in a broad distribution of emissions. The mean of the CH_4 emissions measured using OTM 33A in the Barnett Shale, 0.33 (0.23, 0.48) g/s, is more than twice the mean of the emissions measured by ERG[14] 0.14 (0.11. 0.18) g/s. Nevertheless, the interquartile range of the OTM 33A measurements in the Barnett falls within the interquartile range of the ERG emissions estimates despite the differences in the measurement methods and the bias toward higher-emitting sites in the OTM 33A measurements.

Both onsite and remote measurement techniques can provide important information on emissions. Whereas direct measurements can accurately quantify component-level emissions, they are less amenable to locating and assessing malfunction-related or large short-term emissions such as condensate tank flashing. The measurements by Allen et al.[16] were limited primarily to equipment leaks, pneumatic controllers, and chemical injection pumps. Condensate tank emissions were measured at some sites but rarely could all of the emission points be accessed. In the ERG study,[15] due to

Figure 2. Map of repeated measurements at sites H and I. The directions of the colored arrows indicate mean wind directions and the locations indicate the locations of the mobile platform during the measurement.

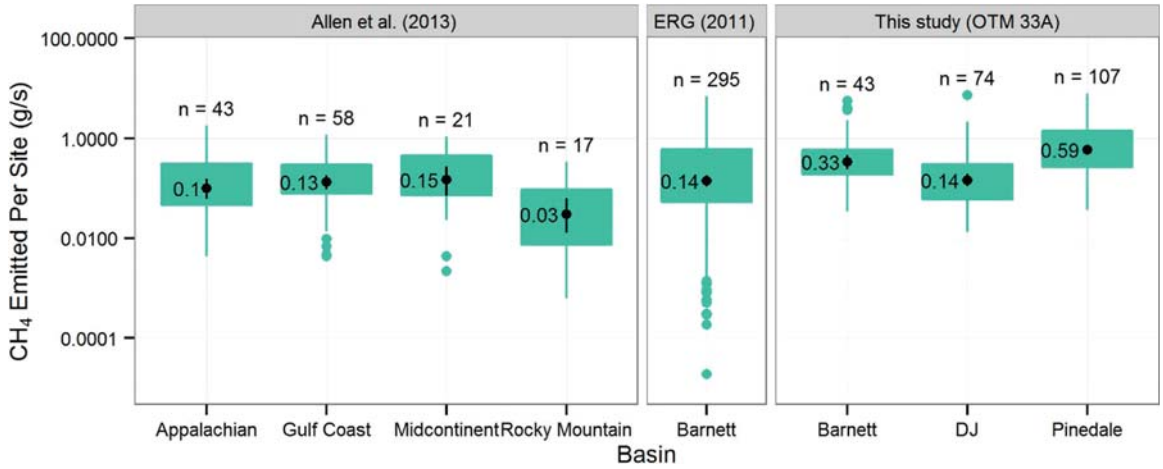


Figure 3. Comparison of measured CH_4 emissions per pad (g/s) from Allen et al.,[16] ERG,[15] and OTM 33A by basin. Boxes represent the 1st and 3rd quartiles of the data, while whiskers extend to the largest measurement that is within 1.5 times the interquartile range (IQR). Means and 95% CIs are shown in black and were calculated using a nonparametric bootstrap.

lack of condensate production, flash emissions were not represented. Although both studies measured fugitive component leaks, neither identified or measured potentially larger maintenance-related emissions (e.g., open thief hatch or failed pressure relief value). In contrast, OTM 33A measurements generally represent an integrated plume including all potential sources on a pad. Supporting infrared camera footage from the OTM 33A studies indicated that emissions often originate from condensate storage tanks which have previously been shown to comprise a significant source[6,5] (SI Supplemental B). OTM 33A is also more likely to capture malfunction-related CH_4 releases than direct measurement methods because of its mobile and off-site measurement capabilities.

However, the remote nature of the OTM 33A method and its application in these studies to only sites with downwind average in-plume concentrations greater than 0.1 ppm result in an effective lower sampling limit of approximately 0.010 g/s, compared with <0.001 g/s limits for the on-site measurement techniques (Figure 4a). As a result, the OTM 33A measurements only represent the upper end of the distribution in this comparison (Figure 4b).

Comparison of Measurements with Production Values. CH_4 emissions from the direct measurement studies and OTM 33A were compared to monthly gas production using a linear regression on the log transformed data (Figure 5). Sites with gas production <1 Mscf/day or CH_4 emissions <0.0005 g/s were excluded from the analysis (five sites in the ERG study[15]). Gas production values explained more of the variation in the OTM 33A measurements than the measurements from the on-site studies, although variation in gas production still accounted for only 8.3% of the total variation in emissions (R^2 = 0.083) (Figure 5).

The OTM 33A CH_4 emission estimates were also compared with hydrocarbon liquids and water production and the (arithmetic) mean age of active permitted wells on the site using Pearson correlation coefficients (Table 1) and a multivariate linear regression.

Approximately 23% and 15% of the pads measured using OTM 33A reported no hydrocarbon liquids or water production, respectively. To use these pads in the log-transformed model, pads with no reported oil or water production were assigned 0.01 bbl/day. Several values were

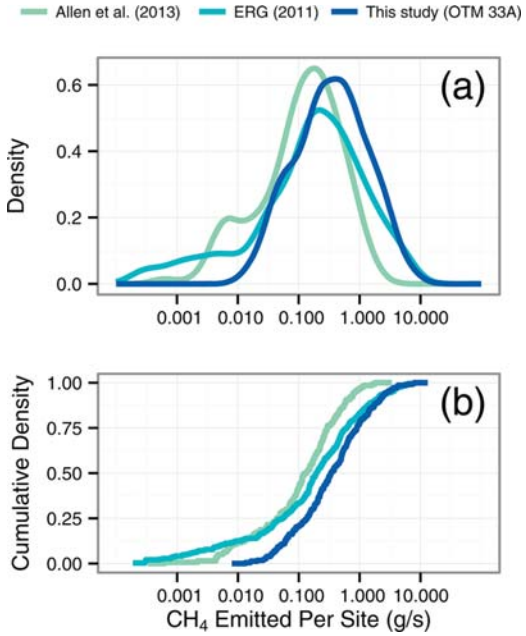


Figure 4. Density (a) and cumulative density (b) of measurements of CH_4 emission rates (g/s) from this study (OTM 33A), Allen et al.,[16] and ERG.[15] Note the logarithmic *x*-axis.

tested and the choice of this value did not significantly affect the results. When considering the correlation between production and emissions individually, CH_4 emissions were most strongly correlated with gas production (R = 0.29). CH_4 emissions were also positively correlated with water production, negatively correlated with mean age, and not correlated with hydrocarbon liquids production (Table 1).

A multivariate linear regression was conducted to determine the effect of gas and hydrocarbon liquids production and age of the well on CH_4 emissions simultaneously. Water production was not included in the model because it was so highly correlated with gas production (R > 0.7) that the effects could not be separated. The following model was used:

$$\log(CH_4) = \beta_1 \log(\text{gas}) + \beta_2 \log(\text{oil}) + \beta_3 \text{age} \quad (1)$$

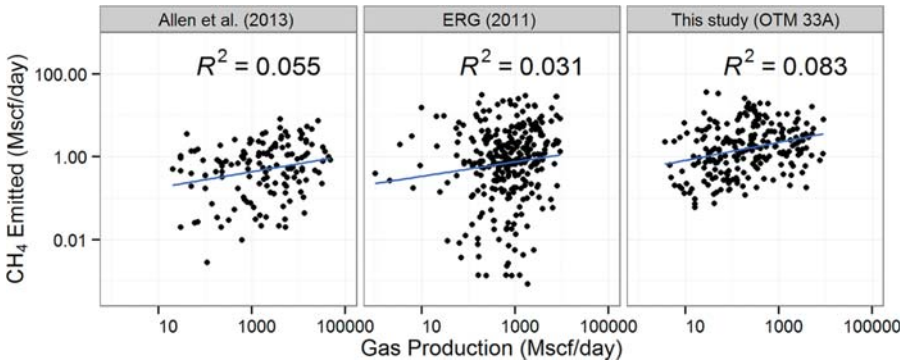


Figure 5. CH_4 emissions (Mscf/day) versus reported monthly gas production (Mscf/day). Blue lines represent the linear regression lines.

Table 1. Pearson Correlation Coefficients (R) of Emissions and Production

	CH_4 emissions (Mscf/day)	gas production (Mscf/day)	hydrocarbon liquids production (bbl/day)	water production (bbl/day)
CH_4 emissions (Mscf/day)	1.00			
gas production (Mscf/day)	0.29	1.00		
hydrocarbon liquids production (bbl/day)	−0.01	0.44	1.00	
water production (bbl/day)	0.22	0.77	0.40	1.00
mean age (years)	−0.20	−0.59	−0.34	−0.57

where CH_4 represents measured emissions in g/s, gas is total reported production in Mscf/day, oil is total reported hydrocarbon liquids production in bbl/day, and age is the mean age of the wells in years. Age was not significantly correlated with CH_4 emissions, while gas production was significantly positively correlated, and oil production was significantly negatively correlated (SI Table S2). The negative correlation with oil production is consistent across the basins (SI Figure S1). This negative correlation with oil production is likely due to the lower fraction of CH_4 in wet gas compared to dry gas. Furthermore, emissions from condensate tanks, which are more prevalent in wet gas areas, typically contain a lower fraction of CH_4 and higher fraction of heavier hydrocarbons such as VOCs when compared with produced gas.[6] The inclusion of hydrocarbon liquids and age in the model did not explain much more of the variation in emissions resulting in an adjusted R^2 of only 0.096, in contrast to an R^2 of 0.083 when only gas production was included (Figure 5).

Other important sources of variation not accounted for in this analysis include emissions controls and equipment present on the pads. Further uncertainty is introduced by the production data: daily or hourly production levels may not be consistent with monthly production.

Although the OTM 33A CH_4 emissions data include episodic features (e.g., flash emissions), it is instructive to compare emission rates as a percent of production with the measurements by Allen et al.[16] and ERG.[15] The differences between the CH_4 emissions estimates of the three studies are amplified when emissions are considered as a percentage of total production rather than in mass emission rate (SI Figure S2). For the sites measured using OTM 33A, approximately 0.72 (0.44, 1.17)%, 1.36 (0.97, 1.95) %, and 0.58 (0.39, 0.86) % of production was emitted on average (with 95% CI) in the Barnett, DJ, and Pinedale basins, respectively, compared with 0.11 (0.09, 0.16)% of production measured by ERG[15] in the Barnett shale and 0.01 (0.01, 0.01) % and 0.09 (0.04, 0.20)% measured by Allen et al.[16] in the Appalachian and Rocky Mountain basins, respectively (SI Figure S2). As evidenced in the statistical analysis, differences in production rate explain only a fraction of the variation in emissions. The percentages from this study only represent emissions from routine well pad operations and thus cannot be directly compared to other estimates of total CH_4 emitted as a percent of production such as those by Brandt et al.[5] that include emissions from many other processes.

Mean gas production at the OTM 33A sites was significantly lower than mean gas production at the sites measured in the direct measurement studies (SI Figure S4). Gas production at the OTM 33A sites ranged from 3.7 (Mscf/day) to 9021 (Mscf/day) with 37% of the sites producing <100 Mscf/day. In contrast, Allen et al.[16] reported a gas production range of 20 to 47 690 (Mscf/day) with only 10% of the sites producing <100 Mscf/day and with approximately 20% of the measured sites producing >10,000 Mscf/day. The gas production values of the ERG[15] sites ranged from 0.06 to 9085 Mscf/day in the Barnett with 10% of the sites producing <100 Mscf/day (SI Figure S4). The OTM 33A results indicate that sites with very low gas and oil production can emit a much greater fraction of the gas produced than sites with higher production levels. Maintenance issues (e.g., fugitive leaks, open or leaking thief hatches, failed pressure relief devices, malfunctioning separator dump valves) could be more prevalent at smaller older production sites than at higher producing sites that are potentially better maintained and may have fundamentally different engineering designs (e.g., use of buffer tanks to suppress flash emissions). Furthermore, many of the fugitive processes can emit at levels that are not linearly associated with production rates as is evidenced by the lack of correlation between emissions and production and the finding by Allen et al.[16] that equipment leaks are underestimated by the 2011 EPA national inventory.

In summary, the OTM 33A mobile inspection method can be used to complement direct measurement techniques and expand our knowledge of the upper range of the distribution of CH_4 emissions. OTM 33A was successfully applied to quantify CH_4 emissions at 210 oil and gas well pads with an accuracy of ±60% determined by controlled release tests. Well pad emissions were log-normally distributed and differed significantly by basin with geometric means ranging from 0.14 g/s in

the Denver-Julesburg to 0.59 g/s in the Pinedale basin. Repeat measurements at 9 sites indicated consistent low emission rates at seven sites and highly variable emissions at two sites, one a documented malfunction. The production rates accounted for approximately 10% of the variation in sampled emission rates in a multivariate linear regression on age, hydrocarbon liquid and gas production. Normalizing emissions by gas production amplified the differences between the remote and onsite measurements. Compared to the direct measurements in the Barnett, the mean of the remote measurements was approximately twice as large in terms of mass emissions rate, but approximately seven times as large when considered as a percentage of production, indicating that sites with lower production levels can emit a much greater percentage of production. Infrared camera videos indicate that emission rates may be strongly affected by stochastic variables. In particular, equipment malfunctions or operator error may cause emission rates to increase substantially compared to routine operating conditions. Accurately estimating site emissions on a regional scale likely will require determining the average magnitude and frequency of these stochastic events.

■ ASSOCIATED CONTENT

Ⓢ Supporting Information

Supplemental figures, tables, and IR videos are supplied. This material is available free of charge via the Internet at http://pubs.acs.org.

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Notes

The authors declare no competing financial interest.

[#]On Oak Ridge Institute of Science and Education Fellowship.

■ ACKNOWLEDGMENTS

We thank Shahrooz Amin and Mark Modrak with ARCADIS, Inc., for field and data analysis support for this project. We would like to thank EPA colleagues Bill Mitchell, Adam Eisele, Mike Miller, Jason DeWees, Robin Segall, and Ken Garing and his team for ongoing support in development of OTM 33. Special thanks to Eric Crosson, Chris Rella, and Tracy Tsai with Picarro for ongoing collaboration on mobile measurements. Primary funding for this effort was provided by U.S. EPA ORD's Air, Climate, and Energy (ACE) and Regional Applied Research Effort (RARE) programs. Funding for the Environmental Defense Fund's methane research series, including this work, is provided for by Fiona and Stan Druckenmiller, Heising-Simons Foundation, Bill and Susan Oberndorf, Betsy and Sam Reeves, Robertson Foundation, Alfred P. Sloan Foundation, TomKat Charitable Trust, and the Walton Family Foundation. The views expressed in this article are those of the authors and do not necessarily represent the views or policies of the U.S. Environmental Protection Agency.

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Field Measurements of Fugitive Emissions from Equipment and Well Casings in Australian Coal Seam Gas Production Facilities

Report to the Department of the Environment

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June 2014

Citation

Day, S., Dell'Amico, Fry, R., Javanmard Tousi, H., (2014). Field Measurements of Fugitive Emissions from Equipment and Well Casings in Australian Coal Seam Gas Production Facilities. CSIRO, Australia.

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Acknowledgements

We gratefully acknowledge the CSIRO Energy Flagship and Department of the Environment for providing financial support for this project. The project would not have been possible without the cooperation of the CSG industry and the numerous company staff who provided assistance and advice. In particular we would like to thank Sally Oelerich, Tom Lawler and Aaron Clifton of AGL, Jenny Bright and Ben McMahon of Arrow Energy, Graeme Starke of QGC, Liz Beavis, Michael Boyle, Mark Rider and Dan O'Sullivan of Origin Energy, and Anshul Jain, Michael Roberts, and Rob Dunsmuir of Santos.

Executive Summary

The Australian coal seam gas (CSG) industry has developed rapidly over the last decade and as several liquefied natural gas (LNG) plants currently under construction in Queensland are completed, gas production will increase significantly over the next few years. Fugitive emissions of methane from gas production and processing have the potential to diminish the greenhouse benefits of CSG utilisation compared to other fossil fuels but at present the extent of fugitive emissions from the CSG industry and unconventional gas production more generally is not well understood. Recent reports from the United States have suggested that fugitive emissions from unconventional gas production, especially shale and tight gas, are much higher than previously estimated. However, because of significant differences in production methods and other factors, it is unlikely that emission estimates from U.S. shale and tight gas production are indicative of emissions from Australian CSG operations. To provide quantitative information on emissions from CSG operations, CSIRO and the federal Department of the Environment initiated a project to measure emissions from a range of production wells in Queensland and NSW.

Methane emissions were measured at 43 CSG wells – six in NSW and 37 in Queensland. Measurements were made by downwind traverses of well pads using a vehicle fitted with a methane analyser to determine total emissions from each pad. In addition, a series of measurements were made on each pad to locate sources and quantify emission rates.

Of the 43 wells examined, only three showed no emissions. These were two plugged and abandoned wells and one suspended well that had been disconnected from the gas gathering system. The remainder had some level of emission but generally the emission rates were very low, especially when compared to the volume of gas produced from the wells. The principal methane emission sources were found to be:

- venting and operation of gas-powered pneumatic devices,
- equipment leaks and
- exhaust from gas-fuelled engines used to power water pumps.

The median methane total emission rate (from all sources) for the 43 wells was approximately 0.6 g min^{-1}, and the mean about 3.2 g min^{-1}. Thirty seven wells had total emissions less than 3 g CH_4 min^{-1} and 19 less than 0.5 g min^{-1}. There were however, a number of instances where much higher emission rates were found. The highest emission rate of 44 g min^{-1} was from a vent on a water line at one well although this represented a very minor proportion of gas production. These emission rates are very much lower than those that have been reported for U.S. unconventional gas production.

Gas operated pneumatic devices were installed at some well sites and were occasionally found to be emitting small amounts of methane. These emissions were small (mean emissions rate of 0.12 g min^{-1}) and may reduce even further as gas operated pneumatic systems are replaced by air or electrically operated devices.

Equipment leaks were found on 35 wells with emission rates ranging from less than 1 mg min^{-1} up to about 28 g min^{-1}. The median and mean emission rates from these wells were 0.02 g min^{-1} and 1.6 g min^{-1}, which correspond to emission factors of about 0.1 kg CO_2-e t^{-1} and 2.4 kg CO_2-e t^{-1}, respectively. This range is consistent with the current emission factor of 1.2 kg CO_2-e t^{-1} commonly used throughout the CSG industry to account for equipment leaks for the purposes of reporting emissions under the National Greenhouse and Energy Reporting legislation.

Several of the larger equipment leaks were found at seals on water pump shafts on some wells. However, once identified, well maintenance staff were able to repair some of these leaks on site, which effectively eliminated methane emissions.

Fifteen of the well sites had gas fuelled engines operating at the time measurements were made. The exhaust from most of these engines was found to be contributing to the well site emissions, in several cases

comprising the bulk of methane emissions. From a greenhouse gas accounting perspective, methane in exhaust is not considered to be a fugitive emission but is counted as a combustion emission.

During the field measurements, no evidence of leakage of methane around the outside of well casings was found at any of the wells included in this sample.

Although the well pad emissions were low, a separate, larger source of methane was found on a gas relief vent on a water gathering installation close to one of the wells examined during this study. An indicative estimate of the emission rate from this vent suggested that the source was at least three times higher than the largest well pad emission rate. Similar installations are widespread through the Queensland gas regions and hence further examination is needed to determine the extent of this potential emission source.

The results obtained in this study represent the first quantitative measurements of fugitive emissions from the Australian CSG industry; however, there are a number of areas that require further investigation. Firstly, the number of wells examined was only a very small proportion of the total number of wells in operation. Moreover, many more wells are likely to be drilled over the next few years. Consequently the small sample examined during this study may not be truly representative of the total well population. It is also apparent that emissions may vary over time, for instance due to repair and maintenance activities. To fully characterise emissions, a larger sample size would be required and measurements would need to be made over an extended period to determine temporal variation.

In addition to wells, there are many other potential emission points throughout the gas production and distribution chain that were not examined in this study. These include well completion activities, gas compression plants, water treatment facilities, pipelines and downstream operations including LNG facilities. Emissions from some of these sources are often estimated for reporting purposes using methodology based on emission factors largely derived from the U.S. gas industry. However, reliable measurements on Australian facilities are yet to be made and the uncertainty associated with some of these estimates remains high.

1 Introduction

Coal seam gas (CSG) production is a major and rapidly expanding industry in Australia. During 2011-2012, Australian CSG production was around 247 PJ, which represented about 12 % of total gas production in Australia (BREE, 2013). Since then, production in Queensland alone has increased to more than 264 PJ in 2012-2013 (DNRM, 2014) with production likely to increase even further as several liquefied natural gas plants under construction come on stream. Most Australian CSG is currently produced in Queensland with only one operational project in NSW; however, there are a number of other projects planned for NSW at various stages of approval.

One of the key drivers of increased demand for gas is that greenhouse gas emissions from gas utilisation are usually lower than other fossil fuels (Day et al., 2012). However, because of the much higher global warming potential of methane compared to CO_2, even relatively small proportions of fugitive methane released during the production, processing and distribution of natural gas can reduce this advantage relative to other fuels (e.g. Wigley, 2010; Alvarez et al., 2012).

In the natural gas industry, fugitive emissions are considered to include all greenhouse gas emissions from exploration, production, processing, transport and distribution of natural gas, except those from fuel combustion (IPCC, 2006). However certain combustion processes like flaring and waste gas incineration are also counted as fugitive emissions.

At present the level of fugitive emissions from the Australian CSG industry is not well defined, although individual companies estimate and report their annual emissions under the requirements of the National Greenhouse and Energy Reporting Act 2007 (NGER, see Section 2). These data are used for compiling the Australian National Greenhouse Gas Inventory which currently estimates fugitive emissions from the Australian oil and gas industry to be around 12 Mt CO_2-e per annum (DIICCSRTE, 2013a). About 60 % of these emissions are attributed to venting and flaring, which are in principle amenable to direct measurement; hence the uncertainty on this component may be relatively low. However, other sources such as equipment leaks are frequently difficult to measure so are usually estimated by methodology characterised by very high uncertainty. Despite significant differences in production methods, the national inventory does not at present distinguish between conventional gas production and unconventional sources like shale gas and CSG.

In 2012, the CSIRO reviewed the available scientific and technical literature to assess the current state of knowledge relating to fugitive emissions from unconventional gas production, especially for CSG production in Australia (Day et al., 2012). Most of the information in the public domain at the time was concerned with shale and tight gas production in the United States with virtually none specific to CSG. Up until then, only one study based on actual measurements had been published (Pétron et al., 2012). This group measured methane emissions in the Denver-Julesburg Basin in Colorado and depending on the method used, estimated that the emission rate from the gas field was equivalent to 1.7 to 7.7 % of the gas produced in the region.

Since 2012, several other studies, also from the United States, have been published. Karion et al. (2013) conducted an airborne survey of ambient methane in an unconventional gas field in the Uintah Basin in Utah in the United States. The Karion et al. study yielded emission estimates of between about 6 and almost 12 % of gas production of the region. In a detailed examination of atmospheric methane data from airborne and fixed monitoring stations, Miller et al. (2013) determined the spatial distribution of methane emissions throughout the United States. This study considered all sources of anthropogenic methane emissions, including fugitive emissions from oil and gas production. For the Texas/Oklahoma region emissions from oil and gas production were estimated to be 3.7 ± 2.0 Tg C y^{-1}, which is 4.9 ± 2.6 times higher than the current estimate of 0.75 Tg C y^{-1} in the European Commission's Emissions Database for Global Atmospheric Research (EDGAR).

Both the Miller et al. (2013) and Karion et al. (2013) studies used top-down methodology and did not attempt to determine the specific sources of the methane emissions. Pétron et al. (2012) also used top-down methods which yielded the higher estimates (i.e. ~7.7 % of production) although the bottom-up methodology used by that group gave much lower emission estimates (1.7 %). A bottom-up approach was used by Allen et al. (2013) who examined emissions at the facility level to determine both the rate and route of methane emission. In that study, methane emissions were measured at 190 onshore natural gas sites within the United States, which included 489 production wells (all of which had been hydraulically fractured), 27 well completion flowbacks, nine well unloadings, and four well workovers. One of the key findings of this work was that the measured emissions were generally comparable to the most recent USEPA estimates of emissions from the sources examined, although the relative proportion of emissions from individual categories differed somewhat. For example, emissions from pneumatic devices were significantly higher than current estimates while emissions from well completions were much lower than estimates in the U.S. inventory. Overall, the emissions estimated from the unconventional gas industry corresponded to about 0.42 % of production.

This bottom-up estimate contrasts with the much higher top-down estimates discussed above. The lower emission rate estimated by Allen et al. (2013) may be explained in part by the fact that only production facilities were considered. Emissions from downstream processing, transport and distribution were not included so any emissions from these facilities would be expected to increase this proportion. Another reason for the discrepancy between bottom-up and top-down estimates has been proposed by Brandt et al. (2014) who suggested that a large proportion of emissions may be due to a small number of 'super emitters'. If true, facility level bottom-up measurements may sometimes miss these large emission sources. In addition to gas production facilities, other sources may be contributing to overall emissions, which are not captured by the bottom-up methods. Tait et al. (2013), for example, proposed that drilling and associated activity may induce fracturing of overlying strata thus providing pathways for methane to reach the surface and escape to the atmosphere. Such landscape-scale emissions would be detected by many top-down methods but may be difficult to measure using the bottom-up methodology applied by Allen et al. (2013). However, the Tait et al. (2013) model was based on ambient radon measurements; methane emission rates were not measured so this emission route remains speculative at this stage. Other possible emission sources that could account for the apparent discrepancy between the reported top-down and bottom-up methods are geological sources such as seeps that are often associated with oil and gas fields (Klusman, 1993) or abandoned boreholes (Etiope et al., 2013; Day et al., 2013).

In Australia, limited investigations into fugitive methane emissions from CSG production have been undertaken over the last couple of years. In an initial study that was widely reported, Santos and Maher (2012) surveyed a CSG production region near Tara in Queensland using an instrumented vehicle to measure the spatial distribution of ambient methane concentrations. They measured elevated methane concentrations within the gas field that they suggested may be indicative of fugitive methane release from production activities. More recently, a study of ambient methane levels in the vicinity of CSG production facilities south of Sydney was reported (Pacific Environment Limited, 2014). This study also found elevated methane concentrations near CSG facilities although they concluded that on average, ambient methane concentrations within the gas field were comparable to those in a nearby urban area. However, neither study attempted to measure emission flux and in any case, the presence of other potential methane sources such as cattle feedlots, abandoned boreholes and landfill sites complicated the interpretation of the results. Consequently attempts to attribute sources based on these results remain inconclusive.

Despite the level of recent activity aimed at quantifying emissions from unconventional gas production, the situation remains unclear. The Australian studies reported to date only considered ambient methane concentrations near gas production sites and provide no information on emission flux. While the U.S. studies measured emission rates, widely varying estimates were reported. Moreover, they were concerned with shale and tight gas operations, which are unlikely to be indicative of emissions from Australian CSG production facilities. Due to the lack of quantitative emission data specific to Australian operations, the CSIRO review recommended, among other things, that a series of measurements at CSG production facilities was required to better understand the actual level of fugitive emissions from the Australian CSG

industry (Day et al., 2012). A similar recommendation for emissions measurements was made by Saddler (2012) when reviewing methodology for estimating emissions from CSG production.

As a result of these recommendations, CSIRO initiated a project with the principal aims of (1) developing atmospheric top-down methodology for monitoring and quantifying methane fluxes from CSG production facilities and (2) measuring methane emission fluxes from operational CSG production sites. Shortly after this project commenced, the federal Department of the Environment (then the Department of Climate Change and Energy Efficiency) requested that CSIRO to extend the scope of the field measurements to include an investigation of gas leakage from well casings and equipment located on individual well pads.

In this report we present the results of field measurements made at well sites throughout NSW and Queensland. The specific objectives of these measurements were to:

- quantify methane emissions from individual well pads,
- identify the primary routes of these emissions,
- measure leak rates from individual items of equipment located on well pads and
- determine whether or not methane was leaking from around the outside of well casings and if so, measure the leakage rate.

While wells represent a major segment of the CSG production infrastructure, it is important to note that there are many other components downstream of the wells which have the potential to release greenhouse gases. These include processing and compression plants, water treatment facilities, gas gathering networks, high pressure pipelines and several LNG production facilities currently under construction near Gladstone. In the study reported here, we have only examined emissions from a small sample of CSG wells; none of the other downstream infrastructure has been considered at this stage. However, the ongoing CSIRO research into atmospheric top-down method methodology is aimed at developing techniques for monitoring emissions across the CSG industry more broadly.

2 National Greenhouse Gas Reporting Practices

Before discussing the experimental results of the field measurements it is instructive to consider the methodology currently used to estimate greenhouse gas emissions from CSG wells.

Australian CSG gas producers (along with conventional gas operators) are required to estimate and report their annual greenhouse emissions in accordance with the National Greenhouse and Energy Reporting Act 2007 using methodology prescribed in the National Greenhouse and Energy Reporting (Measurement) Determination 2008. The scope of the Act covers all sectors of the gas industry i.e. production and processing, transmission and distribution, and includes emissions from fuel combustion (e.g. stationary engines at well sites and compression plants) and fugitive emissions (leaks from equipment, venting and flaring).

According to the definition used in the Determination, fugitive emissions associated with natural gas production and processing comprise:

- Emissions from venting and flaring
    - the venting of natural gas
    - the venting of waste gas and vapour streams at facilities that are constituted by natural gas production or processing
    - the flaring of natural gas, waste gas and waste vapour streams at those facilities
- Emissions other than venting and flaring which include
    - a gas wellhead through to the inlet of gas processing plants
    - a gas wellhead through to the tie-in points on gas transmission systems, if processing of natural gas is not required
    - gas processing plants
    - well servicing
    - gas gathering
    - gas processing and associated waste water disposal and acid gas disposal activities

The Determination specifies methodology for estimating emissions from all of these sources; the 'Methods' are broadly classified into four generic categories of varying complexity, which are briefly described below.

- Method 1 is the simplest approach and relies on activity data and an emission factor for the process. The emission factors used in Method 1 are generic and are usually specified in the NGER Determination.
- Method 2 is more specific and uses emission factors based on more detailed data.
- Method 3 is very similar to Method 2 except that the methods are based on internationally accepted standards.
- Method 4 is the direct measurement of emissions.

Some emissions can be directly measured (i.e. Method 4) but often emissions cannot be readily measured so instead, simpler methodology based on the concept of emission factors is used.

Emission factors are average emission rates of a particular gas (i.e. methane but also CO_2 and N_2O if applicable) from a given source. Emissions, *E*, are calculated by multiplying the emission factor, *EF*, by the activity of the process producing the emissions, *A* (Equation 2.1).

$$E = EF \times A \qquad \text{Equation 2.1}$$

Examples of activity are the amount of fuel consumed or the amount of gas produced.

This methodology can yield accurate emission estimates for processes such as fuel combustion where both the emission factor (which is based on the chemical composition of the fuel) and the activity data (i.e. consumption rate of fuel, which is often known to a high level of accuracy) can be well defined. However,

for some fugitive emissions sources such as equipment leaks, emission factors may be subject to very high uncertainty. For instance, the American Petroleum Institute's Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry which provides emission factors for calculating emissions from gas production and processing operations, estimates that uncertainties on some emission factors may be as much as 1000 % (API, 2009). One of the reasons for this high level of uncertainty is that emission factors are often based on very limited experimental data.

CSG well pads may release greenhouse gases from a range of sources, all of which are estimated for annual reporting purposes. These sources include fuel combustion in well site engines used to drive water pumps, and fugitive emissions from vents, gas operated pneumatic devices and leaks in equipment. Occasionally, during maintenance operations for example, gas may be flared and this too counts as a fugitive emission that is accounted for. Combustion emissions from engines or flaring are predominantly CO_2 although small amounts of methane (unburnt fuel) and N_2O (produced in the combustion process) may also be emitted. Most of the other non-combustion emissions are methane.

Some emissions from vents can be measured according to Method 4 but because of its simplicity, many CSG operators use the Method 1 approach for estimating most of the other greenhouse gas emissions from well pads. The methods are summarised in Table 2.1.

Table 2.1. Summary of NGER estimation methods for various well pad sources

Classification	Source	Method
Fuel Combustion	Exhaust emissions from well site engines	Emission factor to account for CO_2, CH_4 and N_2O emissions: 51.2 kg CO_2-e GJ^{-1} (CO_2) 0.1 kg CO_2-e GJ^{-1} (CH_4) 0.03 kg CO_2-e GJ^{-1} (N_2O)
Fugitive Emissions	Flare	Emissions factor to account for CO_2, CH_4 and N_2O emissions: 2.7 t CO_2-e t^{-1} (CO_2) 0.1 t CO_2-e t^{-1} (CH_4) 0.03 t CO_2-e t^{-1} (N_2O)
Fugitive Emissions	Equipment leaks	Emission factor of 1.2 kg CO_2-e t^{-1} gas produced
Fugitive Emissions	Gas driven pneumatic equipment	Emission factors specified in the API Compendium (API, 2009)
Fugitive Emissions	Cold process vents	In some cases these can be measured directly (i.e. Method 4). Otherwise estimated using emission factors in API Compendium.

Although most of the methods shown in Table 2.1 are based on the use of emission factors, the level of uncertainty associated with the estimates is quite variable. In the case of emission from engines, the uncertainty is likely to be relatively low provided the amount of fuel consumed is known accurately (which is usually the case). Similarly emissions from flaring can be estimated with reasonable accuracy if the gas

flow to the flare is measured. Emissions from vents are often measured using process instrumentation so these too should be known with a high degree of certainty. Emissions from equipment leaks, pneumatic equipment and vents estimated by emission factors, on the other hand, have higher levels of uncertainty. However, the overall uncertainty of emission inventories is also influenced by the relative contribution of various sources. Hence if a source with high uncertainty comprises only a small proportion of total emissions from a particular sector, the overall level of uncertainty is not greatly influenced by the minor component.

3 Experimental Methods

3.1 Selection of Wells

Five CSG companies provided access to wells in various gas fields throughout NSW and Queensland, which are summarised in Table 3.1. Each company usually provided CSIRO with a list of their wells from which CSIRO staff selected a subset of wells for examination. Because individual companies agreed to participate in the project at different times during the course of the project it was not possible to make a properly randomised selection of wells at the start of the project. Instead, wells were selected on an ad hoc basis in the order that companies agreed to participate. In addition, access to sites due to weather and agreements with landholders determined the selection of wells to some extent.

Factors considered when selecting wells included:

- The production region
- The age of the well, i.e. old to new
- The gas production rate, i.e. from low to high rates
- Whether or not the well had been hydraulically fractured
- The type of surface equipment installed at the well, i.e. pumped or free flowing.

Table 3.1. Participating CSG producers and the gas fields where emission measurements were made.

Company Name	Project Name	Basin	Locality
AGL Energy Limited	Camden	Sydney	MacArthur region, NSW
Arrow Energy Limited	Daandine	Surat	Dalby area, Qld
	Kogan North	Surat	Dalby area, Qld
	Tipton	Surat	Dalby area, Qld
Origin Energy Limited	Talinga	Surat	Chinchilla area, Qld
QGC Pty Limited	Bellevue	Surat	Chinchilla area, Qld
	Berwyndale	Surat	Chinchilla area, Qld
	Berwyndale South	Surat	Chinchilla area, Qld
	Codie	Surat	Chinchilla area, Qld
	Kenya	Surat	Chinchilla area, Qld
	Lauren	Surat	Chinchilla area, Qld
Santos Limited	Fairview	Bowen	Injune area, Qld
	Scotia	Bowen	Wandoan area, Qld

For the purpose of this report, we consider the well pad to be the (usually) fenced area around a well head that contains the surface equipment associated with gas production. This includes the well head, dewatering pump (if fitted), separator, pipework and associated valves and fittings. Also included are vents, (including those installed on water gathering system components on the well pad) and engines used to power dewatering pumps.

The 43 wells selected represent less than 1 % of the 5,000 CSG wells across Australia and therefore may not be representative of the total well population. Nevertheless, it provides a reasonable cross section of the industry covering a range of different producers and geographic locations within the main gas production regions. For comparison, a recent study of well emissions in the U.S. where emissions measurements were made at 489 wells represented only about 0.01 % of U.S. unconventional gas wells (Allen et al., 2013).

3.2 Methane Analysis System

Methane measurements were made using a Picarro Model 2301 Cavity Ring-down Spectrometer $CH_4/CO_2/H_2O$ analyser coupled with a Picarro Mobile Measurement Kit. The resolution of this analyser is < 1 ppbv CH_4 and has very low drift characteristics (Crosson, 2008) so that very small CH_4 perturbations can be reliably detected against the background concentration. Both instruments were mounted in a 19" rack in the rear of a 4WD vehicle (Figure 3.1).

Figure 3.1. Photographs of the field vehicle where the GPS antenna and sonic anemometer are visible on the top of the vehicle (left hand photograph). The methane analyser and a calibration gas cylinder are shown in the rear of the vehicle (right hand photograph).

The Mobile Kit included a GPS receiver and software that allows the spectrometer output to be processed and displayed in GIS software. A two-dimensional sonic anemometer (Climatronics Sonimometer) was also fitted for measuring local wind speed during plume traversing measurements (Section 3.3).

For mobile surveys, the spectrometer was operated continuously as the vehicle was driven. Air was sampled via a ¼" nylon tube from the front of the vehicle about 1 m above ground level. The normal flow rate of sample air to the spectrometer is approximately 100 mL min^{-1}; however, to minimise the lag time between air entering the inlet tube and reaching the analyser, an auxiliary pump in the Mobile Kit was used to increase the flow rate to about 5 L min^{-1}. When used for flux chamber measurements (Section 3.5), the auxiliary pump was bypassed using a three-way valve.

Initially, the instrument was configured to measure CH_4, CO_2 and H_2O simultaneously; however, the sampling rate in this mode was relatively slow with measurements made approximately every 3 s. To increase the spatial resolution during plume traverses, the sampling rate was increased to about 2 Hz by reconfiguring the analyser to measure CH_4 only.

The analyser was calibrated against a reference air sample containing 1.732 ppm CH_4 prepared by the CSIRO Marine and Atmospheric Research GASLAB (Francey et al., 2003). Additional standard gas mixtures of 10.2 and 103 ppm CH_4 in air (BOC Gases Australia) were used for multipoint calibrations.

Although the nominal range of the analyser is 0-20 ppm CH_4, we found that the instrument could reliably measure concentrations well in excess of this level. In one experiment, an Ecotech GasCal dilution system was used to generate gas flows with known CH_4 concentrations up to about 280 ppm. The results of this experiment are shown in Figure 3.2 where the analyser output is plotted against the actual methane concentration.

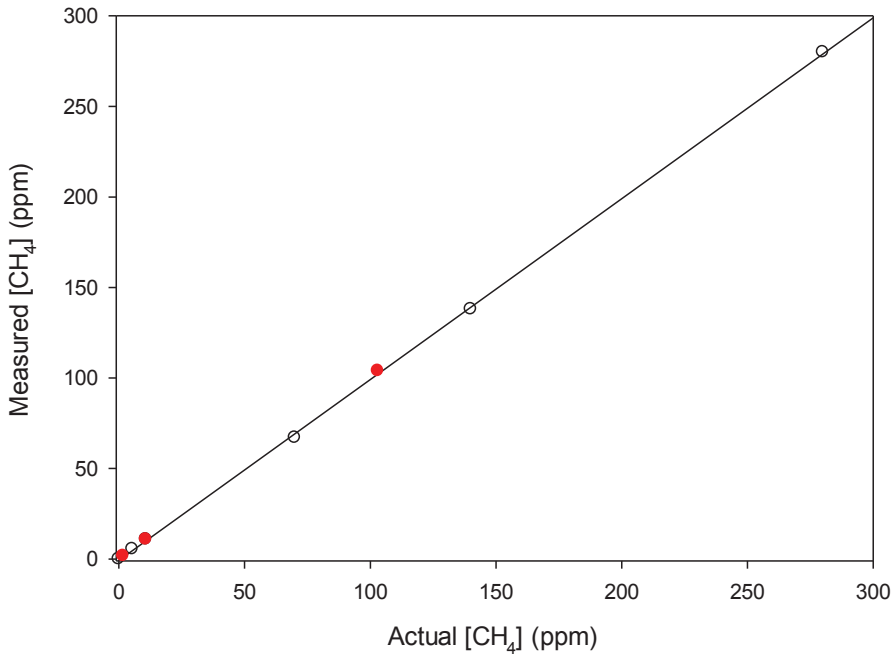

Figure 3.2. Calibration curves obtained for the methane analyser. Open circles correspond to points made using gas mixtures generated with a gas diluter. Red circles represent a multipoint calibration made using reference gases several months later.

The response of the instrument remained linear at least to 280 ppm CH_4. One of the routine multipoint calibration curves using the three reference gases made several months later (red markers) is also plotted to demonstrate the low drift characteristics of the instrument.

Multipoint calibrations were performed before and after each field campaign and single point calibration checks were made periodically in the field.

3.3 Plume Traverses

Methane emissions from well pads were estimated using a plume dispersion method. In this method, the CH_4 concentration profile in a plume originating from CH_4 emission sources on the pad is measured at some distance downwind of the pad by performing traverses across the plume. Since the plume comprises all CH_4 released from the pad, it yields total emissions from each pad. The technique is illustrated in Figure 3.3.

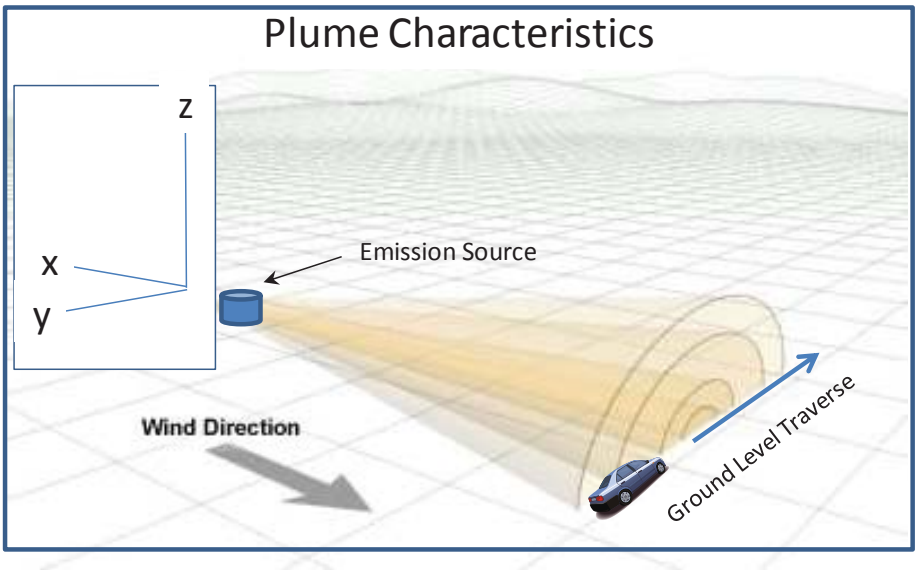

Figure 3.3. Schematic representation of the plume traversing experiments.

The field vehicle with the CH_4 analyser was driven 15 to 50 m downwind of each well to measure the ground level CH_4 concentration across each plume. The emission flux, *F*, over each traverse was estimated by integrating the CH_4 concentration enhancement (i.e. the measured concentration minus background CH_4 concentration), *c*, of the plume in the horizontal and vertical directions and multiplying by the average wind velocity, *u*, measured at each site (Equation 3.1). Background CH_4 concentrations were measured by performing upwind traverses of the well pad.

$$F = u \int_{-y}^{y} \int_{0}^{z} c(y,z)dydz \qquad \text{Equation 3.1}$$

Since the traverse measurements were made at ground level only, the vertical extent was estimated by reference to the Pasquill-Gifford curves of σ_z (i.e. the standard deviation of the distribution of CH_4 concentration in the vertical direction) as a function of downwind distance under given atmospheric turbulence conditions (Hanna et al., 1982). The vertical concentration profile of CH_4, within the plume was assumed to decrease from the ground level concentration with height according to a Gaussian distribution across the traverse plane. For each well, an average emission rate was determined from up to 10 traverses made over about a 20-minute period.

One of the primary sources of uncertainty with the plume traversing method is associated with determining the height of the plume because it must be estimated rather than measured. To assess the level of uncertainty in the plume traversing results, we performed a number of experiments where CH_4 was released from a cylinder of compressed gas at a known rate while traverses were made downwind of the source. The results of the traverses were then compared with the actual rate of CH_4 release. These controlled release measurements were made at a site near the CSIRO laboratories in Newcastle where there were no other sources of CH_4 present and to simulate field conditions, traverses were made between 15 and 50 m downwind of the controlled release point. The results of these experiments are discussed in Section 4.1.

3.4 Leak and Vent Testing

At each well site an initial survey for elevated CH_4 concentrations was made by performing vehicle traverses as described above to determine if CH_4 emissions were present. The presence of elevated CH_4 concentrations indicated some type of leak, venting or engine exhaust emission from the pump power pack. Where CH_4 was detected, more detailed examination of the facility was undertaken using a probe connected to the vehicle mounted CH_4 analyser to locate the source or sources of CH_4 (Figure 3.4). On

some occasions, leaks were located by spraying a leak detection solution (Snoop, Swagelok Company) onto individual components.

Figure 3.4. Locating equipment leaks at a CSG well pad.

When the source of the leak was identified, the leak rate was measured. During the first set of field measurements, leak rates were measured in accordance with the USEPA Protocol for Equipment Leak Emission Estimates (USEPA, 1995). In this procedure, the leaking component is enclosed in a plastic bag or sleeve and an air stream is passed through the bag at a known rate while the outlet stream is analysed for CH_4 concentration. Although this is a proven method for quantifying leak rates, it was found to be very slow and labour intensive. For later measurements (and the majority of the results reported here) we constructed a high-flow apparatus, similar in principle to the 'Hi-Flow' device reported by Kirchgessner et al. (1997). In this system, a high capacity fan attached to a 100 mm diameter flexible tube was used to provide an air stream around the leak point to entrain the leaking CH_4. A variable power supply was used to allow the fan speed to be varied up to a maximum flow rate of approximately 80 L s^{-1} (4.8 m^3 min^{-1}).

During leak tests, the inlet of the hose was held within about 150 mm of the apparent leak point while the CH_4 concentration in the outlet air stream was measured with the CH_4 analyser in the field vehicle. The leak rate, R_l, was calculated from the volumetric flow rate of the air stream, V, and the steady state CH_4 concentration, c, according to Equation 3.2

$$R_l = V \times c \qquad \text{Equation 3.2}$$

A schematic diagram of the apparatus is shown in Figure 3.5.

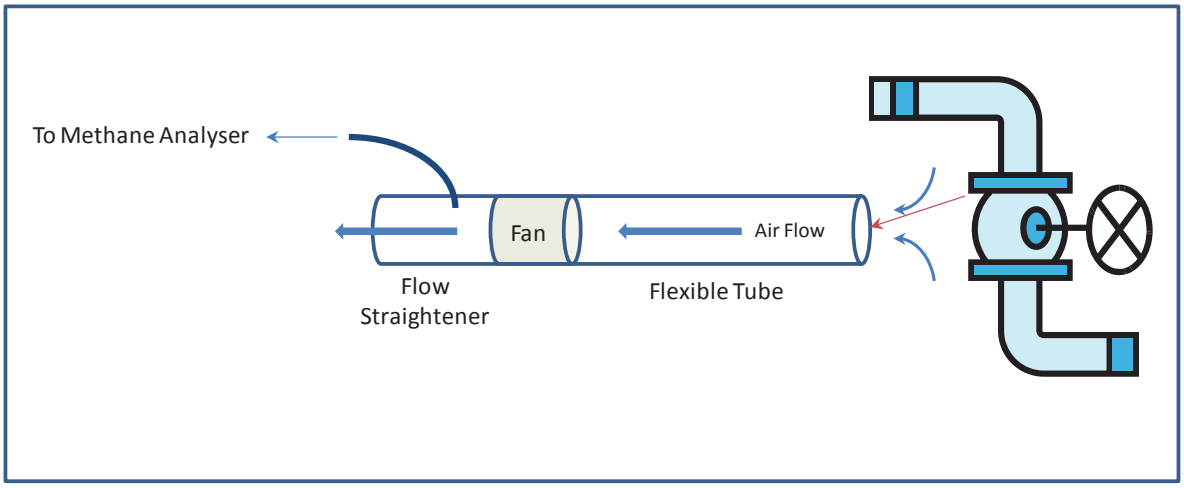

Figure 3.5. Schematic diagram of the leak testing apparatus. Methane leaking from a component (red arrow) is entrained in the airstream drawn into the tube by the fan.

Occasionally emission rates from some sources (e.g. vents and pneumatic devices) were amenable to a simple measurement technique where the exhaust point was sealed in a plastic bag of known volume and measuring the time required to fill the bag. In a few cases where the emission rate was reasonably constant, emission rates were measured by attaching a flow calibrator (DryCal DR2) to the emission outlet.

3.5 Surface Emissions

Measurements were made on the ground surface near well heads to determine if CH_4 was migrating around the outside of well casings or through casing walls. These measurements were made using a surface flux chamber, a technique frequently used to measure emission rates of soil gases. For these measurements, a plastic cylindrical chamber 37.5 cm in diameter and 40 cm high with a total volume of about 45 L and an area of coverage of 0.11 m^2 was placed on the ground at each sampling point. A small solar powered fan mounted in the chamber ensured that the sample within the chamber was well mixed during each experiment. The chamber was connected to the CH_4 analyser in the field vehicle via a ¼" nylon tube and the CH_4 concentration within the chamber, *C*, continuously measured over a period of several minutes. The flow rate of the sample stream from the flux chamber to the analyser was approximately 100 mL min^{-1}.

The CH_4 emission flux, *F*, was calculated according to Equation 3.3

$$F = \frac{V}{A} \frac{dC}{dt} \qquad \text{Equation 3.3}$$

where *V* is the volume of the chamber, *dC/dt* is the rate of change in the CH_4 concentration over time, *t*, and *A* is the area of surface covered by the chamber.

A schematic diagram of the chamber system is shown in Figure 3.6

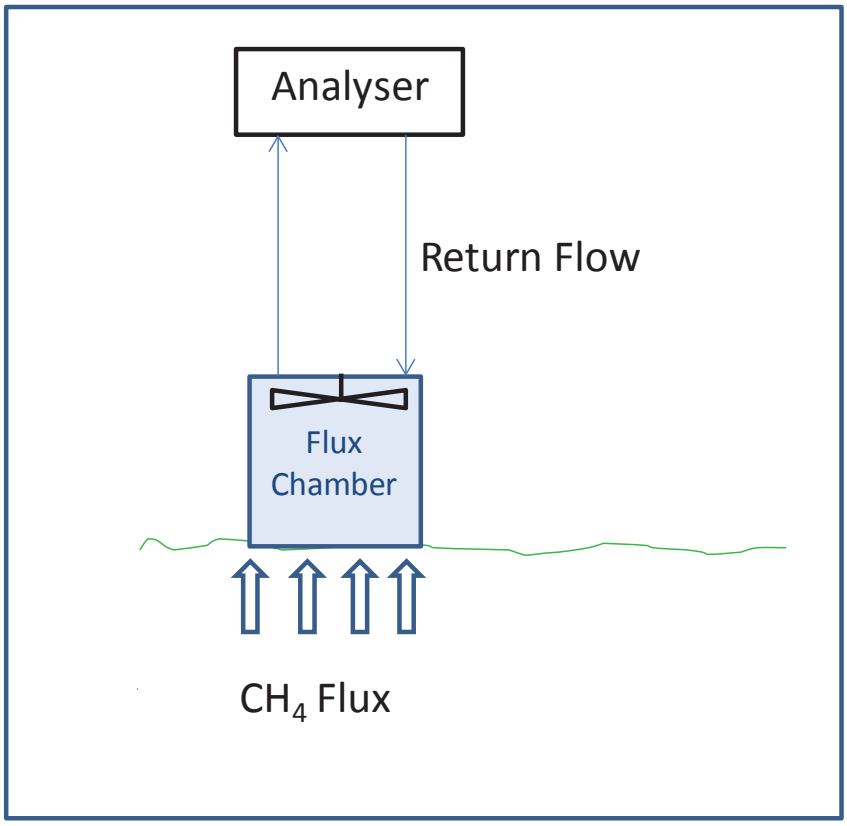

Figure 3.6. Schematic diagram of the flux chamber system used for well casing leak determinations

Typically, chamber measurements were made at four or more points within about 1 m of the well casing. In many cases, the chamber was placed adjacent to the casing, depending on access. Occasionally, additional measurements were made at distances up to about 20 m from the well head.

4 Results

4.1 Controlled Release

Controlled release experiments were conducted on several occasions with CH_4 release rates of between 0.7 and 0.8 g min^{-1} and traversing distances between 15 and 30 m downwind of the release point. Figure 4.1 shows the results of the controlled release experiments. The black markers represent the mean value determined by the traverses while the error bars show the minimum and maximum results determined over each set of traverses. The red markers represent the actual release rate.

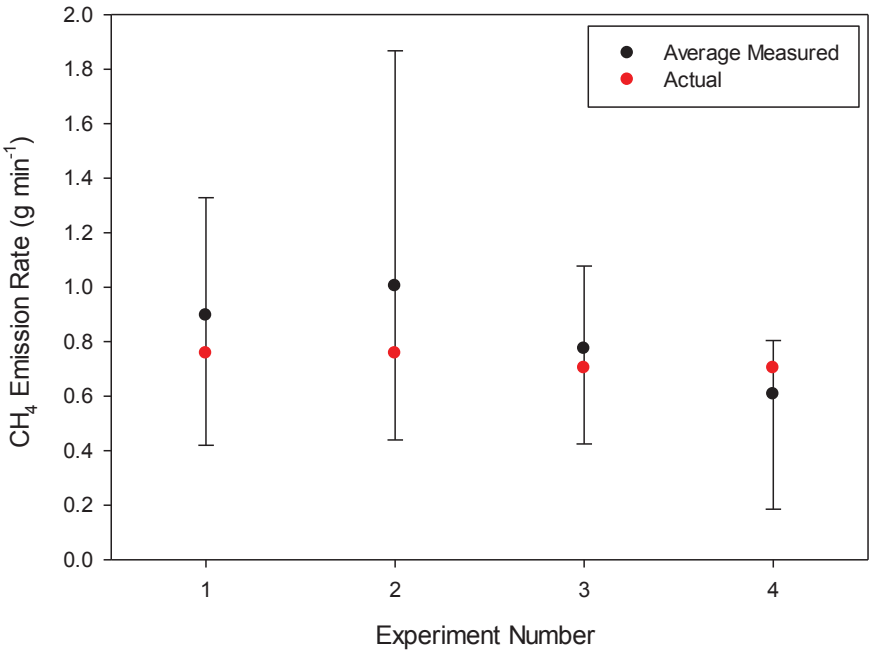

Figure 4.1. Summary of the controlled release experiments showing the CH_4 release rate determined by plume traversing and the actual release rate. Downwind distances were: Exp No 1 = 20 m; Exp No2 = 30 m; Exp No 3 = 15 m; Exp No 4 = 30 m. The error bars represent the range of emission rates measured during each set of six traverses.

Two initial experiments using a higher release rate of approximately 3.5 g min^{-1} and up to 50 m downwind overestimated the actual emission rate by about 100 and 60 % respectively. However, these experiments were based on only two traverses each so the poor agreement is unsurprising. The subsequent experiments (shown in Figure 4.1) were made using six traverses for each determination. In these cases, the agreement was much better with the emission rate determined by the average of the six runs being within about 30 % of the actual release rate, although there was significant variation among the individual traverses as shown by the error bars in Figure 4.1. Measurements made at CSG wells using the plume traversing method were therefore based on at least six and usually 10 or more individual traverses at each site.

4.2 Well Measurements

Emission measurements were made at 43 sites in NSW (six sites) and Queensland (37 sites). Most sites had only a single well on the pad, but there were a number where up to four well heads were located on an individual pad. The majority of wells were production wells, although 11 were not flowing at the time of the

measurements due to maintenance or other activities. Two of the wells examined were plugged and abandoned and one well had been 'suspended' where the well head was still in place but had been disconnected from the gathering network and most of the surface equipment had been removed.

Twenty-nine wells were producing gas during the measurements, flowing at rates ranging from less than 1000 m^3 day^{-1} to more than 186,000 m^3 day^{-1}. Eleven of the sampled wells were hydraulically fractured. The selection also included a mix of free-flowing wells (water was not pumped from the well) and pumped wells (water was pumped from the well to allow gas flow). Pumped wells used on-site engines to power hydraulic pumps or generators to drive down-hole water pumps. In all but one case (which used diesel), these engines were fuelled from gas supplied from the well. A summary of the wells is shown in Table 4.1. To maintain commercial confidentiality, the well locations and operators of individual wells are not identified in this report.

Table 4.1. Details of wells examined during this study.

Well Number	Completion Date	Production Rate (m^3 day^{-1})	Fracture Stimulated	Type	Pump with Engine	Wells on Pad
A1	11/10/1999	1,470	Yes	Vertical	No	1
A2 - Suspended	1/05/2003	0	Yes	Vertical	No	1
A3	1/07/2007	0	Yes	Vertical	Yes – not running	1
A4	20/04/2010	18,400 (total of all 4 wells on pad)	No	Horizontal	No	4
A5	8/06/2011	14,900	No	Horizontal	Yes	2
A6	11/12/2007	13,700	No	Horizontal	No	1
B1	24/09/2006	38,880	No	Vertical	Yes	1
B2	11/01/2008	0	No	Vertical	No	1
B3	06/08/2011	9,360	No	Vertical	Yes – not running	1
B4	21/09/2010	26,400	No	Vertical	Yes – not running	1
B5	08/12/2010	0	No	Vertical	No	1
B6	27/04/2003	23,760	Yes	Vertical	Yes	1
B7	09/08/2007	26,400	No	Vertical	Yes	1
B8	26/01/2008	62,400	No	Vertical	No	1
B9	23/06/2008	7,680	No	Vertical	Yes	1
B10	07/04/2007	55,200	No	Vertical	No	1
B11	23/06/2011	94,602	No	Vertical	Yes – not running	1
B12	28/06/2011	0	No	Vertical	Yes – not running	1
B13	21/02/2005	0	No	Vertical	No	1
B14	30/08/2007	75,360	No	Vertical	No	1

B15	08/04/2009	70,800	No	Vertical	No	1
C1	15/05/2001	76,101	No	Vertical	Yes	1
C2	2/08/2003	853	No	Vertical	Yes	1
C3	4/10/2007	0	No	Vertical	Yes – not running	1
C4	29/03/2007	52,458	No	Vertical	Yes	1
C5	29/03/2007	58,594	No	Vertical	Yes – not running	1
C6	28/01/2008	186,464	No	Vertical	Yes	1
C7	17/09/2009	0	Yes	Vertical	No	1
C8	22/05/2010	0	No	Horizontal	No	2
C9	16/10/2003	78,731	Yes	Vertical	No	1
C10	1/10/2003	85,556	Yes	Vertical	No	1
C11	27/08/2004	0	Yes	Vertical	No	1
D1 - Abandoned	8/11/2003	0	No	vertical	No	1
D2	1/09/2005	93,400	Yes	vertical	No	1
D3 - Abandoned	29/11/2003	0	Yes	vertical	No	1
D4	19/04/2004	0	Yes	vertical	Yes (x2 – not running)	1
D5	7/11/2009	7,900	No	vertical	Yes (x2)	1
D6	28/11/2009	0	No	vertical	Yes (x2)	1
E1	16/3/2008	43,843 (total of both wells on pad)	No	vertical	Yes	2
E2	7/9/2008	26,847	No	vertical	Yes	1
E3	16/3/2007	3,707	No	vertical	Yes – not running	2
E4	31/5/2009	6,598	No	vertical	Yes	1
E5	31/5/2005	14,498 (total of all 3 wells on pad)	No	vertical	Yes	3

Downwind plume traverses were made at all wells sites except Wells B7 and C3 where the wind was too light to produce stable plumes. Of the well sites where traverses were made only three did not exhibit any CH_4 emissions. These were the two plugged and abandoned wells (D1 and D3) and the suspended well (A2). All of the other wells examined exhibited some level of CH_4 emissions although in most cases the amount was relatively small. The plume traversing results for all wells are presented in Table A1 in the Appendix.

On-pad measurements were made at most wells except in a few cases where high ambient CH_4 levels from major leaks or vents made locating minor leak points difficult. In one case at Well B2, CH_4 released from a vent on a water gathering line was drifting over the pad components so it was not possible to determine if

there were other leaks against the high background. Similar conditions were encountered at Wells C3 and E4 where variable plumes from leaks around the water pump shaft seals precluded reliable leak detection. In one case we attempted to measure emissions from a well about 500 m downwind of a gas compression plant but the CH_4 emissions from the plant prevented any measurements being made at this site.

Most of the CH_4 emissions were found to be derived from equipment leaks and venting but we also found that exhaust from the engines used to drive the water pumps on some wells was frequently a significant source of methane. Fifteen of the pumped wells had the engines operating during the measurements and in most cases the exhaust was found to contain CH_4 that contributed to total emissions. In a few cases, the plume from the engine exhaust was sufficiently spatially separated from other sources of CH_4 to quantify the sources separately using the traverse method (Figure 4.2).

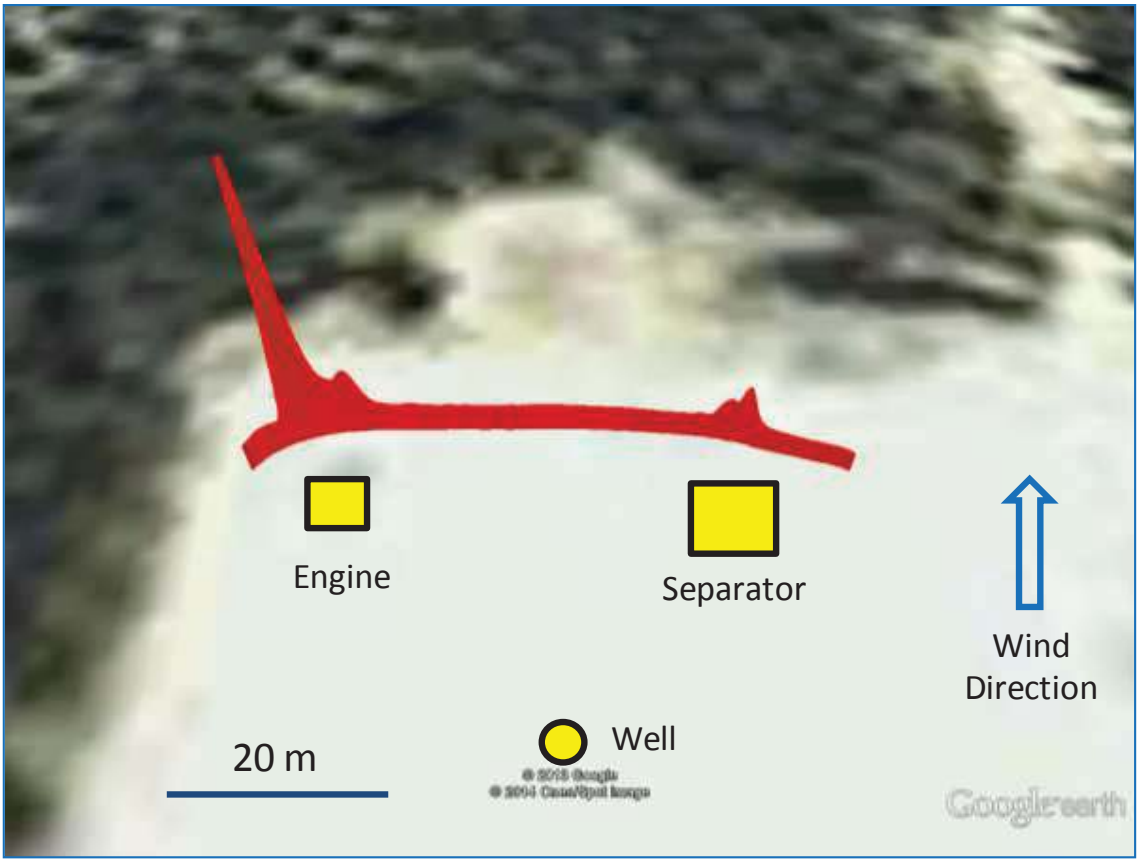

Figure 4.2. Methane concentration profile at Well C2 showing the separate plumes associated with the engine and equipment leaks elsewhere on the pad.

However, in most cases the plumes were coincident and the exhaust component could not be separated. To attempt to estimate the magnitude of engine emissions, we measured the CH_4 concentration in the exhaust outlet of the engine where this was possible. The range of CH_4 concentration varied considerably; from only a few ppm to more than 1500 ppm. The exhaust gas flow rate was estimated from the nominal fuel consumption (often stated on the engine nameplate) or power rating and assuming a 33 % efficiency and 17:1 air fuel ratio.

In the example for Well C2 shown in Figure 4.2, the plume traverse yielded an emission rate from the engine of 0.8 g min^{-1} compared to the estimate based on the fuel consumption and exhaust CH_4 concentration of 0.9 g min^{-1}. In another example, engine emissions from Well B7 were estimated using the exhaust method to be 0.2 g min^{-1}. A separate measurement made by the well operator using a stack testing method also gave 0.2 g min^{-1}. While these two examples suggest that this method provides a reasonable approximation of exhaust CH_4 emissions, in many cases the CH_4 concentration measured was well above

the calibrated range of the CH_4 analyser (i.e. > 280 ppm) and hence the results can only be considered indicative.

Although on-pad measurements provided reasonably accurate leak rate results for individual leak points, the large number of possible emission sources including equipment leaks, vents, pneumatic devices and engine exhaust presented a risk that some emission points on each pad would be missed during the surveys (Figure 4.3).

Figure 4.3. CSG well pad showing some of the surface equipment and potential emission points. Note the engine in the background for supplying hydraulic power to the water pump.

To check this we compared the emission rates determined from the on-pad measurements to those calculated from the downwind traverses, which capture all emissions from the pad. Ideally therefore, if all the emission sources have been accounted for, on-pad measurements should equal emission rates determined from traverse data. Apart from one result, there was generally good agreement between the two methods, which is shown in Figure 4.4 where the emission rate determined for each well by the on-pad methods is plotted as a function of the traversing results. The outlier (red marker in Figure 4.4) corresponds to Well B2 where the traverses were made under very light and variable conditions, which make accurate quantification difficult. The mean traverse result for this well was approximately 17 g min^{-1} but this result exhibited the greatest variably of all the traverses, ranging from 1 to 66 g min^{-1}. If this result is omitted from the plot, the slope of the line is close to 1 (0.94) confirming that the on-pad measurements generally accounted for the main emission points i.e. there were no major sources that were missed during the leaks surveys.

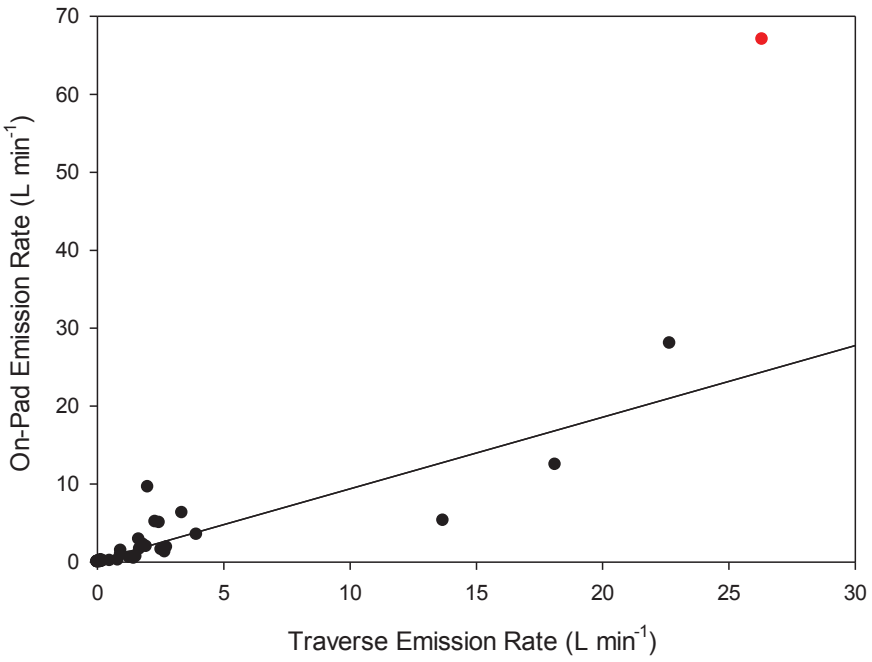

Figure 4.4. Correlation of total CH_4 emissions determined by traverses with on-pad measurements

The well site results from individual companies are discussed in more detail in the following sections.

4.2.1 COMPANY A

Figure 4.5 summarises the total emissions measured at Company A's well sites using the traversing method. At the time of the measurements only four wells were producing gas – Well A2 was suspended and Well A3 was shut-in for maintenance.

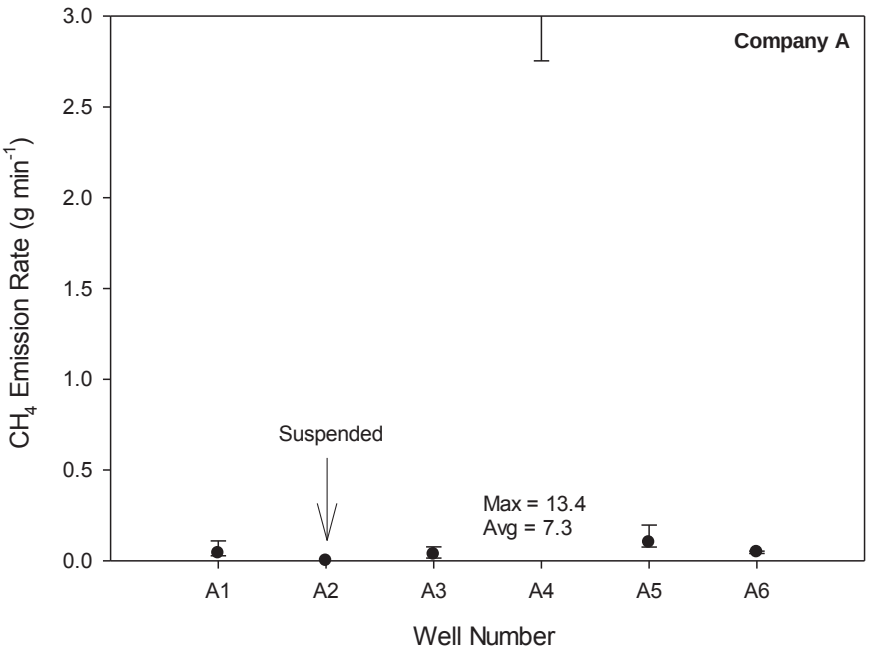

Figure 4.5. Total CH_4 emission rates estimated at Company A's well sites using the traversing method.

Apart from the suspended well (A2) emissions were detected at each site. Generally emissions were very low rwith five of the wells having emissions below about 0.1 g min^{-1}. On-pad measurements made at the well sites showed that in two cases (Wells A1 and A5) the emissions were due to the operation of pneumatic devices with emission rates of ~75 mg min^{-1} and 55 mg min^{-1}, respectively.

Two other wells (A3 and A6) were also found to have minor emissions but at the time the measurements were made, venting from pneumatic equipment was not contributing (i.e. these devices did not operate over the few hours we were on site at each well). In the case of A6, CH_4 was leaking slowly from a loose plug on a branch pipe at a rate of 22 mg min^{-1}. This leak was repaired by gas company personnel shortly after it was identified and further measurements on site showed that the leak had been eliminated. At Well A3, a leak was found in the gathering line, but again, this was very small amounting to less than 1 mg min^{-1}.

The largest emissions were found at Well A4. Two separate sets of traverses yielded an average emission rate of 7.3 g min^{-1}. Methane leaks were detected at a valve and pipe joint on the well pad but the combined emission rate from these was about 7 mg min^{-1} so the bulk of the methane release was from another source. This well was on a pad with three other wells within close proximity, which were not examined in detail during this campaign, so it is possible that some of the observed methane in the plume may have originated from these other wells. However, the bulk of the source was traced to a buried gathering line adjacent to the pad that serviced all four wells. We attempted to measure the emission rate using the surface flux chamber method; however, because of the diffuse nature of the emissions through the gravel, this was not successful.

Although the average emission rate of 7.3 g min^{-1} (15.5 m^3 day^{-1} at 15 °C) determined by the traverses was by far the largest emission source found at Company A, it represented only about 0.1 % of the indicated gas flow of 18,400 m^3 day^{-1} from the four wells on the pad.

A summary of the emissions determined by on-pad measurements at Company A is provided in Table 4.2.

Table 4.2. Summary of on-pad emission rates measured at Company A sites; nf denotes 'not found'. Note the leak rate shown for Well A6 was determined from the traverses.

Well Number	Leaks (g min^{-1})	Vents (g min^{-1})	Pneumatics (g min^{-1})
A1	3.3×10^{-4}	nf	7.5×10^{-2}
A2	0	nf	nf
A3	4.5×10^{-4}	nf	nf
A4	7.3	nf	nf
A5	0	nf	5.5×10^{-2}
A6	2.2×10^{-2}	nf	nf

4.2.2 COMPANY B

Methane emissions estimates based on the traverses for the Company B wells are summarised in Figure 4.6.

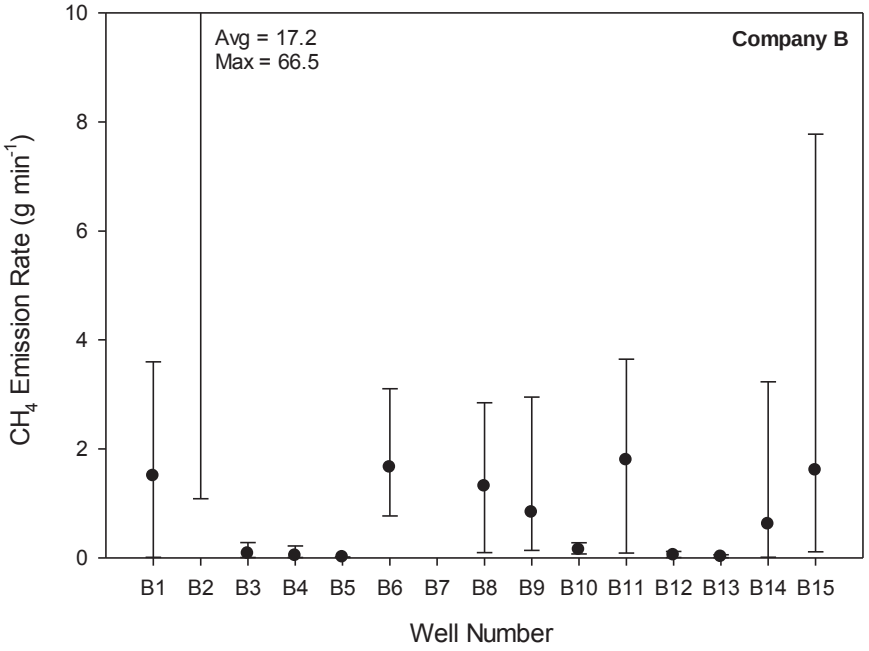

Figure 4.6. Total CH_4 emission rates estimated at Company B's well sites using the traversing method.

These emissions were somewhat higher than measured at Company A with average emissions ranging from less than 50 mg min^{-1}, (B4, B5, B12 and B13) to 17 g min^{-1} (B2). Note however, that one individual traverse on B2 indicated an emission rate of more than 66 g min^{-1}. The traverses at Well B2 were made under light and variable wind conditions so the results are subject to high uncertainty. More accurate emissions measurements of emissions were made at B2 using an on-pad method. In this case, CH_4 was found to be predominantly released from a single vent on a water gathering pipe from the well. The flow rate from the vent was relatively constant at 44 g min^{-1} (measured using a flow calibrator), which was within the range of the traverses but higher than the traverse average of 17 g min^{-1}. The high CH_4 emission rate however,

meant that it was not possible to identify any other sources on the pad because the plume was engulfing the surface equipment.

Well B2 was not flowing at the time of the measurements, but assuming the normal flow rate is 26,400 m^3 day^{-1} (i.e. the median production rate of the Company B wells examined), fugitive emissions from this vent represent about 0.4 % of the well's production.

Emissions at the other Company B well sites were much lower than B2, with emission rates generally less than 2 g min^{-1}. Most of the well sites exhibited a small level of leakage from certain items of equipment and especially a particular brand of pressure regulator. These regulator leaks however, were quite low with the maximum measured less than 25 mg min^{-1}. Most of the CH_4 emissions were, like Well B2, from vents present on many of this company's wells. Vent emissions were significantly higher than the equipment leaks, typically more than 1 g min^{-1}, with the maximum of 44 g min^{-1}.

The on-pad measurements for Company B are summarised in Table 4.3.

Table 4.3.Summary of on-pad emission rates measured at Company B sites; nf denotes 'not found'.

Well Number	Leaks (g min^{-1})	Vents (g min^{-1})	Pneumatics (g min^{-1})
B1	2.4×10^{-3}	2.9	nf
B2	nf	43.8	nf
B3	2.1×10^{-4}	nf	nf
B4	1.5×10^{-3}	nf	nf
B5	nf	nf	nf
B6	6.4×10^{-3}	1.0	nf
B7	9.6×10^{-4}	1.1	nf
B8	2.1×10^{-2}	6.2	nf
B9	2.4×10^{-3}	nf	nf
B10	2.3×10^{-2}	3.6×10^{-2}	nf
B11	2.5×10^{-2}	1.2	nf
B12	3.0×10^{-4}		nf
B13	1.0×10^{-3}	$< 10^{-4}$	nf
B14	3.94×10^{-3}	0.9	nf
B15	2.4×10^{-3}	3.3	nf

In addition to the emissions from the well pads, we found a significant CH_4 emission point from a water gathering line installation near Well B13 (Figure 4.7).

Figure 4.7. Methane emission sources on a water gathering line.

Methane was being released from the two vents shown in Figure 4.7 at a rate sufficient to be audible a considerable distance from the vents. It was not possible at the time to the site visit to directly measure the emission rate from the vents due to restricted access, however, the CH_4 concentration 3 m downwind of the vents was 15 % of the lower explosive limit of CH_4 (i.e. 7,500 ppm). Based on the prevailing wind speed, we estimate that the CH_4 emission rate from the two vents was at least 200 L min^{-1} (130 g min^{-1}) or almost 300 m^3 day^{-1}. This is a factor of three more than the highest emitting well examined during this study.

4.2.3 COMPANY C

Figure 4.8 summarises the CH_4 emission rates estimated by the traversing method for Company C. Emissions were generally estimated to be below 1.5 g min^{-1}, except for Wells C1 and C4, with emission rates of about 8.7 and 11.8 g min^{-1}, respectively. The bulk of the emissions from wells C1 and C4 were due to CH_4 in the engine exhaust rather than venting or equipment leaks. Similarly, emissions from Wells C2 and C6 comprised mainly CH_4 in engine exhaust although the emissions rates were much lower than C1 and C4. On-pad measurements at each of the wells showed that emissions from the wells were generally relatively low when the engine exhaust is excluded (Table 4.4). In this case, leaks were mostly less than 0.3 g min^{-1}. Most of these leaks were found to be from vent pipes on equipment such as pressure relief valves or pressure regulators similar to those on Company B's well sites. In one case (Well C10), a pneumatic device was found to be venting at an average rate of 0.5 g min^{-1} in addition to the equipment leak rate of 0.3 g min^{-1} to give a total emission of 0.8 g min^{-1}.

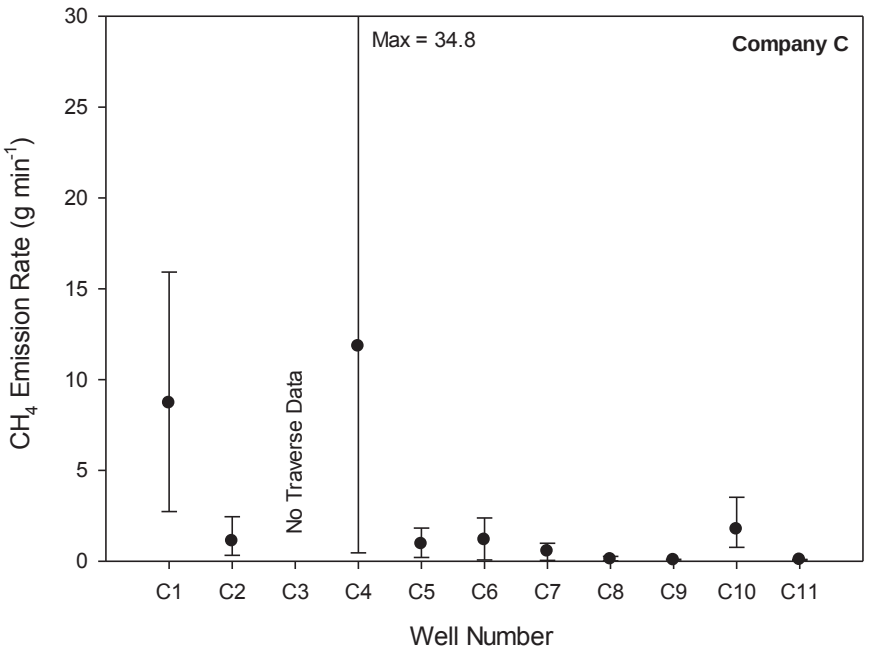

Figure 4.8. Total CH_4 emission rates estimated at Company C's well sites using the traversing method.

Traverses were not made at Well C3 due to lack of wind, however, on-pad inspections revealed a significant gas leak was on the seal of the water pump shaft. The emission rate from this leak was approximately 28 g min^{-1} (measured using the high-flow apparatus), which was the second largest well emission (after B2) and the largest equipment leak of the 43 sites examined. Since this well was shut-in at the time of measurement, it was not flowing but using the median flow rate of Company C's wells (52,500 m^3 day^{-1}) the leak rate corresponds to about 0.1 % of the well's production.

The water pump shaft seal was also found to be the source of CH_4 leakage at Well C5 but in that case, the emission rate was about 0.3 g min^{-1}, about 100 times less than C3.

Table 4.4. Summary of on-pad emission rates measured at Company C sites; nf denotes 'not found'.

Well Number	Leaks (g min^{-1})	Vents (g min^{-1})	Pneumatics (g min^{-1})
C1	5.3×10^{-2}	nf	nf
C2	0.2	nf	nf
C3	28.	nf	nf
C4	8.0×10^{-2}	nf	nf
C5	0.3	nf	nf
C6	0.2	nf	nf
C7	0.1	nf	nf
C8	2.1×10^{-3}	nf	nf
C9	8.9×10^{-3}	nf	nf

C10	0.3	nf	0.5
C11	7.4×10^{-2}	nf	nf

4.2.4 COMPANY D

Two of the wells at Company D were plugged and abandoned with all surface equipment removed. Detailed traverses and flux chamber measurements made on the well sites revealed no sign of any residual emissions from these wells. The traversing results for Company D are shown in Figure 5.9.

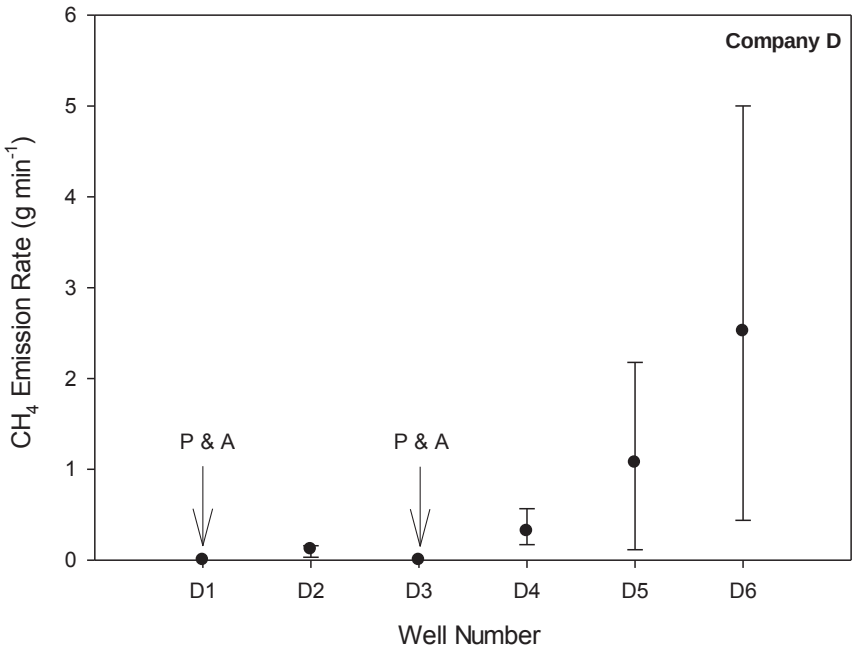

Figure 4.9. Total CH_4 emission rates estimated at Company D's well sites using the traversing method.

Of the operating wells, D2 had the lowest emissions with on-pad measurements indicating total emissions of less than 60 mg min^{-1}, which were due to minor equipment leaks. Well D4 also had low emissions totalling about 65 mg min^{-1}. A small emission from a pneumatic actuator of approximately 14 mg min^{-1} was also found on well D4.

Wells D5 and D6 had higher total CH_4 emission rates and although affected by engine exhaust, significant proportions of the observed emissions were due to equipment leaks. In the case of D5, most of the CH_4 was leaking from the water pump shaft seal at about 1.5 g min^{-1} (Table 5.5). For D6, we estimate that about two thirds of the CH_4 was due to engine exhaust but approximately 0.75 g min^{-1} was leaking from what appeared to be a damaged diaphragm in a valve actuator (Figure 5.10). Several smaller leaks on this well resulted in a total leak rate of about 0.9 g min^{-1}.

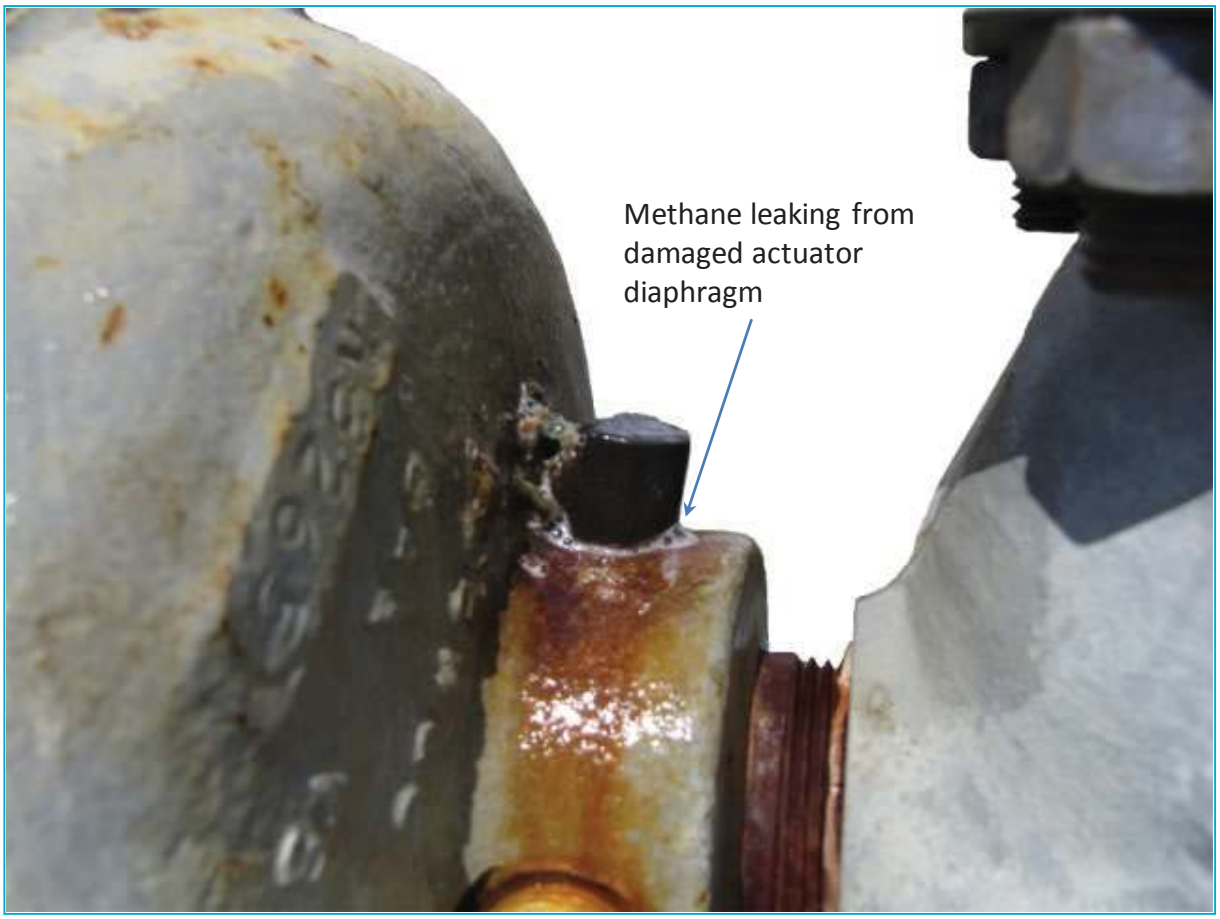

Figure 4.10. Methane leak from a valve actuator. Note the soap solution bubbles around the emission point.

Table 4.5 shows a summary of the on-pad results from Company D.

Table 4.5. Summary of on-pad emission rates measured at Company D sites; nf denotes 'not found'.

Well Number	Leaks (g min^{-1})	Vents (g min^{-1})	Pneumatics (g min^{-1})
D1	0	nf	nf
D2	5.7×10^{-2}	nf	nf
D3	0	nf	nf
D4	6.4×10^{-2}	nf	1.4×10^{-2}
D5	1.5	nf	nf
D6	0.9	nf	See note

Note: Although the emissions from the actuator shown in Figure 4.10 were from a pneumatic device, it appeared that this was due to a leak rather than normal operational emissions. Hence we have classified this as a leak in Table 4.5

4.2.5 COMPANY E

The traverse results obtained for Company E are shown in Figure 4.11. The lowest emitting well of the five examined was E5. This well was located on a pad of three wells, with a single engine providing power to all three water pumps. Emissions from all three wells were less than 60 mg min^{-1}, most of which were

probably associated with engine exhaust. We did not find any equipment leaks or venting emissions at this site.

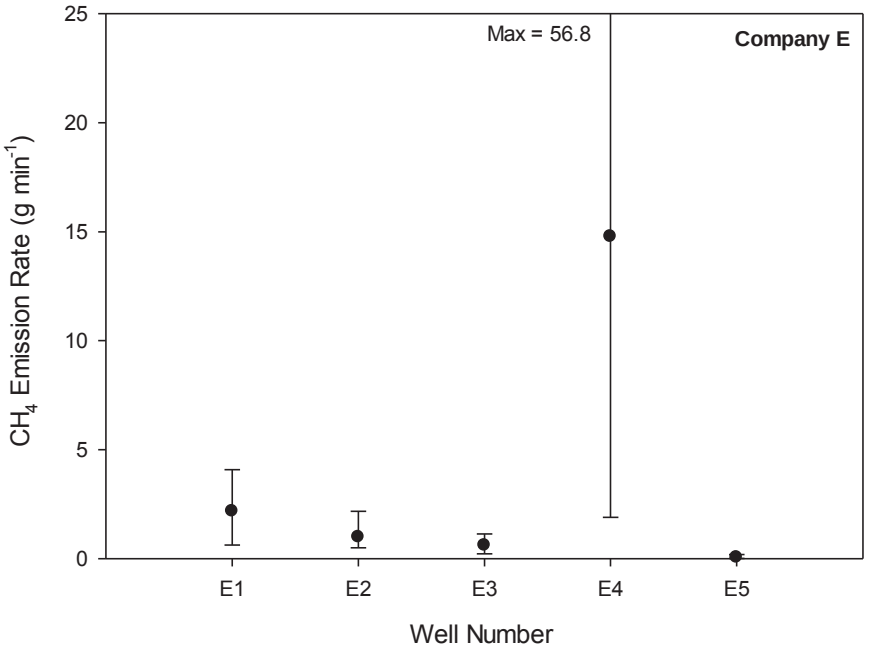

Figure 4.11. . Total CH_4 emission rates estimated at Company E's well sites using the traversing method.

The other wells, however, showed higher emissions, the largest of which was on Well E4 with an emission rate of about 15 g min^{-1}. This was traced to a leak on the water pump shaft seal. Like a number of other well sites examined during this study, the seal was repaired on site once the leak had been identified and subsequent measurements confirmed that CH_4 leakage was completely eliminated.

Well site E1 was also found to be leaking CH_4 from the water pump shaft seal. This site had two wells on the pad and both were found to be leaking from the seal. The combined rate of leak from this source was 0.7 g min^{-1}. These wells also showed significant leakage from two pressure regulators, similar to those used at various other well pads examined, with a combined emission rate of 1.7 g min^{-1}. Total emissions from leaks at E1 were 2.5 g min^{-1} (Table 4.6).

The next highest emitting well from Company E was E2 but most of these emissions were apparently from the engine exhaust. For E3, a very slight leak was detected from the pump shaft seal (about 40 mg min^{-1}) but most of the CH_4 emissions were from a leak in a filter attached to the engine fuel line (0.6 g min^{-1}).

Table 4.6. Summary of on-pad emission rates measured at Company E sites; nf denotes 'not found'.

Well Number	Leaks (g min^{-1})	Vents (g min^{-1})	Pneumatics (g min^{-1})
E1	2.5	nf	nf
E2	nf	nf	nf
E3	0.6	nf	nf
E4	15	nf	nf
E5	0	nf	nf

4.3 Casing Leaks

CSG wells are designed so that gas is extracted from the seam through a well casing but if the casing is damaged or improperly sealed into the surrounding strata, it is possible that gas can migrate to the surface outside the casing (Figure 4.12). To determine if CH_4 was escaping from the well casing, the flux chamber method was applied at each well site to measure the emission rate of any leakage from around the outside of the casing.

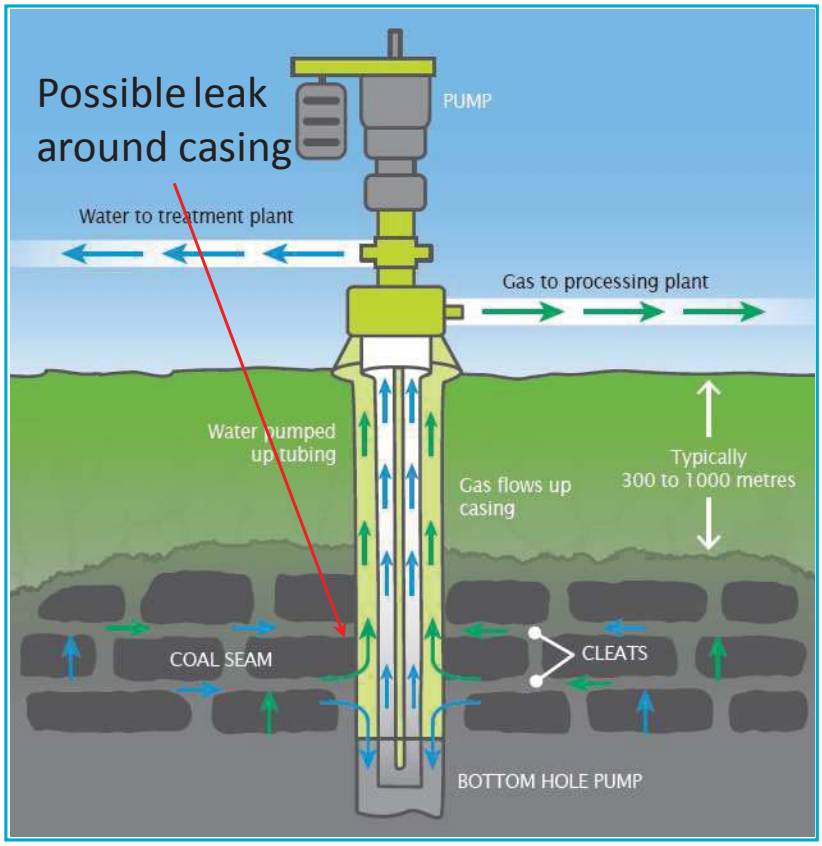

Figure 4.12. Schematic representation of a CSG well showing a possible route for CH_4 leaking outside a casing.

We anticipated that leakage from this source may be quite low, so it was important to ensure that the measurement technique had sufficient sensitivity to detect low level seepage. Therefore, prior to making field measurements a series of preliminary experiments were performed to determine the lower limit of detection of the method. Several experiments were made using a controlled release of CH_4 into the flux chamber system. Figure 4.13 (a) shows a plot of the CH_4 concentration within the chamber over about 5 minutes. The actual flow rate of CH_4 into the chamber was 7.76×10^{-5} g min^{-1} whereas the measured rate was 7.42×10^{-5} L min^{-1} or a difference of about 4 %. While this is a very low emission rate (cf. the smallest well leak rates of ~3×10^{-4} g min^{-1}) the ultimate sensitivity was several orders of magnitude lower. Measurement of CH_4 emissions from natural surfaces showed that emission rates less than 1×10^{-7} g min^{-1} could be reliably quantified (Figure 4.13 b).

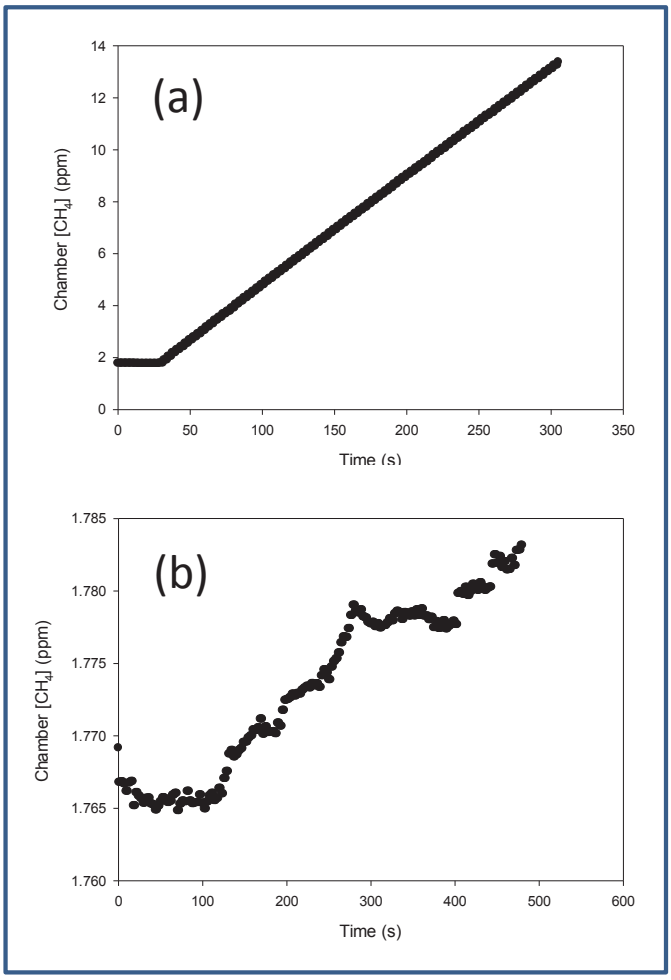

Figure 4.13. Methane concentration as a function of time in the flux chambers (a) controlled release experiment; (b) natural surface emission.

At the well sites, even with the very high sensitivity of the chamber method, we did not detect any emissions from around the well casing. Because the flux chamber measurements were applied at discreet points around the well it is possible that leak points were missed, however we believe that this was very unlikely since any significant emissions would have been detected during the mobile plume traverses and leak detection measurements made near the well heads.

5 Discussion

Overall, the emission rates measured at the well sites were quite low, especially when compared to the volume of gas produced. Of the 43 sites examined, 19 had emission rates less than 0.5 g min^{-1} and 37 less than 3 g min^{-1}; however, there were a number of wells with substantially higher emission rates up to 44 g min^{-1} (Figure 5.1).

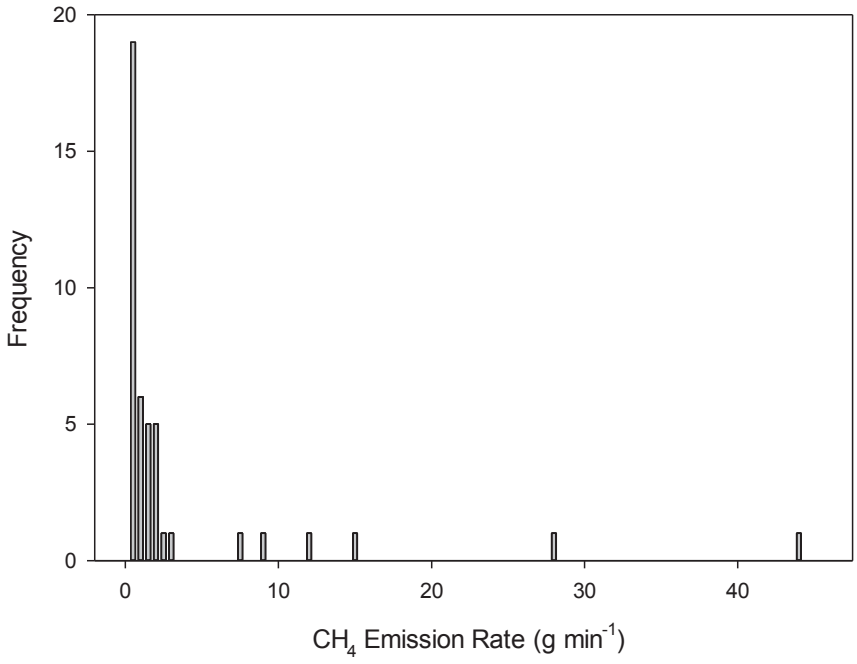

Figure 5.1. Histogram of emission rates from all sources measured at the 43 well sites.

Well pad emissions were found to be derived from several sources:

- exhaust from engines used to power dewatering pumps,
- vents and the operation of pneumatic devices and
- equipment leaks.

The mean emission rate of all of these sources for all wells is 3.2 g min^{-1} whereas the median (middle value) is 0.6 g min^{-1}.

Engine exhaust is not considered to be a fugitive emission for the purposes of greenhouse accounting since it is counted separately as a combustion source. Nevertheless, exhaust represented a significant proportion of the total CH_4 emissions at some well sites. The wide range of CH_4 concentrations present in the exhaust meant that the contribution of exhaust to overall emissions was highly variable. Some engines appear to have very low CH_4 emissions such as that at Well A5. Similarly, an unidentified well in Queensland was found to have no detectable CH_4 in the exhaust within close proximity to the pad (Day et al., 2013). On the other hand, engine exhaust was by far the primary source of CH_4 emissions at some wells (e.g. Wells C1 and C4).

As noted in Section 2, methane emissions from combustion are estimated for NGER reporting using an emission factor of 0.1 kg CO_2-e GJ^{-1} (DIICCSRTE, 2013b), which is equivalent to 4.8 g CH_4 GJ^{-1} using a global warming potential for CH_4 of 21. Assuming that the fuel consumption of the well site engines was 594 MJ

h^{-1} (indicated on the nameplate fitted to one make of engine commonly used throughout the industry), this equates to a CH_4 emission rate of 0.05 g min^{-1}, which lower than some of the estimates made during the study. Well C4 for example was estimated to be emitting CH_4 at a rate of 11.8 g min^{-1}.

Pneumatic devices, which are potential emission points, were installed at many wells, although during the measurement campaign, only seven of these were releasing CH_4 at the time of the site visits. Emissions from the these pneumatic devices ranged from 3.8×10^{-2} to 0.47 g min^{-1} with a mean emission rate 0.12 g min^{-1} and standard deviation of 0.18 g min^{-1}. This is somewhat lower than the emission rate for pneumatic devices recently reported by Allen et al. (2013). They found that the average emission rate from intermittent pneumatic devices at U.S. unconventional gas well was 5.9 ± 2.4 g min^{-1}. The result obtained for the Australian CSG wells is also lower than the production average emission factor for pneumatic devices provided in the API Compendium (API, 2009) of 345 ± 49.5 scf d^{-1} (4.6 ± 0.66 g min^{-1}).

It is not clear why these emission rates are lower than the U.S. estimates; however, it should be borne in mind that the results of our study represent only a very small sample. The Allen et al. (2013) study examined 305 devices compared to only seven in our study. Another reason for the difference may be due to the intermittent operation of the devices. Most of the CH_4 emission apparently occurs when the devices operate and hence the frequency of operation has a strong influence on the emission rate so a longer period of sampling may have yielded different results.

Despite the uncertainty of the results for pneumatic devices, it is probable that emissions from these systems will tend to decrease in the future. Some Australian CSG companies are now installing compressed air operated or electrical actuators on newer well pads which will eliminate pneumatic CH_4 emissions from these pads.

Vents installed at various points on some well pad equipment were frequently found to be sources of CH_4 emissions. Of the 43 well sites examined, ten had vents, all from Company B, that were emitting CH_4 at the time measurements were made. The rate of emissions varied substantially from less than 10^{-4} g min^{-1} up to 44 g min^{-1}, which was the highest rate of emissions measured from any source measured during this project. The mean vent emission rate was 6.1 g min^{-1} with a standard deviation of 13.4 g min^{-1}, reflecting the large range of values.

The third main source of well pad CH_4 emissions was from equipment leaks. Most of the wells examined were found to have some degree of leakage from equipment on the pad. Minor leaks (usually less than 60 mg min^{-1}) were found on various items such as fuel lines to engines, valves, sight gauges on separators and other equipment. However, there were some leak points that were consistently found across the well sites. The first of these was a particular type of pressure regulator installed at many wells (Figure 5.2). This device was apparently associated with the separator and was usually found to be leaking a small amount of CH_4. Mostly, these leaks were less than 150 mg min^{-1} but in one case (Well E1) the emission rate was about 1.5 g min^{-1}.

Figure 5.2. Pressure regular that was a common source of CH_4 leakage.

The other common leak point was the seal around water pump shafts on pumped wells (Figure 5.3). The two largest equipment leaks detected were due to leaking seals at Wells C3 and E4. At the time of the site visit, Well C3 was shut-in for maintenance and as a result the pressure on the seal was almost 2 MPa, which was much higher than normal operating pressure and this is likely to have contributed to the high leak rate from the well. This is consistent with a study of leaking wells in Queensland made in 2010 where high CH_4 concentrations (up to 6 % CH_4) due to leaks were often found on shut-in wells that were under high pressure (DEEDI, 2010).

Figure 5.3. Well head showing the location of the water pump shaft and seal which was found to be a common leak point.

At Well E4, the seal had apparently 'dried out' since the previous inspection and was allowing CH_4 to leak around the rotating pump shaft at almost 15 g min^{-1}. After the leak was identified, however, maintenance staff applied more grease to the seal and tightened the gland around the shaft, which effectively eliminated the leak. A smaller leak of around 1.5 g min^{-1} on the shaft seal on Well D5 was also repaired on site by simply tightening the gland.

Although the water pump shaft seal is a potentially large source of CH_4 emissions, it is clear that in many cases these leaks can be easily repaired. Regular inspection of these seals, especially during shut-ins when the well pressure may increase substantially, is therefore likely to be important for minimising well site emissions.

None of the wells examined during this study exhibited any sign of CH_4 emissions around the well casing so this does not appear to be a common route for CH_4 release. Methane leaks have been detected at ground level adjacent to well casings on Australian CSG wells previously but these were traced to leaks in the threaded connection between the casing and well head base (DEEDI, 2010) rather than gas leaking around the outside of the casing.

Despite this, it has been suggested that 6 to 7 % of well completions in the United States are subject to integrity failure that could lead to CH_4 leakage (Ingraffea, 2013). Given that we surveyed less than 1 % of

Australian CSG wells, it is possible that the small sample size is not sufficiently representative to assess the true extent of well leakage. Further work would be required to conclusively determine the extent of casing leaks.

Four of the wells surveyed were horizontal; the remainder were vertical. The range of emissions from the four horizontal wells was 0.05 to 7.3 g min^{-1} compared to 0 to 44 g min^{-1} for the vertical wells. It is not possible based on only four wells to determine if horizontal wells have different emission characteristics compared to vertical; however, it seems unlikely that this would be the case. The emission routes were always associated with surface equipment, some of which was common to both horizontal and vertical well pads.

Eleven wells examined had been hydraulically fractured and as shown in Table 5.1, average emissions from these wells were lower (0.42 g min^{-1}) than those measured on the unfractured wells (4.2 g min^{-1}). Because the data are heavily skewed and it is unlikely that the sample size is statistically representative, it is misleading to draw conclusions about the relative emission rates based on a comparison of means alone. Methane emissions were observed from both fracture stimulated and unfractured wells but in all cases, emissions were from surface equipment that would not be expected to be affected by the stimulation method. Therefore, the observed difference between the emission rates of the fractured and unfractured wells in this sample is probably unrelated to the stimulation method.

Table 5.1. Comparison of emission rates measured on hydraulically fractured and unfractured wells.

	Fractured	Unfractured
Number of Wells	11	32
Mean (g min^{-1})	0.42	4.2
Median (g min^{-1})	0.07	1.0
Std Deviation (g min^{-1})	0.66	14.3

Another parameter that was initially thought to possibly contribute to differences in emission rates was the well production rate. The range of gas production from the wells varied substantially but there was no observable correlation between production and leak rate. The highest emissions were from wells that were not producing gas at the time of the measurements. In the case of one of the non flowing wells (C3) at least, it may have been that the high well pressure due to the shut-in was contributing to the high leakage. Conversely, Well C6, which was producing about 186,000 m^3 day^{-1} (cf. the median production rate of 13,700 m^3 day^{-1}) had relatively low emissions, most of which were derived from the exhaust from the engine on the well pad.

Despite the rather low well pad emissions measured during this study, a much higher emission source was identified on a water gathering line installation. Unfortunately accurate measurements could not be made at this site but indicative estimates suggested that the emission rate from this source was at least three times higher than the largest emission rate measured on any of the wells. Similar installations are widespread through the Queensland gas regions and occasionally, gas can be heard escaping from vents on these systems. It is possible that these may be a significant source of CH_4 and is an area that needs further investigation.

5.1 Emission Factors

As discussed in Section2 emissions from equipment leaks are often estimated for NGER reporting according to Method 1 using a generic emission factor of 1.2 kg CO_2-e t^{-1}, which is equivalent to 57 g CH_4 t^{-1}. It is therefore instructive to compare this emission factor to the leak emission data measured in the field. The field measurements yielded a median leak rate 0.02 g min^{-1} and mean rate of 1.6 g min^{-1} from the 35 wells

where leaks were found. The median production rate of the wells was 13,700 m^3 day^{-1} or 9.3 t CH_4 day^{-1} (referenced to 15 °C). Dividing the median daily leak rate by the median production rate gives an emission factor of approximately 4 g CH_4 t^{-1} or 0.1 kg CO_2-e t^{-1} (based on a global warming potential of 21). Using the mean leak rate of 1.6 g min^{-1} and mean production rate of 29,600 m^3 day^{-1} yields an emission factor of 115 g CH_4 t^{-1} or 2.4 kg CO_2-e t^{-1}. This range is consistent with the current NGER emission factor for general equipment leaks and tends to confirm that equipment leaks comprise only a very small proportion of greenhouse gas emissions from CSG production.

Similar calculations may be made to develop emission factors for vents and pneumatic equipment. A summary of the emission data for leaks, vents and pneumatic equipment and the corresponding emission factors calculated from these data are shown in Table 5.2.

Table 5.2. Summary of emission data from leaks, vents and pneumatic equipment. Emissions factors calculated from the mean emission rate for each category are also shown in units of kg CO_2-e t^{-1} (GWP of 21 used in this calculation).

	Equipment Leaks	Vents	Pneumatic Equipment
Mean (g min^{-1})	1.59	6.05	0.12
Median (g min^{-1})	0.02	1.14	0.06
Std Dev	5.36	13.40	0.18
N	35	10	7
Calculated Emission Factor from Mean Emission Rate (kg CO_2-e t^{-1})	2.4	9.1	0.2

Although these averaged emission factors are low it should be remembered that firstly, the number of wells examined was less than 1 % of wells in operation so may not be representative of the total well population and secondly, there were several equipment leaks that were much higher than the average values (Figure 5.1). The maximum leak rate measured in this study was about 28 g min^{-1} on Well C3 and although this well was not flowing at the time, based on the median production rate for all wells, is equivalent to 91 kg CO_2-e t^{-1}. A high leak rate of 15 g min^{-1} was also found at Well E4 and based on its production rate, equates to 102 kg CO_2-e t^{-1}. These leak rates are about two orders of magnitude higher than the current NGER emission factor for equipment leaks.

Another important point with regard to the reliability of emission factors is that they may change due to operating conditions or maintenance. For instance, the leak from Well E4 discussed above was repaired during the site visit and completely sealed. Several other leaks were effectively repaired during the course of the visits once they were identified. However, since wells operate largely unattended, there may be some time between when the leak forms and when it is repaired.

With regard to well casing leaks there is currently no emission factor representative of Australian operations for estimating emissions. The current Method 2 emission factor is based on measurements made at some Canadian wells during the mid 1990s (CAPP, 2002). While there have been suggestions that well leakage may be a significant source of emissions (Somerville, 2012), the wells examined in this study showed no evidence of emissions via this route. But again, this needs to be considered in the context of the small number of wells examined.

6 Conclusions

Fugitive CH_4 emission rates were measured at 43 CSG well sites in Queensland and NSW. A range of methods was applied including downwind traverses of CH_4 plumes originating from well pads, and on-pad measurements to determine leak rates from individual items of equipments and well casings.

Emission rates from production sites ranged from zero to a maximum of about 44 g min^{-1}. The highest emission rate was due to CH_4 released from a vent on the well pad while the lowest emitters were two plugged and abandoned wells and a suspended well. All of the producing wells were found to have some level of emissions, although in all cases these were very low compared to overall production. Emissions were found to comprise equipment leaks, venting, pneumatic device operation and engine exhaust. The wells examined in this study did not show any evidence of CH_4 migration outside the well casing.

Overall, the median CH_4 emission rate from all sources for the wells examined was approximately 0.6 g min^{-1} while the mean emission rate was about 3.2 g min^{-1} or about 7 m^3 day^{-1}. This compares to a mean production rate of the 43 wells of 29,600 m^3 day^{-1} and represents about 0.02 % of total production. This is very much lower than recent estimates of CH_4 emissions from unconventional gas production in the United States.

Apart from vents, highest emissions were due to CH_4 leaking from seals on water pump shafts. On several occasions, these leaks were repaired on site once they were identified. The median emission rate of all the equipment leaks identified was 0.02 g min^{-1} and the mean was 1.6 g min^{-1}, which yield emission factors of about 0.1 kg CO_2-e t^{-1} and 2.4 kg CO_2-e t^{-1}, respectively. This range is consistent with the emission factor currently used in the National Energy and Greenhouse Reporting Method 1 methodology for estimating equipment leaks.

Although well pad emissions were generally found to be low, one significantly higher emission source was found on a vent associated with a water gathering line. This source appeared to be at least three times higher than the highest emission rate from any well examined.

The results obtained in this study represent the first quantitative measurements of fugitive emissions from the Australian CSG industry; however, there are a number of areas that require further investigation. Firstly, the number of wells examined was only a very small proportion of the total number of wells in operation. Moreover, many more wells are likely to be drilled over the next few years. Consequently the small sample examined during this study may not be truly representative of the total well population. It is also apparent that emissions may vary over time, for instance due to repair and maintenance activities. To fully characterise emissions, a larger sample size would be required and measurements would need to be made over an extended period to determine temporal variation.

In addition to wells, there are many other potential emission points throughout the gas production and distribution chain that were not examined in this study. These include well completion activities, gas compression plants, water treatment facilities, pipelines and downstream operations including LNG facilities. Emissions from some of these sources are often estimated for reporting purposes using methodology based on emission factors largely derived from the U.S. gas industry. However, reliable measurements on Australian facilities are yet to be made and the uncertainty surrounding these some of these estimates remains high.

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Appendix

Table A1. Results of the downwind traverse measurements for each well. The average results shown for Wells B2, B7 and C3 were measured on each well pad. All units are g min^{-1}.

Well Number	Average	Minimum	Maximum	Std Deviation
A1	0.04	0.03	0.11	0.03
A2 - Suspended	0.00	0.00	0.00	0.00
A3	0.04	0.02	0.08	0.02
A4	7.28	2.75	13.42	3.38
A5	0.10	0.08	0.20	0.06
A6	0.05	0.04	0.05	0.01
B1	1.50	0.01	3.60	1.22
B2	43.8 (on pad)	1.09	66.5	22.5
B3	0.07	0.01	0.28	0.08
B4	0.04	0.01	0.22	0.06
B5	0.01	0.01	0.02	0.00
B6	1.66	0.77	3.10	0.74
B7	1.27 (on pad)			
B8	1.31	0.10	2.85	0.98
B9	0.83	0.14	2.95	0.81
B10	0.15	0.07	0.28	0.07
B11	1.79	0.09	3.65	1.07
B12	0.05	0.01	0.12	0.03
B13	0.02	0.01	0.06	0.02
B14	0.61	0.01	3.23	0.98
B15	1.61	0.11	7.78	2.35
C1	8.69	2.73	15.9	4.77
C2	1.10	0.33	2.45	0.66

C3	28.0 (on pad)			
C4	11.8	0.46	34.8	12.4
C5	0.93	0.21	1.82	0.56
C6	1.17	0.07	2.38	0.71
C7	0.54	0.04	0.99	0.35
C8	0.10	0.02	0.27	0.08
C9	0.05	0.01	0.10	0.03
C10	1.75	0.76	3.52	0.82
C11	0.07	0.05	0.10	0.02
D1 Abandoned	0.00	0.00	0.00	0.00
D2	0.12	0.03	0.16	0.04
D3 Abandoned	0.00	0.00	0.00	0.00
D4	0.32	0.17	0.57	0.13
D5	1.07	0.11	2.18	0.71
D6	2.52	0.44	5.00	1.42
E1	2.17	0.63	4.08	1.19
E2	0.99	0.50	2.17	0.55
E3	0.60	0.22	1.13	0.33
E4	14.8	1.89	56.8	18.8
E5	0.06	0.01	0.19	0.06

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