EPA's Greenhouse Gas Reporting Program: Implementation Progress and Lessons Learned for Onshore Petroleum and Natural Gas Production Operations

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Abstract

This paper addresses lessons learned from the initial phases of greenhouse gas (GHG) reporting for the upstream Petroleum and Natural Gas industry (under 40 CFR Part 98 Subpart W). It will emphasize the unique aspects of reporting GHG emissions for onshore petroleum and natural gas production operations and the need to balance reliable information and reporting burden through instrumentation, data collection practices, company Information Technology (IT) systems and interfacing with EPA's electronic GHG reporting tool (eGGRT). It will also discuss the impact of these reporting rules on Canadian operations in those provinces that are part of the Western Climate Initiative.

Keywords: greenhouse gas reporting, petroleum and natural gas production

Résumé

Cette intervention porte sur les leçons tirées des phases initiales de déclaration des gaz à effet de serre pour le secteur en amont de l'industrie pétrolière et gazière (en vertu du 40 CFR partie 98 sous-partie W). Nous soulignerons l'aspect singulier de la déclaration des émissions de gaz à effet de serre pour la production terrestre de pétrole et de gaz naturel et la nécessité d'équilibrer la charge de déclaration et d'information fiable par l'utilisation d'instruments, de pratiques de recueil de données, de systèmes de technologie de l'information des sociétés, et d'interface avec l'outil électronique de documentation de l'EPA (eGGRT). Nous considérerons également l'impact de ces règles de documentation sur les opérations dans les provinces canadiennes qui font partie de la Western Climate Initiative.

Mots clés: déclaration des gaz à effet de serre, production de pétrole et de gaz naturel

1. Introduction

The U.S. Environmental Protection Agency (EPA) promulgated its first rule governing the mandatory reporting of greenhouse gas (GHG) emissions in October 2009. These reporting rules apply broadly to most public and private sectors of the economy and encompass direct GHG emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO_2 underground. The reporting requirements appear in multiple subparts of Title 40 Part 98 of the Code of Federal Regulations (40 CFR 98). These rules are collectively referred to as the Greenhouse Gas Reporting Program (GHGRP) and detail the emission estimation and reporting requirements for facilities in 41 industrial categories whose facility-level annual GHG emissions exceed 25,000 tonnes of carbon dioxide equivalent (CO_2e) emissions.

Title 40 CFR Part 98 Subpart W provides requirements for reporting vented and fugitive GHG emissions from eight industry segments that make up the sector known as Petroleum and Natural Gas Systems. Facilities are required to calculate GHG emissions according to the specified calculation methodologies for each source type within the applicable industry segment. These range from application of specified emission factors, engineering calculations, and direct emissions measurements.

Prior to EPA's actions on a national level, several states and regions had taken steps to report and manage GHG emissions. In particular, the Western Climate Initiative (WCI) built on initiatives by Arizona, California, New Mexico, Oregon, and Washington. WCI began in February 2007 when the Governors of those five states agreed to develop a regional GHG program with the objectives of developing a registry to track and manage GHG emissions in the region and establishing a market-based program to reach a regional target for reducing GHG emissions.

The Premiers of British Columbia, Manitoba, Ontario, and Quebec, and the Governors of Montana and Utah joined the original five states in 2007 and 2008. All 11 jurisdictions collaborated on the development of the *Design Recommendations for the WCI Regional Cap and Trade Program* in 2008 [1], and the *Design for the WCI Regional Program* [2] in 2010. These documents provide roadmaps to inform the WCI Partner jurisdictions as they implement the cap-and-trade program in their jurisdictions.

The WCI cap-and-trade program is intended to cover emissions of seven greenhouse gases (carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride, and nitrogen trifluoride) from the following types of emission sources:

- Electricity generation, including electricity imported into the WCI region;
- Industrial fuel combustion;
- Industrial processes;
- Transportation fuel use; and
- Residential and commercial fuel use.

The first phase of the cap-and-trade program was scheduled to begin on January 1, 2013, covering emissions from electricity generation, electricity imports, industrial combustion at large sources, and industrial process emissions for which adequate measurement methods exist. The second phase begins in 2015, when the program expands to include transportation fuels and residential, commercial and industrial fuels not otherwise covered in the first phase.

2. Onshore petroleum and natural gas reporting requirements

2.1 U.S. EPA requirements

Although petroleum refining operations were required to report GHG emissions starting with calendar year 2010, the upstream segments that comprise the petroleum and natural gas sector were not included in the GHGRP until November 2010, with reporting to begin for calendar year 2011. One of the eight segments in this industry, onshore petroleum and natural gas production operations require annual reporting of emissions for up to 19 different emission source types.

Reporting for onshore petroleum and natural gas operations introduced a revised definition of a "facility", evolving from any "*physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas*" [3] to "*all petroleum or natural gas equipment on a single well-pad or associated with a single well-pad and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin*" [4]. This expansion of the definition of "facility" to encompass an entire basin (as defined by the American Association of Petroleum Geologists) results in data gathering requirements for hundreds of thousands of discrete sites and sources that are broadly dispersed geographically and whose emissions must be quantified and reported. This results in a strong need for instrumentation to aid in data collection, company Information Technology or database systems to compile and manage the required information, and a smooth interface with EPA's electronic GHG reporting tool (eGGRT) [5].

2.2 Canadian reporting requirements

From a national perspective, Environment Canada's Greenhouse Gas Emissions Reporting Program applies only to the largest industrial GHG emitters in Canada which are those emitting the equivalent of 50,000 tonnes (50 kilotonnes) or more of GHGs as CO_2e per year. Emissions reported under the Energy Sector include fugitive emissions from the fossil fuel industry, which consist of flaring emissions, equipment leaks, and accidental releases from production, processing, transmission and storage of fuels. Environment Canada defines a facility as a contiguous facility, a pipeline transportation system, or an offshore installation. As a result, unlike the U.S. requirements, a facility for onshore petroleum and natural gas production operations would consist of clusters of production equipment around a wellsite or central facility, and would likely not exceed the emission threshold for reporting.

With four of the Canadian provinces participating in the WCI program, WCI published the *Final Harmonization of Essential Reporting Requirements in Canadian Jurisdictions* [6] to incorporate Canada-specific reporting metrics and factors, while also ensuring harmonization with the U.S. reporting requirements and consistent quantification methods for all source categories for the Canadian partners.

Quantification methods for the petroleum and natural gas sector were evolving in the U.S. as the Canadian Harmonization document was developed. As a result, some technical elements of the U.S. EPA November 8, 2010 Subpart W (Petroleum and Natural Gas Systems) requirements were not reflected in the 2010 Canadian reporting requirements. These include revisions to the EPA MRR which were made in 2011 and 2012. Updates to the *Final Essential Requirements of Mandatory Reporting* [7] incorporated changes to align with the EPA requirements, but still includes some distinct and important differences from EPA's reporting requirements. Specific examples include:

- Different facility definitions for onshore petroleum and natural gas operations;
- Different reporting thresholds (For WCI: 10,000 tonnes for an individual facility and the aggregate of facilities less than 10,000 tonnes; for EPA: 25,000 tonnes for a facility)
- WCI includes gathering pipelines and tanks that handle gas produced from multiple wells. EPA has not yet addressed mid-stream operations, and petroleum and natural

gas production requires reporting for equipment on a single well-pad or associated with a single well-pad.

- WCI includes several emissions sources or source categories for petroleum and natural gas production operations that are not required by EPA. These include: transmission storage tanks, pipeline damage caused by third parties, blowdown vent stacks, other venting sources, and other fugitive sources.

WCI's Reporting Committee has developed cap and trade quality reporting requirements for sources covered by Subpart W for use in both Canadian and U.S. jurisdictions. These revisions are expected to be reflected in data reported for calendar year 2012.

3. Lessons learned from EPA reporting for onshore petroleum and natural gas operations

Facilities in the U.S. that belong to the identified sectors of the petroleum and natural gas industry, which were required to report under Subpart W, submitted their first emissions data to EPA in September 2012 for reporting year 2011. EPA published 2011 emissions data for the petroleum and natural gas industry amongst data for all other reporting sectors in early February 2013 [8], providing detailed facility emissions information through online database tools. Table 1 provides a summary of the total reported GHG emissions for all sectors of the economy reported for calendar year 2011.

Table 1. 2011 Total Reported GHG Emissions for All Sectors of the Economy from EPA's Greenhouse Gas Reporting Program

Industry Sector	Emissions (Million metric tonnes CO_2e)	Percent of reported emissions	Number of Reporters
Power Plants	2,221	67%	1,594
Petroleum and Natural Gas Systems	225	7%	1,880
Refineries	182	6%	145
Chemicals	180	5%	458
Waste	103	3%	1,593
Metals	115	3%	297
Minerals	98	3%	362
Pulp and Paper	44	1%	230
Other	126	4%	1,377
TOTAL	3,294		7,936

Facilities reporting for Subpart W are represented in Table 1 under Petroleum and Natural Gas Systems, which includes emissions from nine segments: onshore petroleum and natural gas production, offshore petroleum and natural gas production, natural gas processing, natural gas transmission/compression, underground natural gas storage, LNG storage, LNG import and export operations, and local natural gas distribution. Emissions associated with each of these segments are shown in Table 2. Of the 225 million metric tonnes of CO_2 equivalent (MMT CO_2e) emissions attributed to Petroleum and Natural Gas Systems, 94 MMT CO_2e are attributed to onshore petroleum and natural gas production.

Table 2. 2011 EPA's Greenhouse Gas Reporting Program: Petroleum and Natural Gas Systems Emissions

Industry Sector	Emissions (Million metric tonnes CO_2e)	Percent of reported emissions	Number of Reporters
Onshore Petroleum & Natural Gas Production	94	42%	448
Offshore Petroleum and Natural Gas Production	6	3%	99
Natural Gas Processing	62	28%	372
Natural Gas Transmission/Compression	24	11%	424
Natural Gas Storage	1	0.4%	44
Natural Gas Local Distribution Companies	14	6%	168
Liquefied Natural Gas Storage	**	**	5
Liquefied Natural Gas Import/Export	0.7	0.3%	7
Other Petroleum and Natural Gas Systems	23	10%	331
TOTAL	225		1898

** Total reported emissions are less than 0.5 million metric tons CO_2e.

At the same time the U.S. EPA published data from the 2011 GHGRP, EPA also released the 2011 annual national GHG inventory for public review and comment in early March. The inventory is expected to be published in mid-April 2013 when the U.S. EPA also submits the inventory to the secretariat of the United National Framework Convention on Climate Change (UNFCCC), as part of its global obligations under the convention.

Tables 3 and 4 exhibit the contribution of each emission source from the 2011 national GHG inventory to the total emissions estimated for petroleum and natural gas production operations, respectively. Table 3 presents potential emissions, emission reductions included in EPA's inventory, and the net source emissions for those sources where EPA derived reductions from information reported under the Gas STAR program or through federal or state regulations [9]. The percent contribution values shown are based on the sum of total emissions from petroleum and natural gas production operations after accounting for EPA's reported reductions[1].

Key changes reflected in the 2011 national GHG inventory for natural gas systems, when compared to that of 2010, include the use of a new database (DI Desktop) for developing well count information; updating the emission factors for gas well liquids unloading with and without plunger lifts; and decreasing the assumed workover (refracture) rates from 10% to 1% for gas wells that were originally completed with hydraulic fracturing. No methodological changes were made to the emission estimates for petroleum systems.

Overall, methane emissions for natural gas systems were estimated to be 215.4 million metric tonnes CO2e in the 2010 inventory. According with international practices, methodological changes require a recalculation of the time series to preserve the validity of the trend-line. The recalculated 2010 emissions for natural gas systems are 144 million metric tonnes CO2e, with the 2011 emissions being 139.6 million metric tonnes CO2e, or a decrease of 4.4 million metric tonnes CO2e.

[1] EPA's reported reductions were aligned to specified sources where possible. EPA reported reductions for gas well completions and workovers with hydraulic fracturing combined. Table 2 applies this reduction just to completions with hydraulic fracturing. EPA also reports "other reductions" which are not assigned to specific sources. As a result, the % contributions values shown are estimated based on the assigned reductions shown in the table, and do not reflect reductions in the "other" category. Also, the percent contribution for workovers with hydraulic fracturing does not reflect reductions that are combined with completions.

Table 3. Methane Emissions from Natural Gas Production Operations as Reported in EPA's 2011 National GHG Inventory.

Natural Gas Production Emission Sources	Potential Source Emissions (metric tonnes CO_2e)[1]	Emission Reductions (metric tonnes CO_2e)	Source Emissions Net Reductions (metric tonnes CO_2e)	% of Total Production (Oil and Gas)
Gas Wells				
Non-associated Gas Wells without Hydraulic Fracturing	23,758		23,758	1%
Gas Wells with Hydraulic Fracturing	27,523		27,523	1%
Field Separation Equipment	272,736		272,736	6%
Gathering Compressors	252,963		252,963	6%
Drilling and Well Completion				
Gas Well Completions without Hydraulic Fracturing	12		12	0%
Gas Well Completions with Hydraulic Fracturing	1,221,264	760,000	461,264	10%
Well Drilling	763		763	0%
Normal Operations				
Pneumatic Device Vents	1,133,738	778,000	355,738	8%
Chemical Injection Pumps	63,618		63,618	1%
Kimray Pumps	364,910	179,700	185,210	4%
Dehydrator Vents	113,783	36,500	77,283	2%
Condensate Tank Vents	312,879	83,800	229,079	5%
Compressor Exhaust Vented	275,869	49,100	226,769	5%
Well Workovers				
Gas Wells without hydraulic fracturing	579		579	0%
Gas Wells with hydraulic fracturing	266,179		266,179	6%
Liquids unloading with plunger lifts	108,433		108,433	2%
Liquids unloading without plunger lifts	148,504		148,504	3%
Blowdowns	11,851		11,851	0%
Upsets	2,189		2,189	0%
Produced water from coal bed methane	58,557		58,557	1%
Offshore Platforms	289,017		289,017	7%
Other reductions (Sources not specified)		764,100		
TOTAL Emissions, CH_4 as metric tonnes CO_2e	4,949,125		2,297,925	

[1] metric ton = Mg

Table 4. Methane Emissions from Petroleum Production Operations as Reported in EPA's 2011 National GHG Inventory.

Petroleum Production Emission Sources	Source Emissions Net Reductions (metric tonnes CO_2e)	% of Total Production (Oil and Gas)
Pneumatic device venting	428,581	9%
Tank venting	221,400	5%
Combustion & process upsets	98,873	2%
Misc. venting & fugitives	702,023	16%
Wellhead fugitives	23,974	1%
TOTAL Emissions, CH_4 as metric tonnes CO_2e	1,474,780	

With one reporting cycle completed and the second in development, several areas for improvement of the EPA reporting requirements have been voiced by API members. Data gathered by API from recent survey mechanisms and feedback from member companies form the basis for the following information.

3.1 Deriving new emission factors

For some segments of the petroleum and natural gas industry, Subpart W of the GHGRP includes requirements for annual measurements from vents or surveys of process component leaks. These requirements do not take into account many common instances where meeting these requirements may jeopardize facility operational safety, create serious logistical issues, or pose an inordinate burden to comply. Compounding these problems for sources such as compressors at natural gas processing facilities is the reporting requirement which presents a compliance challenge. For some facilities, the three-year reporting cycle threatens to effectively impose a requirement for reporters to schedule a complete facility shutdown in order to collect data under the "not operating, depressurized" conditions.

Industry has proposed an alternative approach to EPA to gather reliable data for some emission sources while reducing the reporting burden. This approach would utilize existing measurement data, or embark on collecting such data, to develop new emission factors for estimating GHG emissions and eliminate the need for continued annual measurement programs. Industry suggests that measurements should no longer be required when adequate data are available to replace measurements with representative emission factor based estimates.

3.2 Understanding activity parameters

Activity parameters refer to counts of equipment or activities that produced GHG emissions.

The American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) conducted a collaborative survey of their members in 2011 to gather specific information on GHG emissions for onshore natural gas production operations, primarily focussed on activity data. API and ANGA postulated that EPA's current GHG emission estimates for the natural gas production segment were overstated due to invalid data for several key emission sources – including gas well completions and workovers, leakage from centrifugal compressors, and venting from pneumatic controllers. Two data requests were sent to members, tailored to focus on these emission sources and collect current information about industry practices. The actual data requests and the complete data analysis have been published in "Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production" [10].

3.2.1 Gas Well Completions

Gas well completions are important emission sources from natural gas production operations. As shown in Table 3, gas well completions with hydraulic fracturing comprise 10% of the total CH_4 emissions from petroleum and natural gas production operations.

The API/ANGA survey requested company information on the number of wells completed during 2010 and the first half of 2011. The survey collected data from over 20 companies representing 33 basins and over 91,000 gas wells. For gas well completions, data were collected for wells completed with and without hydraulic fracturing. The survey results for well completions are provided in Table 5. The API/ANGA results are compared to the 2010 and 2011 well completions data available from EPA, EIA, and with a commercial database of well completions information compiled by the CERA/IHS consultancy and provided to ANGA for this study.

Table 5. Comparative Summary of Gas Well Completions Data

	Completions without Hydraulic Fracturing		Completions with Hydraulic Fracturing		
	# Completions	% of Total	# Completions	% of Total	Total Completions
2010 EPA National Well Completions	702	14%	4,169	86%	4,871
2011 EPA National Well Completions	798	9%	8,077	91%	8,875
API/ANGA Survey Well Completions (2010 and 2011 data)[1]	540	7%	6,821	93%	7,361
Well Completions from CERA/IHS (2010 data)	7,178	39%	11,274	61%	18,452
Estimated well completions from EIA (2011 data) [11]	Not available		Not available		27,010[2]

[1] API/ANGA Survey data set represents a total of 91,000 wells distributed over a wide geographic area and operated by over 20 companies.
[2] The number of completions is estimated based on the difference in total gas wells from 2011 to 2010. However, EIA data shows a significant decrease in gas wells for Pennsylvania between 2009 and 2010 (from 57,356 wells to 44,500), with the 2011 well count (54,347) slightly less than 2009. API believes the 2010 well count for Pennsylvania is underestimated by about 13,000 wells, resulting in an overstatement of the wells completed for 2011.

The number of completions with hydraulic fracturing included in the national GHG inventory for 2011 seems to be underestimated (8,077 completions with hydraulic fracturing in 2011). In comparison, the API/ANGA survey obtained members' data for over 7,300 gas well completions (including 6,821 that were hydraulically fractured), where the survey represents just a portion of the industry. The CERA/IHS database reports over 18,000 completions with 11,274 completions with hydraulic fracturing for the year 2010 [10]. Even accounting for the difference in time periods (2011 for EPA compared to 2010 data from CERA/IHS), the national inventory appears to under-represent the number of well completions.

3.2.2 Pneumatic controllers

For pneumatic controllers in petroleum and natural gas production operations, methane emissions account for 9% and 8% of overall production emissions, respectively. The EPA national inventory does not currently track pneumatic controllers by controller type (high bleed, low bleed, and intermittent bleed) for natural gas production operations, though EPA does report counts of high-bleed and low-bleed controllers for petroleum production operations. The count of pneumatic devices by type for all production operations is being collected under 40 CFR 98 Subpart W starting in September 2012. Based on the distribution of the type of pneumatic controller and the default emission factors applied by EPA, this emission source could become more significant.

API conducted a separate survey to gather Subpart W data submitted by their members with the intent of analysing the information in preparation for EPA's public release of the data and comparing the data to emissions information reported by EPA in the national GHG inventory. API's survey gathered detailed emissions data reported for Subpart W and additional information to aid in the analysis.

The API survey included counts of pneumatic controllers by type for all production operations. Based on a total of 80 different reporting facilities, representing over 213,000 pneumatic controllers, the API survey resulted in a distribution of 13% high bleed, 46% low-bleed, and 41% intermittent bleed pneumatic controllers.

Pneumatic device emissions from the API survey contributed 39% of the total CO_2e emissions reported from the participating facilities. The emissions from pneumatic controllers are based on a count of controllers and default emission factors specified by EPA. The significance of emissions from this source justifies further research to improve our understanding of the relevance of the generic emission factors mandated by EPA to current operational practices.

3.3 Focus reporting on significant sources

In finalizing the rule language for Subpart W, EPA expanded reporting requirements for two emission source categories: flare stack emissions and dump valves on separators. Emissions from flare stacks and malfunctioning dump valves in onshore petroleum and natural gas production were not included in the original proposed rule for Subpart W. Industry believes emissions from these two sources are very small and do not justify the burden to gather the data.

3.3.1 Flare stack emissions

EPA’s addition of Flare Stack Emissions as a discrete source type in 98.232(c)(9) of the November 30, 2010 final rule represents a significant expansion of the rule requirements from the proposed rule. The proposed and final rule did include reporting of emissions from gas sent to flares from specific source types: dehydrator vents (98.233(e)); gas well venting during completions and workovers with and without hydraulic and non-hydraulic fracturing (98.233(g) and (h)); onshore production storage tanks (98.233(j)); well testing venting and flaring (98.233(l)); associated gas venting and flaring (98.233(m)); and centrifugal compressor venting (98.233(o)). For each of these sources, the applicable sections reference the method provided in 98.233(n) as the means for calculating emissions from flares.

Inclusion of flare stacks as a discrete source for onshore production in 40 CFR 98.232(c)(9) requires that operators establish systems to capture every flare event regardless of how small, estimate volume, calculate emissions, maintain records and report the voluminous information required by the rule.

API gathered data through a survey of member companies to quantify the emissions reported for discrete flare sources and document what flared streams contribute to these discrete sources. Based on member companies’ responses, flare stack emissions contribute 1% of the total production emissions from the 80 facilities that responded to the survey. As reported to API, these discrete flare sources consist of pilot gas, emergency flares, flash gas from heater treaters or other intermediate separation units, oil well flowbacks, and pneumatic pump vent gas. These are all very small gas streams, many of which are intermittent and are difficult to estimate the volume of gas flared. Therefore, inclusion of flares as a discrete source simply does not make sense from an emissions coverage versus burden and cost perspective.

3.3.2 Production tank dump valve emissions

Scrubber dump valves open periodically to reduce the accumulation of condensate liquids in scrubbers. EPA believes that malfunctioning scrubber dump valves contribute significantly to transmission storage tank emissions, and therefore included requirements for reporting emissions from this source in Subpart W [12].

The dump valves are also used in production operations on separators located before production storage tanks. In production operations, conditions can be detected through remote monitoring that may indicate that a dump valve is not functioning properly, such as a sudden pressure drop, a low level in the separator, or an increase in the amount of fluid in the tank. These leaking valves are also audible and are generally located at sites that are routinely visited. In addition, the emissions from stuck dump valves in production would be much lower than stuck dump valves in transmission systems because transmission systems operate at much higher pressures than the separators upstream from onshore production storage tanks. No reports or studies have been conducted showing that scrubber dump valves are a large source of emissions from the onshore production sector. However, the November 30, 2010 final rule for Subpart W extended the requirements for reporting stuck dump valve emissions from transmission to onshore production operations.

Industry information indicates that there are very few occurrences of stuck dump valves on production storage tanks. API's survey to gather data reported to EPA for Subpart W was analysed to determine the contribution of emissions from stuck dump valves. Of the 80 facility reports collected through the API survey, scrubber dump valve emissions were only applicable and therefore reported for 7 facilities. The total vented GHG emissions from scrubber dump valves represented only 0.1% of the emissions reported by the participating companies.

3.4 Data collection and management

A key challenge for onshore petroleum and gas operators in the first GHG reporting cycle was developing emissions information and maintaining the large volume of data required for reporting while the rule and reporting tools were undergoing revisions. During 2011 and 2012, while companies were developing systems to comply with the reporting rule and gathering data for the first reporting cycle, EPA proposed and finalized the following amendments:

- Revisions to BAMM provisions – Final Rule (09/27/11)
- 2011 Technical Revisions and Clarifications – Final Rule (12/23/11)
- 2012 Technical Corrections and Clarifications – Final Rule (08/24/12). This amendment was finalized just weeks before the end of September 2012 reporting deadline.

EPA also developed reporting forms and XML schema for the nineteen source categories associated with onshore petroleum and natural gas facilities. These were first available for reporters to test in April 2012, with final versions available in mid-August. Due to the timing issues in aligning a reporter's data system to EPA's reporting format, many of the Subpart W reporters relied on EPA's spreadsheet-based reporting forms rather than the XML schema.

4. Conclusions

The petroleum and natural gas industry has been working to improve the emissions data attributable to the industry sector, and in particular for production operations. Emissions data collected for Subpart W – Petroleum and Natural Gas Systems was reported to EPA for the first time in September 2012. For this first reporting year a significant amount of the data reported for this sector relied on the use of best available monitoring methods. It is expected that with each year of subsequent reporting to the GHGRP, the estimation methods and emission factors will improve. Over time, information from the regulatory reporting program will provide more complete and accurate data, and should improve EPA's national GHG emission estimates. Based on information collected through industry member surveys, emission estimation improvements may be warranted for gas well completions and workovers, pneumatic controllers, and fugitive emissions.

A key message from GHG reporting experiences by onshore petroleum and natural gas companies in the U.S. is the need for balancing reliable data and reporting burden. Emissions data reported through Subpart W may be useful for demonstrating that the insignificant emissions contribution from sources such as flare stacks and production tank dump valve compared to the level of effort to gather the required reporting information supports exclusion of these sources from ongoing reporting.

The petroleum and natural gas industry is committed to working with the EPA to make use of the data collected through industry surveys to increase public confidence in the emission estimates for the industry, and thereby to contribute to informing future policy.

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6. Acknowledgements

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7. Biography

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