

February 6, 2009

Tom Moore  
Coordinator, Western Regional Air Partnership (WRAP)  
Air Quality Program Manager, Western Governors' Association  
c/o Cooperative Institute for Research in the Atmosphere  
Colorado State University  
1375 Campus Delivery  
Fort Collins, CO 80523-1375  
Phone: (970) 491-8837  
Fax: (970) 491-8598

Re: Oil & Gas Greenhouse Gas Emissions Accounting Protocol  
Task 1: Background and Scoping Paper

Dear Mr. Moore,

The Natural Resource Defense Council (NRDC), Western Environmental Law Center, and Wild Earth Guardians appreciate the opportunity to work with the Western Regional Air Partnership (WRAP) and the Western Governors' Association (WGA) to develop the Oil & Gas Greenhouse Gas Emissions (GHG) Accounting Protocol.

On January 23, 2009 the WRAP circulated the Task 1 draft paper for the Oil & Gas Greenhouse Gas Emissions Accounting Protocol Project, entitled *Development of Scoping Paper for the Oil and Gas Industry*. This paper will be discussed in greater detail at the February 12-13, 2009 meeting in Santa Fe, New Mexico; however, this letter responds to your request for input prior to the meeting.

Overall, the draft Task 1 document reflects a tremendous amount of effort and expertise, and we appreciate the opportunity to provide our comments on this early draft.

Our main concerns on this report are summarized below, followed by detailed comments by chapter.

1. Scope, boundary, and definitions need further refinement;
2. Further work is needed to ensure all emission sources are included;
3. Site specific testing, vendor data, and monitoring data already required for permitted sources should be used rather than generic emission estimating methods;
4. A better understanding of permitted vs. un-permitted source data availability is needed to identify data that is already available for emission computations. The most accurate, detailed data sources should be used;

5. Where data is insufficient, recommendations should be made to put the necessary data collection and tracking systems in place. Current data availability should not constrain high quality protocol development;
6. Operators are in the best position to compute accurate GHG emissions at an Exploration Prospect and Operating Field level. Operators should provide GHG emission estimates to the Owner Companies. The Owner Companies should report emissions based on owner interest;
7. Contractor emissions must be included due to the large amount of outsourcing used in the oil and gas industry. Operators can compel contractors to provide data via the sub-contract;
8. A single rigorous protocol should be developed. We do not support separate methods for voluntary and mandatory reporting;
9. Flaring, contractor, and small combustion device emissions should not be excluded from the 95% threshold for rigorous emission estimation techniques; and
10. More information is needed on how the public will be involved in protocol development.

---

## **Chapter 1: Introduction**

---

**Scope:** The Chapter 1 scope of work stated it would: “[p]rovide overviews of the O&G E&P and gas processing sectors in North America and within the jurisdictions of the Western Climate Initiative.” Chapter 1, as currently drafted, provides a good overview of the Western States, but does not provide a consistent overview of Oil and Gas (O&G) and Exploration and Production (E&P) and gas processing sectors in North America. Canadian oil sands and coal bed methane operations are included, but the report is silent on all other Canadian O&G operations. Mexico is briefly included. Major oil and gas producers such as Alaska and the Gulf Coast are not included, nor are East Coast operations.

It would be useful to clarify up front that the primary focus and goal of this work effort is to develop an Oil & Gas Greenhouse Gas Emissions Accounting Protocol that will work successfully for the Western States. Secondly, all other North American O&G operations can be briefly mentioned (including Alaska, Gulf Coast, East Coast, Canada and Mexico), noting that the work developed for the Western States may be applicable to these other North American locations. However, if it is the intent of this project to more extensively include Canadian O&G operations, all Canadian operations should be included not just oil sands and coal bed methane.

The current draft disproportionately covers Canada’s oil sands and Canadian operations, while remaining silent on Alaska and the Gulf of Mexico. Alaska has similar oil sands that may warrant balanced coverage. The Gulf of Mexico, the largest O&G producing area in the United States, gets little mention.

Statements like “onshore and offshore oil and natural gas systems encompass hundreds of thousands of individual wells....throughout the Western US, parts of Mexico and Canada” (p.28) are confusing. Onshore and offshore O&G operations in North America are not limited to the Western US, parts of Mexico and Canada; however, the scope of this report may be.

**Western States Definition:** Please define the term Western States or Western US for consistent use throughout the document. It is our understanding that WRAP has defined “Western States”, for the purpose of this project, to include all onshore and offshore O&G in the following states: California, New Mexico, Washington, Oregon, Montana, Idaho, Wyoming, North Dakota, South Dakota, Nebraska,

Kansas, Oklahoma, Colorado, Utah, Arizona, and Nevada. This definition excludes the western state of Alaska. However, some statistics and figures in this draft do not adhere to this definition. For example:

- Figure 5 defines “Western US” is defined as “offshore production in California, Alaska and the Federal offshore PADD 5 area;”
- Figure 1 defines “Western US” as: North and South Dakota, Nebraska, Kansas, and Oklahoma, and all states to the west, excluding Texas. However, this definition does not exclude Alaska which is also a state to the west; and

Figure 12, a map of the Western States, is excellent and should be moved to Chapter 1; however, Figure 15 does not include the Western States of Nebraska, Kansas, and Oklahoma.

**Facility Scope Definition:** The report would benefit from the addition of a clear and concise definition of the O&G facilities scope under study. Please define the term “Oil & Gas Exploration, Production, Gathering & Processing” to clarify the facilities included in the protocol. We recommend the protocol start at the well and end at the inlet valve of an oil refinery or inlet valve to a gas distribution system. Additionally, the draft protocol includes both onshore and offshore sources but is not consistent on this point. The WGA, WCI, and TCR all have onshore and offshore responsibilities, thus is logical to include both in the protocol. To summarize, we recommend the definition read:

*For the purposes of this protocol, Oil & Gas Exploration, Production, Gathering & Processing is defined as all onshore and offshore, direct and indirect equipment and facilities used to explore for oil and gas, and produce, gather and process oil and gas from the wellhead to the inlet valve at an oil refinery or the inlet valve at a gas distribution system.*

We also recommend use of the definitions agreed upon by the TCR members and adopted in the document entitled, “General Reporting Protocol for Accurate, Transparent, and Consistent Measurement of Greenhouse Gases Across North America,” issued by TCR in May 2008. Since the ultimate goal is to develop a protocol that will be adopted by TCR, consistency with TCR definitions will streamline the adoption process.

**Production Statistics:** Please review the production statistics for consistency. For example:

- In most cases, onshore and offshore statistics are included, but not in every case. Please document statistics to indicate when offshore production is excluded.
- Please use consistent English units throughout the paper so the reader can compare and contrast US statistics with Canadian and Mexican statistics.
- Oil production statistics shown in Figures 16 and 17 are not consistent with Table 6 and Figure 1.

**Figures 3&4:** Figures 3 and 4 are excellent, and provide clarity in defining scope starting and ending points. However, the first block in each figure should be revised to show that the first step in the process is “exploration.” Exploration entails seismic operations, geologic and geophysical surveys, and exploratory drilling. The Figure 3 production block should be revised to include a well label. Wellheads can include pump-jacks, but this is not always the case.

**Recovery Factors:** Please revise recovery factor estimates to ensure consistency throughout the document. Primary recovery factor estimates of 25% are shown on p.4, but are stated as 10% on p.5. Secondary recovery estimates for water and gas injection are listed at 20-40% at the top of p.5, but water injection is later cited at an 80% recovery on p.5.

**NGL Processing:** On p.7, please add cryogenic processes to the list of techniques for Natural Gas Liquid (NGL) recovery.

**Drilling Rig Cost and Service Life:** On p.9, drilling rig costs are cited at \$20MM, yet rig costs can vary widely depending on well complexity and depth. It is not common for rigs to be “torn down and completely refurbished every few years.” This is an important clarification because aging rigs typically have less efficient equipment and higher GHG emissions.

**O&G Production Investment:** Successfully locating oil and gas (p.9) is only one aspect in determining whether O&G reserves will be produced. Alternative corporate investment options are the main factor in determining whether one field is produced before another. The highest profit fields will be prioritized for investment. Higher profitability areas are the most likely areas for attention when considering GHG emission generation and reduction targets.

**Suspended Wells:** In addition to plugging and abandoning or producing a well (p.10), a well can be suspended until additional appraisal wells are drilled or the field becomes economic to produce. Historically, suspended wells have been sources of GHG emissions, due to unattended leaks and should be included.

**Offshore Drilling and Production:** The offshore rig types listed on p.13 do not include all the offshore rig types used in North America. Drilling can also occur from drill ships, natural barrier islands, or man-made islands. In Canada and Alaska, Concrete Drilling Island Structures (CIDS) and Single-Steel Drilling Caisson (SSDC) are built for ice conditions. Offshore exploration drilling and production facility types vary widely and emit significantly different amounts of GHG emissions. If the scope is limited to the Western States, offshore exploration drilling and production studies should mirror California operations. If the scope is expanded to cover North America, more work is needed in this section.

**Seismic:** Onshore and offshore seismic is conducted at the exploration and production stages. Both emissions for seismic exploration and seismic operations used to further delineate a producing field (e.g., 3D focused surveys) should be included.

**Oil Sands:** The report describes Canada’s extensive oil sand deposits, but is silent on America’s vast resources of oil sands in the most western state. Alaska contains over 20 billion barrels of heavy oil in shallow sand reservoirs. BP is using Cold Heavy Oil Production with Sand (CHOPs) technology to recover it.

---

## **Chapter 2: Emission Sources**

---

**Boundary:** In order to clarify the scope in Chapter 1, please consolidate the boundary information in Chapter 1, rather than including boundary information in Chapter 2.

**GHG Emissions by Source:** Listing GHG emission by source types is effective. However, some Chapter 1 information is duplicated in Chapter 2 and is not always consistent. Please consolidate all emission data by source in Chapter 2 to reduce redundancy, leaving Chapter 1 to define the scope and provide a basic introduction to the O&G industry.

**Table 1: O&G Exploration:** Please add the following GHG emissions sources:

- Onshore seismic units (offshore seismic is listed);

- Offshore supply/fuel support vessels and tugs;
- Flares;
- Waste incinerators;
- Geophysical and geological (G&G) site clearance and borehole drilling;
- Fuel storage tanks;
- Chemical tanks;
- Flowback tanks (crude oil, acid and frac fluid);
- Crane engines;
- Heaters and boilers;
- Fire water pumps/engines;
- Spill response equipment (pumps, engines, vehicles, vessels, atehy wagons, etc.);
- Pumps and engines (cement, mud, chemicals);
- Direct vents (normal operations and maintenance and safety blowdowns) and PSVs;
- Some mobile sources, but not all are listed in Table 1. A more comprehensive list is provided in Table 5. Remove mobile sources from Table 1 and add any that are missing to Table 5. Clarify that O&G exploration sources include Table 1 and Table 5 equipment;
- All equipment associated with construction activities (site clearing, pad, island, road construction, etc.);
- Drilling rig and contractor camp engines and heaters;
- Mud, frac fluids and waste water treatment tanks and pits; and
- Wellwork (wireline and electric line logging, stimulation treatments, etc.).

**Table 2: O&G Production:** Please add the following GHG emissions sources:

- Well drilling and completion activities will continue into production. Please add all the sources associated with well drilling and completion activities in Table 1 (and recommended above) to Table 2;
- Fuel and crude oil storage tanks (these tanks are not always located at the wellhead; they can be located at the processing facility);
- Fugitive emissions (all operations – not just at the oil well). Fugitive emissions at the processing plant and from other O&G equipment can be significant;
- Crude oil separation system tanks and pressure vessels;
- Chemical tanks;
- Flowback tanks (crude oil, acid and frac fluid);
- Power plant turbines can be onshore, as well as offshore;
- Wastewater treatment facilities;
- Water and gas re-injection pumps/engines/compressors (seawater/freshwater/dry gas/miscible gas/gaslift, etc.);
- Artificial lift (gas lift, pumpjacks, subsurface pump systems, etc.);
- Heaters and boilers should be expanded beyond the well to include processing facility equipment (building heat, fuel gas heaters, reboilers, free-water knockout, etc.);
- Fire water pumps/engines;
- Direct vents (normal operations and maintenance and safety blowdowns) and PSVs;
- Onshore and offshore seismic units (seismic activity can extend beyond exploration into production; more frequently operators are collecting 3D focused seismic to improve reservoir management);
- Offshore supply/fuel support vessels and tugs;
- Flares;
- Waste incinerators;

- Crane engines;
- Spill response equipment (pumps, engines, vehicles, vessels, atthey wagons, etc.);
- Pumps and engines (cement, mud, chemicals);
- Vessel loading, unloading and shore-side storage facilities;
- Tanker transportation (or does the scope of this project end at exit valve at platform?);
- NGL units;
- Some mobile sources, but not all are listed in Table 2. A more comprehensive list is provided in Table 5. Remove mobile sources from Table 2 and add any that are missing to Table 5. Document that O&G production sources includes Table 2 and Table 5 equipment;
- All equipment associated with construction activities (site clearing, pads, road, facility, docks, offshore islands and pipeline construction, etc.);
- Drilling rig and contractor camp engines and heaters; and
- Wellwork (maintenance, repair, wireline and electric line logging, stimulation treatments, etc.).

**Table 3: Gas Production:** Please add the following GHG emissions sources:

- Well drilling and completion activities will continue into production. Please add all the sources associated with well drilling and completion activities in Table 1 and 2 (recommended above) to Table 3;
- Fuel storage tanks;
- Fugitive emissions (all operations – not just at the well). Fugitive emissions at the processing plant and from other equipment can be significant;
- Chemical tanks;
- Flowback tanks (acid and frac fluid);
- Power plant turbines can be onshore, as well as offshore;
- Wastewater treatment facilities;
- Re-injection pumps/engines/compressors;
- Fire water pumps/engines;
- Direct vents (normal operations and maintenance and safety blowdowns) and PSVs;
- Onshore and offshore seismic units (seismic activity can extend beyond exploration into production; more frequently operators are collecting 3D focused seismic to improve reservoir management);
- Offshore supply/fuel support vessels and tugs;
- Flares;
- Waste incinerators;
- Crane engines;
- Spill response equipment (pumps, engines, vehicles, vessels, atthey wagons, etc.);
- Pumps and engines (cement, mud, chemicals);
- Vessel loading, unloading and shore-side storage facilities- (e.g., LNG);
- Tanker transportation (or does the scope of this project end at exit valve at platform?);
- Drilling rig and contractor camp engines and heaters;
- All equipment associated with construction activities (site clearing, pads, road, facility, docks, offshore islands and pipeline construction, etc.).
- Wellwork (maintenance, repair, wireline and electric line logging, stimulation treatments, etc.);

**Table 5: O&G Mobile Sources:** Consolidate all mobile sources from Tables 1-4, as well as those listed in Table 5, to create a complete, consistent list of mobile sources. Please add:

- Planes (helicopters are listed, but not fixed wing passenger and cargo planes); and
- Supply boats, barges and tugs.

**Construction:** On p. 41, well pad construction was identified as a source of emissions; however, this category should be expanded to include all construction activities associated with oil and gas operations (e.g., roads, facilities, island, docks, pipelines, etc.).

**Power Generation & Boilers:** In addition to compression, internal combustion engines and turbines also provide power to O&G facilities. In the process, they also produced substantial GHG emissions. Boilers may also be used for building heat.

**Process Diagrams:** Figures 9 &10 are excellent. Please add additional process diagrams and label GHG emissions sources similar to Figure 10.

**Pumps/Engines:** Page 32 describes salt water disposal engines, but does not include pumps and engines used for drilling muds and cements, or well stimulation (acid treatments, fracs, etc.) or grind and inject disposal waste disposal facilities (often called CRI).

**VRU:** Vapor Recovery Units (VRU) emissions can also be routed to a flare, generating GHG emissions.

**Flaring:** Flaring efficiency data reported on p.33 is inconsistent and dated. Flare efficiency will depend on flare age, design, gas composition and operating conditions. Typically, 98-99% efficiency should be achieved with proper design and operation.

**Oil Tanks:** Floating roofs should be added as an emission control technique to p.36.

**Pits:** Please add drilling mud, frac fluids and waste water treatment tanks and pits to p.39.

**Rig Fuel Type:** Drilling rigs have been constructed using highline electric power or fuel gas as the primary power source, to reduce emissions. They are not always constructed as diesel fired units with a later conversion to gas.

**Permitted Sources:** For the list of sources identified in Chapter 2, it would be useful to identify which sources are already included within an air permit. Permit reporting and record keeping requirements already in place will improve GHG emission estimate accuracy, and streamline reporting requirements. Later in Chapter 6, the paper discusses the challenges in obtaining operating, fuel and other emission estimating data for some sources, especially contractor emissions. However many emission sources are already subject to permit recordkeeping and reporting requirements that streamlines the process.

---

### **Chapter 3: Regional Variations**

---

**Western State Data Parity:** Chapter 3 provides more in-depth coverage of California. Should equivalent data be provided for the other states?

**Figure 14:** This figure includes 1995 data (over 13 years old). Please provide more current data.

**Tables 6 & 7:** Do these tables include offshore production?

**Figure 15:** Add Western States of Nebraska, Kansas and Oklahoma for consistency.

**Table 8:** Western States definition in footnote conflicts with Chapter 1 definition.

**CBM:** Coal bed methane emission sources (p.55) should be included in gas production emission sources in Chapter 2.

**Table 9:** Use English units consistent with the rest of the paper.

---

## **Chapter 4: Emission Estimating Methods**

---

**Site Specific Testing, Vendor Data, and Monitoring:** For all emission sources, site-specific testing, vendor data, continuous emission monitoring systems (CEMS) and parametric emission monitoring systems (PEMS) will provide the most accurate emission estimate. These methods should be listed as the highest-ranked emission estimating method, with alternative emission estimating methods and algorithms ranked as lower quality estimates. Primary use of lower quality top-down methods is not recommended when more accurate emission methods are available to an Operator. Alternatively, if this information or equipment is not available, alternative estimating methods should be considered.

**Permitted Sources:** A better understanding of permitted vs. un-permitted source data availability is needed to identify data that is already available for emission computations. The most accurate, detailed data sources should be used. Several of the recommended methodologies rely on operating hour, fuel and other operational data that may readily be available because of existing air permitting recordkeeping and reporting requirements. Chapter 2 GHG emission sources should be segregated into two categories: (1) emission sources typically included in a government air permit that require testing, emission monitoring or recordkeeping requirements, and (2) emission sources that are not typically included in an air permit. This will assist in identifying the data input available for emission computations.

For example, most large O&G turbines are required to obtain an air permit. Due to turbine cost and emission volume, most turbines have vendor data, and many have source test data. As part of that permit, a typical minimum record keeping and reporting standard would include fuel use and operating hours. Depending on location, emission monitoring or control systems may be required. Therefore, for turbines, it would make the most sense to use more accurate, site specific data as the primary emission estimating method. This same rationale applies to many O&G emission sources.

A more rigorous analysis is needed to identify data sources for smaller emission units that are currently below permitting and reporting thresholds. We should not conclude that just because no one is currently collecting data on these smaller sources, that it is not a good idea to do so in the future. We remain concerned that small emission sources can result in large cumulative sources of GHG emissions. If there are not sufficient data collection and tracking systems in place to collect the data needed to estimate GHG emissions from small sources, we need to identify the systems needed and put them in place. We should not use current data availability as a constraint in protocol development. A high quality protocol will examine what data is available **and** make recommendations for additional data collection systems to improve GHG emissions reporting accuracy.

**AP-42:** Methods using EPA's AP-42 emission factors should be ranked on the quality of the data used to develop the AP-42 algorithm. The AP-42 documents provide guidance on data quality.

**EPA Methods:** EPA methods are available for flares, boilers and heaters and several other sources listed in Table 11.

---

## Chapter 5: Boundary Issues

---

To avoid double counting GHG emissions and avoid excluding small, but cumulatively large sources of emissions, we recommend that emissions be computed by the Operator, and be reported by Owner Company.

In every O&G exploration and production activity, there is an Operator. That Operator runs the physical field operations, obtains the permits and hires the subcontractors. The Operator is the most logical party to develop an accurate GHG emission computation. The Operator can establish GHG or data reporting requirements in its subcontracts to ensure that contractor emissions are accurately reflected. The Operator can compute the emissions and provide that data to the Owner Companies. The Owner Companies can report the data based on its owner interest.

For example Company A, B, and C each own 1/3 of an O&G operation. Company A is the Operator. Company A estimates 100 units of GHG emissions and provides that information to the Owner Companies. The Owner Companies A, B, and C each report 33-1/3 units of GHG emissions. This places the burden of GHG emission computations on the Operator, which has the best available information and expertise to compute the emissions. It also places the reporting burden on the owners, which avoids double counting emissions.

We agree GHG emissions from contract operations are significant and must be included in the GHG protocol. O&G companies extensively out-source work to subcontractors, including major emission sources such as drilling rigs, workovers, construction, logistical operations, and other specialty services. We fully support including contractor emissions in the GHG emission estimates, and fully support your recommendation to make that clear in both the WRAP and The Climate Registry (TCR) reporting requirements for E&P activities.

Operators are in a position to make GHG emission reporting (or the data needed for the operator to compute contractor GHG emissions) a requirement of the subcontract. Contractors often have reporting obligations to the Operator. We do not understand why contractors would be unwilling to provide the Operators (their client) with the data needed to accurately compute GHG emissions as suggested on pages 108-111. Contractors typically track fuel and operating hours for billing purposes. Tracking systems can be expanded and improved, if compelled by the Operator's contract requirements. Contracts can include confidentiality provisions. If mandatory contractor reporting is required by the government, then contractors will be motivated to comply to obtain contract opportunities.

**Single Protocol Development:** The draft refers to “*voluntary protocol*” and “*mandatory protocol*” development. In our previous comments, we have recommended, and continue to recommend that a single reporting protocol be developed to provide a consistent reporting methodology for all reporting. Our main concern is that a mix of voluntary and mandatory reporting will occur and then later be used as the basis for a cap-and-trade program. GHG emission cap-and-trade programs must rely on rigorous mandatory reporting of GHG emissions. We do not support less accurate “voluntary protocols” being used for cap-and-trade programs, and as such do not see the benefit of establishing a separate voluntary protocol system.

---

## Chapter 6: TCR Reporting Issues

---

**Contractor Emissions:** We agree with your recommendation that drilling rig and workover unit contractor emissions should be reported to the Operator and included. However, we recommend that all contractor emissions be reported. In addition to drilling rig and workover unit contractors, there are other categories of E&P emission sources that are often subcontracted out that warrant consideration. Some of these categories include:

- Wellwork (maintenance, repair, wireline and electric line logging, stimulation treatments, etc.);
- Seismic Operations;
- Offshore supply/fuel support vessels and tugs;
- Construction equipment and other mobile sources;
- Geophysical and geological (G&G) site clearance and borehole drilling; and
- Spill response equipment (pumps, engines, vehicles, vessels, atthey wagons, etc.).

**5% Limits on Simplified Methods:** We recommend that further work be completed as part of Task 2 to determine which O&G E&P emission sources are most appropriate for inclusion in the 5% simplified emission estimating method category. As described in our comments on Chapter 4, more work is needed to define source data accuracy. We agree that 95% of the emission total should be based on a rigorous emission estimating method, as required by The Climate Registry (TCR), and that 5% of the total emissions may require simplified emission methods. We agree that Operators should be given some flexibility in determining which sources fit the 5% category, but recommend SAIC provide guidance on this issue after more detailed work is completed (in Task 2 of this project). A large number of small emission sources can result in a large amount of GHG emissions and warrants careful consideration.

However, it is pre-mature to make the recommendation to exempt flaring, all contractor emissions, and small combustion devices from the 95% threshold (p.109). Sources should not be automatically exempted from accurate emission estimating just because there are not currently GRP-approved methods. Rather, Task 2 project work should assist in identifying methods that could be considered for inclusion. If we understand your recommendation correctly, this could result in substantially more than 5% of the total E&P GHG emissions to be based on very simplified methods. At this point, we are not convinced that the Operator cannot obtain vendor data, or contractor data to improve the estimate quality. This recommendation is inconsistent with TCR's goal of limiting simplified methods to less than 5% of the total. More work is needed on this topic.

**Reporting Trends:** If contractor emission data is absent, E&P reporting will be missing a large amount of GHG emission data. This will result in inconsistent data reported by Owner Companies, based on the amount of out-sourcing their Operator employs from year to year. Base year and future emission estimates will vary widely as contracting strategy changes. For this reason, all contractor emission estimates must be included.

**Flaring:** We agree that computing flare emissions requires good quality data and technical expertise. We also agree that due to the wide variety of flare types and aged systems, there will not be a "one-sized-fits-all" method. However, we do not agree that there are no accepted approaches to compute flare emissions (p.109). To develop accurate flare emission estimates, vendor and site specific data is needed. GHG emissions from flares can be significant. Operators should be required to develop accurate site specific flare methods based on vendor data and site specific information.

**Aggregation:** Consistent with our comments for Chapter 5, we recommend emissions be aggregated at the Operator level. Exploration Operators should compute total Exploration Prospect emissions. Production Operators should compute total Operating Field emissions. Exploration Operators and Production Operators should be responsible for computing emissions and providing that data to Owner Companies to report.

More specifically, if an Exploration Operator is running seismic and drilling three wells to explore the Prospect “A” potential, those emissions should be combined under the title Prospect “A” GHG emissions. Prospect “A” emissions would, in turn, be provided by the Exploration Operator to the Owner Companies that invested in the exploration program. Owner companies would report their share of aggregated emissions.

Similarly, we recommend Production Operators aggregate all emissions required to produce O&G at an Operating Field level. For example, Field “A” GHG emissions would include all sources required to produce the field’s O&G reserves (from the wellhead to the outlet valve of a processing plant, including all support facilities and contractor emissions). Most Operators capture data at a Prospect or Operating Field level for cost and profit tracking purposes. Aggregation of emissions at this level is logical and consistent with commonly accepted O&G accounting methods.

This draft does not accurately reflect EPA’s definition of a stationary source or aggregation required by the Clean Air Act.

We do not agree with the recommendation on p. 116 that suggests E&P reporting should “*encourage*” aggregation of emissions rather than require it. We are equally concerned about using aggregation methods that focus only on aggregating large source emissions, while ignoring small emission sources. In our previous comments, we consistently raised the concern that exclusion of small emission sources will ignore cumulatively large source of emissions. We reiterate our recommendation that the protocol should aggregate **all** emission sources. Emissions should be aggregated by the Operator at an Exploration Prospect or Operating Field Level and be reported by the Owner Companies based on their proportional ownership share.

---

## **Chapter 7: Verification Issues Specific to O&G Operations**

---

**Contractor Emission Verification:** We agree that contractor emissions should be included in the E&P sector verification protocols.

**Conflict of Interest:** We agree that additional work should be completed in Task 3 ensure emission verification systems avoid conflict of interest.

---

### **Overall:**

---

**Acronym List:** Please add an acronym list and spell out the acronym the first time used in each Chapter.

**Redundancy:** Combine information whenever possible, to reduce redundancy. For example, the information on pages 3 and 5 is redundant with Chapter 2. Some information in Chapter 3 repeats information covered in Chapter 2.

**Chapter Subsections:** Assign subsections within a chapter table of content reference numbers (e.g. Section 1.1 = Chapter 1, Section 1, etc.). This allows section referencing to reduce redundancy. And

makes referencing more efficient for the reader, rather than “see above”, “as noted previous” or “see Chapter 4”. A specific section number will lead the reader directly to the referenced section.

**Public Involvement:** The approved project scope includes a Protocol Advisory Group (PAG) to allow the public to participate in protocol development. In our previous comments, we raised concern that it was not clear how the public will be informed and asked to participate in protocol development. The Task 1 report is silent on how protocol information will be public noticed, and included by the Steering Committee and contractor. Please include a description of this process or explain how this concern will be addressed in Task 2.

Please contact Tom Singer at (505) 989-7925 or Jeremy Nichols at (303) 454-3370 if you have any questions on our recommendations.

Tom Singer  
National Resource Defense Council

Jeremy Nichols  
Wild Earth Guardians

Erik Schlenker-Goodrich  
Western Environmental Law Center

File: WRAP O&G GHG Protocol Development 2008-2009