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Evaluation of Oil and Gas Sector Greenhouse Gas Emissions Estimation and Reporting

CONSULTANT REPORT (FINAL DRAFT)

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Evaluation of Oil and Gas Sector Greenhouse Gas Emissions Estimation and Reporting ***(FINAL DRAFT)***

Work Authorization Number 3-4: Evaluation of Oil and Gas Sector Greenhouse Gas Emissions Estimation and Reporting

Report to
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Forward

In support of industry-specific protocol development at the California Climate Action Registry (CCAR), the California Energy Commission requested TIAX LLC and its subcontractor ICF Consulting to critically review IPIECA's[1] *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions* and API's[2] *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry.* Specifically, TIAX and ICF were asked to determine the applicability of these documents to California's oil and gas industries, and evaluate their consistency with the CCAR's General Reporting and Certification Protocols.

The IPIECA document provides reporting protocol guidelines and is largely based on the 2004 edition of the WRI/WBCSD[3] Greenhouse Gas Reporting Protocol. Therefore, comparisons made are essentially between the WRI/WBCSD protocol and the CCAR general reporting and certification protocols. The IPIECA guidance document is intended as a companion report to the API compendium document which is a compilation of emission quantification techniques.

TIAX was tasked with reviewing the IPIECA guidelines while ICF reviewed the API Compendium. Separate draft reports of these reviews were distributed to stakeholders for feedback. Specific comments have been incorporated and the individual reports are combined into this single document. Part 1 provides the TIAX review of the IPIECA guidelines and Part 2 provides the ICF review of the API compendium.

[1] International Petroleum Industry Environmental Conservation Association

[2] American Petroleum Institute

[3] World Resources Institute / World Business Council for Sustainable Development

Part 1

Review of the IPIECA Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions

Work Authorization Number 3-4: Evaluation of Oil and Gas Sector Greenhouse Gas Emissions Estimation and Reporting

Prepared by TIAX LLC

TIAX Innovation since 1886

1. Introduction

The California Climate Action Registry (CCAR) intends to develop a greenhouse gas (GHG) emissions protocol for California's oil and gas industries. As directed by SB 527 (Chapter 769, Statutes of 2001), the California Energy Commission provides assistance to the CCAR in development of protocols to quantify, report and certify GHG emissions for use by its participants. In support of the upcoming oil and gas industry-specific protocol development effort, TIAX LLC has been requested to critically review IPIECA's *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions*[4], determine its applicability to California's oil and gas industries, and evaluate its consistency with the CCAR's General Reporting and Certification Protocols.[5,6]

The CCAR's General Reporting Protocol and Certification Protocol are referred to in this report as the "CCAR Protocols." The IPIECA petroleum industry guidance document is referred to as the "IPIECA document." The IPIECA document is largely based on the 2004 edition of the WRI/WBCSD Greenhouse Gas Protocol.[7] In fact, much of the material in the IPIECA document was taken directly from the original and revised WRI/WBCSD protocols and supplemented with petroleum industry information.

The IPIECA document is intended to be a companion document to the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry,* published in 2001. Similarly, this TIAX review is intended to be a companion document to a separate review of the API Compendium prepared by ICF Consulting. As a result, this report focuses on the accounting and reporting of GHG emissions at the corporate or industry entity level, while the ICF report focuses on emission quantification methodologies.

While reading this document it is important to keep in mind that the IPIECA document is not a reporting protocol for a specific program. Rather, it is intended as an overarching set of guidelines for entities to use in their efforts to comply with reporting protocols of the various programs it may choose or be required to participate in. As such, the IPIECA document *advises* and *encourages* reporting entities, but does not *require* actions in the manner of the CCAR protocols, which were written specifically for reporting to the California Climate Action Registry.

Before reviewing the GHG reporting and certification issues, a brief description of California's oil and gas industries is provided in Section 2. Section 3 provides an issue by issue comparison of the guidance in the IPIECA document to the CCAR protocols.

[4] *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions*, December 2003, International Petroleum Industry Environmental Conservation Association."

[5] California Climate Action Registry, General Reporting Protocol Version 2.0, October 2003.

[6] California Climate Action Registry, Certification Protocol, Version 2, July 2003.

[7] *A Corporate Accounting and Reporting Standard*, Revised Edition (2004) WRI/WBCSD.

2. Background — California's Oil and Gas Industries

The oil and gas industries may be broken down into a number of sub-sectors ranging from exploration to retail sales. With the exception of exploration activities and oil wells producing associated natural gas, the oil and gas industries are two distinct industries with very different emission sources and business structures. While the CCAR requires reporting of all material California emission sources, reporting of GHG emissions from US and worldwide operations is encouraged. Therefore, the upcoming CCAR oil and gas protocols must be sufficiently comprehensive to cover emission sources from industry operations regardless of geographical location. This section provides some background information on GHG emission producing activities from oil and gas industry operations in California. As will be seen, all sub-sectors of the oil and gas industries are represented within California.

2.1 Natural Gas Industry

The natural gas industry can be divided into the following GHG emission producing activities:

- Exploration and production
- Field gathering and pipeline transport to processing plant
- Natural gas processing
- Pipeline transport to storage/distribution
- Storage
- LNG imports (receiving and re-gasification terminals)
- Pipeline distribution to end-users

California currently produces approximately 15 percent of the natural gas consumed in the state. In-state production peaked in 1985 at approximately 7 trillion cubic feet and subsequently reached a historic low of 290 billion cubic feet in 1996. Production in recent years has been in the 350 billion cubic feet range. While peak California production levels are not expected to return, in-state production is an on-going activity with 1200 producing wells. Most (75%) of the in-state natural gas comes from Southern California and is associated gas (comes from a crude oil well) while the balance is non-associated gas produced in Northern California from large gas fields.

Before the produced raw gas is sent to a nearby processing plant through gathering pipelines, the oil and condensates (including water) are removed at the wellhead. At the processing plant, the gas is transformed into pipeline quality natural gas. The process includes: dehydration (removing water vapor in solution), separation of natural gas liquids (NGLs – a valuable hydrocarbon byproduct), and removal of sulfur and

carbon dioxide. From the processing plant, the gas enters the transmission pipeline system and flows to storage fields or through distribution pipelines to the end user.

Because only 15 percent of the natural gas consumed in California is produced in-state, the dominant natural gas industry activities are transmission, storage and distribution to end users. Most of the natural gas consumed in California is imported from the Rocky Mountains, Southwestern states, and Canada via the interstate natural gas pipeline system. Five pipelines make up the interstate system: Gas Transmission Northwest Pipeline, Kern River Pipeline, Transwestern Pipeline, El Paso Pipeline, and the Mojave Pipeline. The ownership of these pipelines is complex. For example, the Transwestern Pipeline Company, based in Houston, Texas is wholly owned and operated by Cross Country Energy, LLC which is owned by CCE Holdings, which is a joint venture of Southern Union Company and GE Commercial Finance's Energy Financial Services.

Most of the imported natural gas is delivered to the PG&E and SoCalGas intrastate transmission pipeline system, commonly referred to as the "backbone pipeline system". PG&E and SoCalGas are not allowed to own natural gas production facilities – they are required by law to purchase natural gas from producers and marketers. From here, it is either delivered directly to large non-core customers, into the local transmission and distribution pipeline systems, or to storage fields. Some of the imported natural gas goes directly to large consumers, bypassing the backbone system.

As demand for natural gas continues to increase, California can expect to begin importing LNG to supplement the traditional out-of-state supplies. The LNG will be imported by tanker ship, re-gasified, and stored at the port. The re-gasified LNG would be transferred to the utility transmission pipeline system as needed.

Users of a natural gas industry GHG reporting protocol include the following types of entities:

Activity	Reporting Entity
Gas/crude oil exploration and production operations	Major oil companies, independent oil and gas producers, contracting drilling and production companies.
Pipeline transport from wells to processing.	Major oil companies, independent oil and gas producers and independent natural gas processors.
Natural Gas Processing	
Interstate gas transport	Interstate pipeline owners.
LNG transport, re-gasification storage, transfer	LNG importers, ports.
Intrastate transport and distribution	PG&E, SoCalGas, local utilities
Natural gas storage	Producers, utilities

2.2 California Oil Industry

Like the natural gas industry, all steps in the oil production process from exploration to retail sales are present in California. California produces approximately 40 percent of the crude oil refined in the state. There are over 45,000 producing oil wells located in San Joaquin Valley, Los Angeles, Long Beach, Orange County and along the central coast. Offshore wells are located off of Santa Barbara, Ventura, San Luis Obispo and Huntington Beach. The offshore production in California waters (within 3 miles of the shore) represents approximately 6 percent of California's total crude production[8].

Approximately 60 percent of the crude oil refined in the state is imported by marine tanker to major ports in Northern and Southern California. An extensive pipeline system transports crude oil from production areas and the ports to refineries. The major crude oil pipelines are: All American, Chevron, Four Corners, Mobil, Shell, Texaco, Unocal, and ARCO[9]. In 2004, there were 24 major refineries in California with total distillation capacity of nearly 725 million barrels per year. These refineries operate at nearly maximum capacity to produce sufficient refined product for California.

At present, only small amounts of refined product are imported into California, but this is projected to increase as demand continues to rise and there are no plans to expand in-state refining capacity. Refined product is imported through pipelines owned by Calnev, Shell and Kinder Morgan. Refined product is transported from the California refineries to distribution terminals and marine tankers via pipelines and from the distribution terminals to ~10,000 California retail stations via tanker trucks.

California oil industry activities affected by an oil & gas GHG reporting protocol include:

Activity	Reporting Entity
California based crude oil exploration, extraction and production	Major oil companies, independent oil and gas producers, contract drilling and production companies
Crude oil pipeline transport from wells and ports to refineries	Crude pipeline owners/operators
Marine tanker crude transport	Major oil companies, shipping companies
Crude handling operations at ports	Ports
Refinery operations	Major oil companies, independent refiners
Refined product transportation (marine, pipeline, tanker truck)	Major oil companies, independent refiners, pipeline, trucking, and shipping companies.
Retail station fueling operations	Major oil companies, independent retailers

[8] EIA Petroleum Supply Annual 2003 Volume 1, "Production of Crude Oil by PAD District and State".

[9] www.tonto.eia.doe.gov/oog/info/state/ca.html

3. Comparison of CCAR and IPIECA

This Phase I report compares the IPIECA guidance and the CCAR reporting and certification protocols for the oil and gas industries. The CCAR General Reporting and Certification Protocols as well as the accompanying Guidance document[10] were reviewed and compared to the IPIECA Guidelines for reporting greenhouse gas emissions. The intent was to assist the Energy Commission staff in evaluation of the protocols to determine entity emission reporting boundaries, and guidance for the construction, maintenance, and verification of emission inventories of entities within California's oil and gas sector.

The IPIECA Guidelines document is largely based on the WRI general reporting protocol (many sections are taken directly from the WRI protocol) and the level of detail is consistent with the WRI protocol with phrasing tailored to the oil and gas industry.

The following sections describe the CCAR and IPIECA guidance on key reporting and certification issues and highlight any inconsistencies between them.

3.1 GHG Emission Report Contents

Both the CCAR reporting protocol and the IPIECA Guidelines provide a list of required and optional reporting elements; these are summarized in Table 1. The term "required" is not entirely accurate for the IPIECA document since it is not a reporting protocol but rather a set of guidelines for entities that could report to one or more of a variety of reporting programs. For the purposes of Table 1, the term "required" is utilized where the Guidelines say entities "should" report these elements.

3.2 Reporting Boundaries

Before the GHG emission estimation and reporting process can begin, the reporting entity must determine what the organizational, operational, and geographic boundaries are. These boundary concepts are discussed in both documents and generally have the same meanings thought the recommended reporting approaches are slightly different. The following subsections explain each type of boundary and compare the IPIECA and CCAR protocols for each of these boundaries.

[10] CEC Report "Guidance to the California Climate Action Registry General Reporting Protocol", June 2002.

Table 1. Comparison of Required Reporting Elements

Reporting Element	IPIECA Guidelines	CCAR Reporting Protocol
Kyoto Protocol GHGs (CO_2, CH_4, N_2O, HFC, PFC, SF_6)	"Required" individually and on a total CO_2- equivalent basis. Other GHGs optional.	CO_2 only for first 3 years. For 4th & subsequent years, all required individually and on a CO_2-equiv basis. Other GHGs optional.
Direct emissions from stationary and mobile combustion, process and fugitives.	"Requires" reporting of material direct emissions.	Requires reporting of significant direct emissions.
Indirect emissions from purchased electricity, heat, steam cooling.	Optional	Required
Other Indirect emissions	Optional	Optional
Boundaries (Organizational, operational, geographic)	"Required" (not geographic)	Required
Baseline	Optional	First year reporting all 6 GHGs is defacto baseline – other years may be selected.
Normalized Emissions	"Required"	Optional
Description of quantification method	"Required"	Must provide to certifier.
Qualifications to data	"Required"	Silent
Context for changes	"Required"	In baseline maintenance.
Emissions associated with exported energy (separately)	"Required"	Required only as part of direct emissions.
Emission reductions due to projects	"Required"	Silent
Reductions banked, sold, purchased.	"Required"	Not applicable.
Emissions from biologically sequestered carbon (e.g. biomass comb)	"Required"	Silent
Emissions from geologically sequestered carbon	"Required"	Silent
GHG management or reduction programs	"Required"	Optional
Verification/certification of results	Verification optional	Required
Discussion of inventory quality	Optional	By certifier.

3.2.1 Organizational Boundaries

A reporting entity is an entity in its entirety, such as a corporation or other legally constituted body. Operations that are within a reporting entity's organizational boundary are essentially the operations/emissions that the entity claims responsibility for. Both the IPIECA Guidelines and the CCAR Protocol describe two different organizational reporting approaches: equity share and operational control[11]. Briefly, the equity share approach requires a reporting entity to report GHG emissions from all sources that it has equity in by applying its percent ownership of each source to the sources' annual emissions. The operational control approach requires a reporting entity to report 100 percent of the GHG emissions from sources it has operational control over, regardless of equity position. If a reporting entity has equity in but does not have operational control over a source, it does not report the source's emissions.

For joint ventures, it may be difficult to determine which entity has operational control. One can envision many different criteria for determining which entity in a joint venture has operational control. Table 2 shows the IPIECA and CCAR criteria for determining operational control of a joint venture – the criteria are essentially the same.

Table 2. Operational Control Criteria for Joint Ventures

IPIECA Operational Control Criterion	CCAR Management Control Criteria
The company has authority to introduce and implement its operational and environmental, health, and safety (EHS) policies.	Reporting entity has management control if it has control over operational, health, safety, and environmental policies.
Except in rare circumstances, company holding the operating license has operational control.	Control > 50% of voting interest whether by equity, agreement/contract.

Whichever method is chosen, both IPIECA and CCAR state that this method must consistently be used for all GHG sources and ideally year to year. The IPIECA document does not advocate either organizational boundary approach. Rather, it encourages entities to disaggregate their emissions quantification down to the emission source level, and then roll the emissions up in both the equity share and operational control accounting methods. In this way, entities have sufficient accounting flexibility to participate in any program (whether chosen or mandated). For these same reasons, the current CCAR Protocol encourages using both the management control and equity share approaches although the reporting tool, CARROT, assumes the management control approach.

[11] The CCAR General Reporting Protocol uses the term "Management Control" for "Operational Control". In this report, the two terms are used interchangeably.

Although California has large complex multi-national corporations in the oil and gas industry, its parts still may be broken down into the commonly encountered business arrangements that the CCAR and IPIECA/WRI general reporting protocols address. Complexity arises because a reporting entity may have many joint ventures and subsidiaries under it that in turn also have formed joint ventures and own subsidiaries. The IPIECA document describes petroleum industry organizational relationships in their Table 3-1 and a description of how emissions would be reported on an equity share basis. Table 3 below draws on this table and adds a column for organizational control reporting.

The only atypical relationship is the Production Sharing Agreement (PSA) which is commonly used in exploration and production activities. The IPIECA document focuses on PSA arrangements with foreign countries; however this type of arrangement happens within California as well, with a landowner assigning drilling rights in exchange for royalties on any resulting production.

In terms of organizational boundaries, the IPIECA Guidelines and the CCAR protocol are largely in agreement. One exception is the case where the reporting entity owns between 1 and 20 percent of a publicly traded company. The IPIECA Guideline advises that the reporting entity need not report any of these emissions, regardless of whether it reports on a management control or equity share basis. Alternatively, the CCAR protocol requires a reporting entity that utilizes the equity share approach to report its equity share of the company's emissions when the equity share is between 1 and 20 percent. If the reporting entity utilizes the management control approach, then under the CCAR protocol the entity would not report any emissions. There are large petroleum companies that likely own between 1 and 20 percent of another sizable entity which may or may not quantify and provide its emissions data to the reporting entity. This requirement may preclude the use of equity share reporting for large oil companies.

One subtlety that is not addressed by the IPIECA document but is mentioned in the CCAR protocol is the case when a reporting entity has joint control and ownership with another entity of an emission source. The CCAR protocol states that when both management control and equity are equally divided between two or more owners, emission reporting should be done on an equity share basis for this source. In this case the CCAR allows the equity share and management control accounting methods to be mixed.

Table 3. Common Petroleum Industry Investment Structures (based on IPIECA Guidelines Table 3-1)

Type of Investment	Description of Organizational Relationship	Operational Control Reporting	Equity Share Reporting
Subsidiary	The reporting entity either wholly owns the subsidiary, or enough of its voting stock that it has full control of the subsidiary.	Reporting entity has management control and therefore reports 100% of subsidiary's emissions.	Reporting entity reports its equity share of the emissions.
Joint venture among two or more companies that operates as a separate company.	Several corporations have formed a company by combining some of their existing assets and/or capital. The several corporations are the sole shareholders.	• If an entity has >50% ownership, it has financial control implying management control. This entity reports 100% of the GHG emissions. • If an entity owns < 50%, but has management control (by agreement, majority of votes, etc.), this entity reports 100% of the GHG emissions. • *If ownership and operation is evenly divided among entities, GHG emissions are reported on equity share basis.*	The reporting entity reports its equity share of the emissions.
Joint venture among several companies to develop a production facility.	Corporations work in partnership without forming a new company. One serves as operator.	If the reporting entity is the operating partner, it would report 100% of the emissions. If not, it would not report these emissions.	The reporting entity reports its equity share of the emissions – typically according to the working interest.
Joint venture between a landowner and one or more companies to produce oil/gas in a production sharing agreement (PSA)	Landowner assigns drilling rights to others in exchange for royalty payments on any resulting production.	Typically the landowner little operational control and would report no emissions. The entity with management control would report all GHG emissions. In the event ownership and management is evenly divided, reporting would be on an equity share basis.	The reporting entity would report emissions based on the share of production (net production if owner is paid in-kind with oil).
Stock ownership in a publicly traded corporation – significant share of ownership.	A separate public company in which the reporting entity has ≥ 20% ownership.	The reporting entity is not required to report these emissions, but may coordinate with other entities to report on a pro-rata basis (coordinate to ensure no underreporting or double counting of emissions).	The reporting entity reports its equity share of the emissions.
Stock ownership in a publicly traded corporation – small share of ownership	A separate public company in which the reporting entity has < 20% ownership.	Reporting entity would not report any of these emissions.	• The IPIECA Guidelines say reporting entity does not report any GHG emissions. • The CCAR protocol says emissions must be reported for equity from 1% to 99%.

3.2.2 Operational Boundaries

The term operational boundary is used by both the IPIECA Guidelines and the CCAR Protocol. This essentially means determining the emission sources that must be reported. GHG emissions are divided into two types: direct emissions and indirect emissions. Direct emissions come from sources that are owned or controlled by the reporting entity. Indirect emissions are emissions that occur because of the reporting entity's actions but are not produced by the reporting entity.

Table 4 provides a comparative list of direct emissions that are explicitly called out in the CCAR protocol and the IPIECA Guidelines. As might be expected, the IPIECA protocol includes specific oil and gas industry emission sources. The CCAR General Protocol should probably add flares and fired equipment to its list. Inclusion of incinerators by IPIECA is likely covered in CCAR's stationary combustion for the production of heat, steam or electricity. In developing an oil and gas protocol, CCAR may want to provide a more comprehensive list of direct emission sources.

Table 4. Comparison of Required Direct Emission Sources

CCAR Protocol	IPIECA Guidelines
Stationary combustion for the production of heat, steam or electricity.	Stationary combustion for production of heat, steam, or electricity.
	Combustion in flares and incinerators.
	Production of work by engines and turbines (e.g. to drive pumps/compressors)
Process emissions (such as from cement, adipic acid, ammonia, agricultural, etc.)	Process emissions (gas processing, oil refining, petrochemical manufacture)
Mobile combustion (i.e., cars, trucks, rail, air, and other transport) owned or controlled by entity and used for moving raw materials, finished products, supplies, people.	Transportation in company-owned or controlled motor vehicles and vessels, such as tank trucks and oil tankers.
Fugitive emissions (pipeline leaks, HFCs from air conditioners, etc)	Fugitive losses from equipment leaks such as gas pipeline systems.

While the CCAR protocol requires reporting of indirect emissions from purchased energy (electricity, steam, heating and cooling), the IPIECA guidelines treat indirect emissions as optional reporting elements. Table 5 provides a comparison of explicit examples of indirect emission reporting requirements. The IPIECA guidelines have more oil and gas industry specific examples of indirect emissions; these are optional (though encouraged) reporting items in the IPIECA guidelines.

Table 5. Comparison of CCAR and IPIECA Indirect Emissions Sources

	CCAR Protocol	IPIECA Guidelines
Purchased electricity	Required	Encouraged
Purchased steam/heating/cooling	Required	Encouraged
Production & transport of purchased raw materials	Optional	Minor: only report if have specific need.
Outsourced activities, contracting	Optional	Optional
Manufacture and transport of imported hydrogen for refining operations	Subset of raw material transport (optional)	Encouraged
Third party shipping of crude and products in vessels, truck, rail, pipeline up to point of sale	Subset of outsourced activities (optional)	Encouraged
Contracted exploration and production (well drilling, maintenance and workovers)	Silent	Encouraged
Toll manufacture of chemicals by third party.	Subset of outsourced activities (optional)	Encouraged
Off-site waste disposal including transport	Optional	Minor: only report if have specific need.
Employee commuting, business travel	Optional	Minor: only report if have specific need.
Product use	Optional	Should be reported by end-user, especially for oil & gas industry
Product disposal	Optional	Silent

The treatment of emissions associated with losses along electric transmission and distribution lines, generally assumed to be 7 percent, is consistent between the IPIECA Guidelines and the current version of the CCAR protocol. These emissions are assigned to the owners of the transmission and distribution lines. Earlier versions of the CCAR protocol had assigned the line losses to the end user.

Emissions from leased facilities/sources are a reporting issue on which the IPIECA guidelines and the CCAR protocol differ. Possible leased equipment direct and indirect emissions include:

- Industrial operations in a leased building
- Fuel consumed by leased vehicles
- Leased equipment
- Electricity metered and paid for by the reporting entity in a leased office building

CCAR requires that these emissions be quantified and reported as if they were wholly-owned by the reporting entity. Therefore, regardless of whether the entity is utilizing the equity share or operational control approach, 100 percent of these emissions must be reported. The IPIECA Guidelines state that if the reporting entity utilizes the operational control accounting approach, 100 percent of the emissions from leased sources must be reported. However, if the reporting entity utilizes the equity share approach, it would only report emissions for leased sources if the lease is a finance or capital lease. No leased source emissions would be reported under the equity share approach if the lease is an operational lease. The IPIECA Guidelines state:

> *A finance or capital lease is one that transfers substantially all the risks and rewards of ownership to the party leasing property from its owner. Such leases are treated as assets in financial accounting and are recorded as such on the balance sheet. The party leasing an emissions source under a financial or capital lease should therefore account for GHG emissions as if it owned the source…*
>
> *… [in an operational lease] no liabilities or assets are recorded in financial accounting. The party leasing the emissions source should not report GHG emissions produced by operational leases.*

The IPIECA Guidelines go on to state that most leases will be capital leases, however rented office space is an operational lease and emissions from this category would not be reported under the equity share approach.

3.2.3 Geographic Boundaries

The IPIECA Guidelines do not discuss geographic boundaries since it is not a protocol for a specific reporting/trading scheme. The CCAR protocol requires all emissions in California to be reported and encourages reporting of emissions from all activities in the United States. It is also possible to report emissions from activities outside of the United States in the optional reporting area of CARROT. For California-only reporting, CCAR provides the following guidance:

- Indirect emissions from electricity consumption in California are reported regardless of the fact that the direct emissions from electricity production may occur outside of California.

- Direct GHG emissions from all mobile sources based (licensed/registered) in California should be reported.

- Direct emissions associated with refueling for mobile sources based outside of California for fuel used in California.

3.3 Reporting Principles

Both the IPIECA and CCAR documents have several overarching principles in common that are intended to guide preparation of GHG emission inventories and reporting. These are completeness, consistency, accuracy and transparency. Each of these principles is discussed in the following sections, with differences between the two documents highlighted.

3.3.1 Completeness

One of the principles fundamental to any emission reporting program is the concept of completeness. Ideally, the reporting entity would make an effort to quantify and report emissions from all sources within its chosen boundary. In practice however, GHG accounting can be an expensive, ongoing undertaking. It can be argued, especially for large reporting entities, that it does not make sense to account for each individual emission source if it will make a negligible contribution to total emissions.

Recognizing this, both the CCAR protocols and the IPIECA Guidelines provide for omitting non-material or insignificant emissions though different approaches are utilized. The CCAR protocol requires reporting entities to report at least 95 percent of their GHG emissions. The entity must estimate emissions from all sources and if one or more sources sum up to less than 5 percent of total emissions, the entity is not required to report these “de minimis” or “non-significant” emissions. This approach allows reporting entities to use less detailed and presumably less time consuming and/or costly methods to conservatively estimate emissions from their smallest sources. However, for the first reporting period in which a source is defined as de minimis, emissions must be quantified sufficiently to allow the certifier to agree that emissions are de minimis.

Although the IPIECA/WRI approach rejects the de minimis concept, their guidelines acknowledge that reporting entities will make decisions to not report certain smaller sources due to the resources required to quantify their emissions. These smaller sources are assumed to contribute insignificantly (non-materially) to the total emissions reported by the reporting entity. These omissions are considered to be non-material. If no materiality threshold is set by the program in which the reporting entity participates, it is up to the independent verifier to determine whether the omissions are material or not.

One could therefore conclude that both the CCAR and IPIECA documents allow de minimis emissions to go unreported but the CCAR quantifies the allowable omission while IPIECA allows the individual verifiers determine the limit on a case by case basis.

3.3.2 Consistency: Establishing and Maintaining a Baseline

Both the IPIECA Guidelines and the CCAR protocol discuss the concept of establishing and maintaining a GHG emission baseline. The IPIECA Guidelines document

encourages reporting entities to establish a baseline so that emission reduction progress can be tracked over time. The IPIECA Guidelines do not make a specific recommendation as to which year to select as a baseline year – it simply states that the emissions data must be verifiable, allow for consistent estimation and accounting across the company, and be consistent with the requirements of the program to which the entity is reporting.

The CCAR protocol states "at this time, participants are not *required*, but are *encouraged* to establish a baseline reporting year". If a participant chooses to select a baseline year, the first year of reporting all 6 GHGs (fourth reporting year) is the default baseline year, but any other year with certified data may be selected as the baseline year.

Once an entity has selected a baseline year against which to compare emission increases or decreases, the baseline needs to be "maintained" to ensure that for each subsequent year it is a fair comparison to reported emissions. Both the IPIECA and CCAR documents provide guidance on when the baseline needs to be adjusted. Specific direction on baseline emission adjustments are provided in Table 5. In general, the two documents agree that the baseline should not be adjusted for "organic growth or decline" which is defined by the CCAR protocol as follows:

> *Organic growth or decline refers to the increase or decrease in production output, changes in product mix, plant closures, and the opening of new plants that are not the result of changes in the structure of the participant's organization or the result of shifting operations into or out of California or the United States.*

From Table 6 it may be seen that both documents agree on baseline adjustments. The IPIECA protocol discusses outsourcing and in sourcing at length, stating that if a company tracks both direct and indirect emissions, outsourcing/insourcing will not change the total baseline emissions. The CCAR protocol says that in practice, there will be a direct baseline, an indirect baseline, and a total baseline. Outsourcing and insourcing will affect the direct and indirect baselines, but the total will not be adjusted.

The CCAR protocol advises that a participant need not adjust the baseline if it has changed by 10 percent or less. This is a cumulative change e.g., if it changes by 4 percent each year for three years, the baseline would need to be adjusted the third year since the cumulative change will be 12 percent. The certifier must verify the change in baseline emissions each year. The IPIECA document makes no recommendation on how often the baseline needs to be updated, only that it needs to be updated when there has been a "significant" change.

Table 6. Direction on Baseline Adjustment

	CCAR Protocol	IPIECA Guidelines
Mergers, acquisitions, divestitures	Adjust	Adjust if came into existence before reporting entity set baseline year.
Outsourcing activities	Adjust if previously conducted internally.	Adjust if operations came into existence before the base year was set.
Insourcing activities	Adjust if previously contracted to outside parties.	Adjust if operations came into existence before the base year was set.
Shifting emissions into or out of geographic boundaries	Adjust	Silent
Improved GHG accounting methodologies	Adjust	Adjust
Discovery of errors	Silent	Adjust if significant.
Organic growth or decline	Do not adjust	Do not adjust

3.3.3 Accuracy

The CCAR protocols require that emission reports be free of material misstatements, achieving a level of at least 95 percent accuracy. CCAR distinguishes between inherent uncertainty and reporting uncertainty. Inherent uncertainty is the uncertainty in emission factors and monitoring/recording activity data. Reporting uncertainty is due to misidentification of emissions sources (leaving some out), data handling errors and emission miscalculations. CCAR requires that the reporting uncertainty be maintained at 5 percent or less.

During the certification process, the certifier may find a discrepancy between the reported emissions and those estimated by the certifier. According to the CCAR protocol, if the total emissions estimated by the certifier are more than 5 percent higher or lower than the total emissions estimated by the reporting entity then the discrepancy is defined as a *material discrepancy*, and the emission report is not certifiable until the certifier and reporting entity can resolve the difference.

The IPIECA Guidelines advises that GHG estimates “should be systematically neither over nor under the true emissions value, as far as can be judged, while recognizing the need to balance the cost-effectiveness of obtaining accurate emissions estimates with the intended use for the emissions information”. The IPIECA Guidelines later define *material discrepancy* as an error (either an oversight, omission, or miscalculation) that results in the reported quantity being sufficiently different from the true value that it influences decisions or actions. While the IPIECA Guidelines document does not

specify a materiality threshold, it does acknowledge that a threshold, predefined by a reporting program, is a useful guide to verifiers.

One may conclude that the CCAR and IPIECA Guidelines are consistent on the concept of accuracy.

3.3.4 Transparency

The IPIECA Guidelines document defines transparency as “the degree to which information on the processes, procedures, assumptions, and limitations of the GHG inventory are disclosed”. A high degree of transparency is endorsed. The IPIECA Guidelines document states that an independent external verification is a good way to increase transparency and ensure that an audit trail has been established.

The CCAR ensures transparency by requiring participants and to report their emissions with the on-line reporting tool (CARROT) and to have their emissions certified by an independent third party.

3.4 Certification and Verification

The terms “certification” (used in the CCAR protocol) and “verification” (used in the WRI and IPIECA documents) are used interchangeably in this report and mean the process of having an independent third party perform an audit of a reporting entity’s GHG emission inventory. The section on verification in the IPIECA Guidelines is a condensed version of the verification section in the WRI GHG protocol. The WRI/IPIECA Guidelines encourage verification, and essentially refer the reporting entity to the verification requirements of the specific program to which it reports.

4. Conclusions and Recommendations

The foregoing discussion shows that on most issues the CCAR General Reporting and Certification Protocols are consistent with the guidance provided in the IPIECA Document. However, there are several areas of disagreement on organizational and operational boundaries which are summarized below. In most cases, the differences are rooted in fundamental approach and CCAR may or may not wish to realign the principles of its protocols with the suggested guidelines of IPIECA.

Organizational Boundary Differences

- When the reporting entity owns 1-20% of a publicly traded company, the IPIECA guidelines say the emissions of the publicly traded company need not be reported regardless of whether the entity reports on an equity share or operational control basis. The CCAR protocol requires that these emissions be reported if the entity utilizes the equity share approach. This requirement should be viewed within the context of a multinational company that has a myriad of operations and business interests comprising the vast majority of their GHG emissions. Inclusion of multiple tiny fractions of reported equity would likely inject more error than accuracy into the calculated emissions.

- When operational control and equity of a GHG emission source are both equally shared, the CCAR protocol specifies that the emissions may be reported on an equity share basis even if the overall reporting approach is operational control. The IPIECA document does not offer guidance for this special situation.

Operational Boundary Differences

- Both documents agree on direct emission reporting although the IPIECA guidelines have more oil and gas specific sources than the CCAR general reporting protocol. The companion report to this document (Review of API compendium) has guidance on specific sources to include in an oil and gas specific protocol.

- Both documents allow for non-reporting of immaterial or de minimis emissions. In the case of CCAR, a 5% threshold is stipulated, while the IPIECA guidelines leave this up to the verifier to determine. Both systems require some technique for making rough but conservative estimates of the emissions that may eventually be determined to be immaterial. The industry needs to devise common methods to facilitate these high level estimates in order to reduce the reporting burden and enable documentation of uncertainty in the overall entity emissions estimate. This common method will assist the verifiers in their efforts to address material discrepancy.

- Indirect Emissions Reporting Differences:

    1. CCAR requires reporting of indirect emissions associated with purchased energy (electricity or steam). This is an optional element in the IPIECA Guidelines.

    2. In general both documents state that emissions from outsourcing are optional. However, the IPIECA document strongly encourages reporting emissions from contracted exploration and production, toll manufacture, and third party shipping.

    3. CCAR requires that 100% of emissions from leased facilities and equipment be reported whether the entity is reporting on an operational control or equity share basis. IPIECA document requires these emissions to be reported if the operational control approach is utilized. Under the equity share approach the emissions would only be reported if the lease is a capital lease. Most leases are capital leases, but office space is not and therefore emissions attributable to leased office space would not be reported if the equity share approach is utilized.

Geographic Boundary Issues

An oil and gas industry specific protocol needs an explicit definition of geographic boundary for entities with offshore emission sources that choose to report "California only" emissions. A simplistic option would be to require reporting only those emissions that occur in California waters (within 3 miles of the coast). However, it may be appropriate to include all off-shore oil and gas exploration and production activities off of California's coast regardless of where they lie with respect to the 3 mile boundary. The Coastal Zone Management Act (CZMA), enacted by Congress in 1972, gave the California Coastal Commission (CCC) authority to review and act on federally permitted projects to ensure their consistency with California's Coastal Management Plan. The CZMA specifically allows the CCC authority to review projects including offshore oil and gas production and exploration activities in federal waters (outside the 3 mile boundary) for impacts on coastal resources. Since GHG emissions in federal waters impact coastal resources, it may be appropriate for a state agency to require that these emissions be included in a California GHG emission inventory.

Separate Protocol for Natural Gas Transmission, Storage and Distribution

It has been suggested that CCAR develop a separate protocol for natural gas transmission, storage and distribution activities rather than including it as a subsection in a large oil and gas industry protocol. This may be a sensible approach since most entities utilizing this protocol would not be affected by the other parts of a general oil and gas industry protocol. If CCAR decided to do a separate protocol, the upstream boundary could be drawn consistent with the definitions in the MACT standards for oil and natural gas production facilities. "Upstream" source applicability for the oil and natural gas standard is:

> *§ 63.760 (a)(3) Facilities that process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user. For the purposes of this subpart, natural gas enters the natural gas transmission and storage source category after the natural gas processing plant, when present. If no natural gas processing plant is present, natural gas enters the natural gas transmission and storage source category after the point of custody transfer.*

Where custody transfer from processing to transmission/storage is defined in 40CFR § 63.761 as:

> *the transfer of hydrocarbon liquids or natural gas: after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation…*

There is also a MACT standard for natural gas transmission and storage operations. Applicability is defined in 40CFR § 63.1270(a) as:

> *… natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company)…*

where transportation and storage facility is defined in § 63.1271 as:

> *any grouping of equipment where natural gas is processed, compressed, or stored prior to entering a pipeline to a local distribution company or (if there is no local distribution company) to a final end user. Examples of a facility for this source category are: an underground natural gas storage operation; or a natural gas compressor station that receives natural gas via pipeline, from an underground natural gas storage operation, or from a natural gas processing plant. The emission points associated with these phases include, but are not limited to, process vents. Processes that may have vents include, but are not limited to, dehydration and compressor station engines.*

Part 2

Review of the API Compendium for Oil and Gas Operations in California

Prepared by ICF Consulting

5. Introduction

Estimating greenhouse gas (GHG) emissions from petroleum and natural gas operations can vary in effort depending on the desired accuracy, geographical scale, level of detail, and adherence to good practices. A GHG inventory undertaking can range from direct measurement of emissions from a single process unit to estimation of national emissions from published studies and key industry data. The American Petroleum Institute (API) *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* (Compendium), last published in February 2004, is a guide to estimating emissions from oil and gas industry facilities. The Compendium lists multiple approaches to estimate GHG emissions based on currently available public documents and studies. The Compendium is a bold and important step in establishing a uniform basis on which all countries and companies worldwide can estimate their GHG emissions. The 2006 IPCC Guidelines "for country reporting" reference the IPIECA Guidelines, which references the API Compendium. Hence, the API Compendium is becoming a worldwide standard for "country" reporting.

The purpose of this report is to evaluate the Compendium methods for use in performing GHG emissions inventories by petroleum and natural gas industry COMPANIES (entities) in California. Where better methods are known to exist, this review identifies those along with reference to public documentation. The boundaries that govern the evaluation and recommendations from this review are the operating facility boundaries of all types of oil and gas companies in (and potentially outside) the State of California, including crude oil, condensate and natural gas exploration and production, oil and condensate transportation, gas gathering and boosting, gas processing, gas transmission, storage and distribution, liquefied natural gas (LNG) production, storage, import, export and injection into distribution systems, petroleum refining, and refined products and byproducts transportation and distribution to consumers. The boundaries do not include use of those natural gas and petroleum fuels, although fuel composition data in the Compendium serves equally well in estimating CO_2 emissions from burning those fuels. Subsequent to development of the draft reports for this study, the Interstate Natural Gas Association of America (INGAA) published *Greenhouse Gas Emission Estimation Guidelines for Natural Gas Transmission and Storage*, September 28, 2005. This document was not available for this review of the Compendium, and can be expected to address many of the deficiencies in the Compendium related to its application to natural gas transmission. Neither document apparently addresses natural gas distribution emissions adequately.

In this review, it is important to distinguish between company (entity) GHG emissions inventories and country or state inventories. Companies can exactly know their facilities, technologies and operating practices. Governments through their agents generally do not know all details of all private sector facilities, technologies and operating practices. Herein lays one of the fundamental points of this review: while most of the CO_2 and N_2O emissions methods are based on individual fuels and combustion technologies, most of the methane emissions in the Compendium are based on a U.S. national survey performed by the Gas Research Institute (GRI) and U.S. Environmental Protection

Agency (EPA) in the early 1990's. The stated intent of the GRI/EPA survey published in 1996 was to characterize the methane emissions from the U.S. natural gas industry, and it met this intent exceptionally well. The intent was not stated to be a basis for estimating methane emissions from any particular company. Therefore, the survey statistically averaged emissions measurements or estimates across broad ranges technologies and operating practices for a discreet number of emissions sources as they existed in the late 1980s and early 1990s. This produced national average emissions factors and factors estimating the number of sources (called "activity" factors) which, when multiplied together gave a statistically meaningful estimate of national methane emissions.

In a number of ways, California's oil and gas industries are quite different from the national average, and more importantly, both California and the U.S. oil and gas facilities today are quite different from the early 1990's when the national methane emissions survey data was collected. Unique aspects of California's operations reduce the accuracy of some methane emissions estimating methods and render other methods less suitable for a company GHG inventory. The Compendium provides for some of these differences (e.g. glycol dehydrator configuration), but in general not the differences in technologies for several sources (e.g. compressors, pneumatic devices). However, the Compendium is intended to be "evergreen" and this review provides an opportunity for additions to the next edition of the Compendium. While GHG emissions estimation and reporting are evolving, it makes good sense to make the best use of what data is available, and combining that data into nation-wide averages is certainly not the only approach and perhaps not the best approach for company reporting.

The fundamental difference in the Compendium approach to CO_2 and N_2O emissions estimation methods render them accurate and enduring over time. Because the large majority of GHG emissions in the oil and gas industries is CO_2, this aspect of the Compendium is entirely suitable on a country or company basis, worldwide. However, CO_2 emissions from burning a mass of a particular fuel can not be reduced by any technology or operating practice. Surrogate N_2O emissions can be reduced by technology. More importantly, methane emissions are a function of technology, operating, and maintenance practices. Methane emissions can be reduced to near zero (not always cost effectively), and the saved methane has an economic value.

For these reasons, this review does focus on methane, and relatively small emissions sources that are cost effective to reduce, and thereby should be represented in a compendium of emission quantification methods. This in no way diminishes the importance and value of the Compendium's methodologies for CO_2 and N_2O emissions estimation, or the value of having multiple choices in methods for methane emissions estimates, so long as those choices are clearly defined.

Section 6 of this report provides an evaluation of the Compendium's conventions for conducting an inventory. Section 7 discusses ICF's findings: how well each of the Compendium's inventory methods applies to entity (company) reporting in California. Section 8 includes recommendations of improved methods and overall conclusions for this work.

6. *Review of Industry and Inventory Conventions used by the Compendium*

Before delving into the details of the emissions estimation methodologies, the API Compendium provides an overview of the oil and gas industries, defines the industry sectors, and provides an overview of emissions categories. This section of the report provides a review of these conventions that are important for a GHG inventory apart from the actual emissions estimation methodologies and emissions factors.

Two GHG inventory approaches may have different conventions for naming emissions sources, selecting industry sectors, and using good practices. In its sections 1.0 through 3.0, the Compendium discusses how it conceptualizes the industry for a GHG inventory.

6.1 Emissions Categories

GHG Emissions in the oil and gas industry can be classified in three different categories or 'source classes' as API Compendium labels them. The three mutually exclusive categories that the compendium defines are:

Combustion Emissions: These are emissions resulting from burning of carbon-containing fuels in stationary or mobile equipment such as engines, burners, heaters, boilers, flares and transportation vessels.

Vented Emissions: These are defined as those occurring from normal operations. This definition can be made clearer by stating that these emissions are intentional or designed into the process or technology to occur during normal operations. They can not be "fixed" to eliminate "leaks."

Fugitive Emissions: Fugitive emissions are unintentional releases from equipment leaks at sealed surfaces, as well as from underground pipeline leaks. This definition can be improved by noting that fugitive emissions can be individually found and "fixed" to make the emissions "near zero."

Because these terms may have slightly different meanings depending on the study, an inventory should define its categories and use them consistently. The Compendium's definitions for these sources are probably the most widely accepted and are suitable for California.

Another strength of the Compendium is that it also groups the three emissions sources into sub-categories. This provides a greater potential for analysis to understand which categories are most significant or which categories are most accurate in an inventory.

6.2 Industry Sector Definitions

Operating practices, such as temperatures and pressures, vary significantly as a product exits a well, flows though midstream facilities, and ultimately travels to market. Different operating conditions through this infrastructure affect GHG emissions. Tight classifications of industry sectors help to match appropriate operating practices and conditions to an emissions source.

The Compendium's sector definitions aggregate several steps of the gas industry which have different operating characteristics and may be more accurately evaluated as individual sectors. More specific sectors give an inventory the flexibility to customize emissions estimates to the operating practices. Even if two sectors share the same emissions estimation method, keeping them separate allows for flexibility in the future if new sector-specific data or methods become available. Table 7 lists the Compendium's sector definitions next to recommended optional sub-sectors.

Table 7. Compendium Industry Sectors and Recommended Industry Sector

Compendium Industry Sectors	Optional Sub-Sectors
Exploration, Production, and Gas Processing	Exploration and Production
	Gas Gathering/Boosting
	Gas Processing
Coal Bed Methane Production	Coal Bed Methane Production
Minerals and Mining Operations	Minerals and Mining Operations
Transportation and Distribution	Petroleum Transportation and Distribution
	Gas Transmission
	Gas Distribution
Refining	Refining
Petrochemical Manufacturing	Petrochemical Manufacturing
Marketing	Marketing
Electricity and Heat Generation	Electricity and Heat Generation

Gas Gathering/Boosting involves transporting gas from well sites, and this sub-sector differs from Gas Transmission and Gas Distribution because of the pressure and quality of the gas, as well as impurity removal steps exclusive to Gathering/Boosting lines.

Gas Processing differs from both Exploration and Production and Gas Gathering/Boosting since processing facilities are more likely to be electrified than

production sites or gathering lines and may be subject to different leak detection and repair regulations.

Gas Transmission operates at much higher pressures than Gas Distribution.

6.3 Naming Emissions Sources

Industry terminology can vary from source to source, and the Compendium provides brief descriptions of the sources. However, some sources introduced in the Compendium's section 2.0 are called by a different name in later sections. Instances of this are identified in Appendix A to assist API and California to avoid confusion and prevent this from propagating to a state-wide reporting guideline.

6.4 Default Parameters

Parameters used to estimate emissions vary to some extent in the field, depending on company operating practices and/or geographic region. For example, natural gas at one well site can be 80% methane, while another well site may be producing gas with 85% methane. For many sources, the estimation methods include some parameters that affect emissions, and the provided default parameter may have been a national or regional average. The Compendium recommends replacing these default parameters and recalculating an estimate with values more specific to the given inventory. A California guideline should follow this recommendation. Beginning with the 1990-2005 U.S. Methane Inventory for Natural Gas Systems (being developed now), the gas production, gathering and boosting emission factors are being expressed by National Energy Modeling System (NEMS) regions, with gas methane content transitioning from the GRI compositions published in 1989 to the GTI compositions published in 1996. Publication of these factors in spring, 2007 will provide a public record of natural gas industry emission factors for the California NEMS region more accurate than the national averages used in the GRI/EPA 1996 study and presently in the Compendium.

7. Evaluation of Compendium Inventory Methods

Section 6 assessed the Compendium view of the petroleum and natural gas industry for the purposes of conducting a GHG inventory. Section 7 evaluates the Compendium emissions estimation methods. In the context of Section 5: California Industry Characteristics, an inventory method can potentially reflect out-of-date operating practices, reflect out-of-region operating practices, or have incorrect assumptions about the emissions source.

This section first explains the methods employed to assess the Compendium for California. The second section discusses general findings, and the final section discusses findings specific to particular emissions sources.

7.1 Compendium Evaluation Methodology

Section 2.2 of the Compendium provides API's comprehensive list of GHG emissions sources, and next to each source is a section reference to find emissions estimation methods. Given the large number of sources and the Compendium propensity to provide multiple methods for each source, this assessment lends itself well to an evaluation matrix, included in Appendix A. The evaluation matrix lists the sources in Compendium section 2.2 in order, shows each inventory method, and provides a written evaluation for each combination of source and method.

Each method has received a different evaluation based on the reviewers' understanding of the California industry, a thorough review of the Compendium inventory methods, seven years' service for the U.S. EPA of careful examination of the 1996 GRI/EPA study and published data that underlies most of the methane default factors in the GRI study and Compendium, extensive knowledge of the Petroleum and Natural Gas Systems while developing the EPA report *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2002*, extensive analysis of the MMS *Gulfwide Offshore Air Data System, 2000,* 27 years of direct petroleum industry experience and nine years experience in the Natural Gas STAR Program researching and writing most of the technical documents posted on the Gas STAR website and conducting 28 technology transfer workshops with the natural gas industry in 12 states. The scope and budget of this project did not allow new analysis, and so these evaluations may be characterized as the reviewers' opinion.

The Compendium presents each source in a separate section which may contain a brief description of the emissions and background data for some of the provided methods. In most instances, the supplied background data is not sufficient to qualify the rigor of default emission factors or estimation methods; the referenced document must be consulted for a full understanding. If the reference document is well-known and understood, comments in the evaluation matrix reflect this knowledge of the reference. If the reference is unavailable, as in the case of the GHGCalc® software

documentation, comments are qualified or conditional based on assumption that the GRI 1996 study underlies those references as well.

In addition to commenting on each source and method presented in the Compendium, this evaluation looked for other areas of review in the Compendium. This includes:

- Instances of missing emissions source
- Instances of missing emissions species
- Sources that were double-counted by an overlap in industry sectors, and
- Sources that could have more specific names for clarification and transparency.

7.2 General Findings

For the most part, the GRI 1996 study is the “bible” of U.S. natural gas industry methane emissions quantification. Therefore, most of the emissions data and emission factors in the Compendium have no equal in published reports. However, the purpose of that study was identification of sources and quantification of U.S. national methane emissions. The purpose was NOT to develop default emission factors for individual companies, or to provide emission factors in a detail suitable for tracking entity progress in reducing emissions by changes in technologies or operating practices.

The Compendium methods and data on evaluating combustion emissions and refinery emissions are considered the best available information.

All recommendations in the Compendium to use direct measurement or process simulation models will evaluate California specific emissions, and thereby will be superior to default emission factors. However, it is generally not practical to gather the data and aggregate similar sources to make these methods time-effective. Because of the large number of sources in the industry, and wide variations in site specific operating conditions or designs, these are rarely the methods of choice for GHG inventories.

The GRI 1996 study underlying many of the Compendium default methane emission factors is growing out of date with changing technologies, improved operating practices, government regulation of emissions, voluntary programs like Natural Gas STAR sharing methane emission reduction techniques, improved methods to find and quantify emissions, and economic conservation driven by the rising price of natural gas. California is in the forefront of U.S. efforts to reduce GHG emissions, and therefore, many of the API Compendium default emission factors need to be updated or modified to best match current oil and gas industry operations in California.

7.3 Source-Specific Findings

The table in Appendix A is a comprehensive review of all methods presented in the Compendium. Rather than repeat every one in text, this section will summarize some of the key areas of deficiency in Compendium methods. Again, this relates to the default emission factors presented, never to direct measurements, process simulations or engineering calculations based on specific design and operating data. The Compendium does note preferred and alternative methods, and use of default emission factors are typically not preferred alternatives. Nevertheless, default factors could and should be provided for company (entity) reporting.

Acid gas removal unit emission factors are presented for amine systems only; more specifically, diethanol amine (DEA) systems. Several new acid gas removal technologies are penetrating the natural gas industry today, some much more cost-effective than DEA units (e.g. membrane separators). All of the new technologies listed in the acid gas section of Appendix A have lower methane emissions than DEA.

Glycol dehydrator default emission factors are derived from the 1996 GRI study, which presented a flawed analysis of process simulator data. This determination is documented in a draft report dated October, 2000, for the U.S. EPA Gas STAR Program and was presented in the September, 2000, Gas STAR Annual Meeting (slides obtainable from EPA). Furthermore, these default emission factors do not include methods to compensate for pressure, the most important factor in methane absorption in the glycol, circulation rate, which is directly proportional to emissions, or stripping gas, which is a direct pass-through to the atmosphere.

Natural gas powered pneumatic instrument controllers and valve actuators are, collectively, the largest source of methane emissions in the 2004 U.S. national methane inventories for natural gas (18%) and petroleum (34%) systems. The Compendium default emission factors are based in the 1992 data collected and reported in the GRI 1996 study, which is growing out of date with the introduction around 1990 of lower emitting low-bleed or intermittent bleed pneumatic devices.

One of the main fugitive and vented emission sources in gas distribution are pipeline leaks. Historically cast-iron pipelines were used for gas distribution. Over the decades, the industry has been replacing these with more modern materials, currently plastic. Even plastic has gone through an evolution when, in 1982, ASTM adopted standard D2837 to correct brittle failures in plastic distribution pipe. The fugitive emissions from these pipes depend in large part on the material as different materials have varying susceptibility to joint leakage, corrosion and cracking. The API Compendium does not provide material specific emission factors as presented in the 1996 GRI study, which is out of date with post-ASTM D2837 plastic pipe emission factors.

Another large source of methane emissions is compressor seals. Again, the Compendium treats these as “fugitive” emissions although seal leakage is designed into the systems. The default factor is based on the GRI study 1992 characterization of the

national average mix of technologies (80% reciprocating compressors, ~20% centrifugal compressors with wet seals, and one centrifugal compressor with a dry seal). Compressor manufacturers report that 90% of new compressors sold into the natural gas industry today are centrifugal with dry seals. California gas transmission, and compressor installations and modernizations are viewed as tracking the national average, and thereby moving away from the GRI basis of compressor emissions.

Gas STAR Partners report replacing wet seals with dry seals, and replacing two and three reciprocal compressors with single centrifugal compressors with dry seals. If TransCanada, with nearly all centrifugal dry seal compressors, used the Compendium factors they would over-estimate their compressor emissions by about 1000%. If Gazprom, with all centrifugal wet seal compressors used the Compendium, they would under estimate their emissions by about 400%. This factor has grown, and continues to grow out of date with the change in compressor seal technology. Furthermore, the emission factors in the GRI study for centrifugal compressor wet seals ignored the seal oil degassing emissions, which are orders of magnitude larger than emissions from the seal itself, and not included under any vented emission category. Recent data on gas processing plants published by Clearstone Engineering in 2000 using better leak quantification methods show reciprocating compressor emissions five times higher than the GRI study. While not necessarily more representative of the gas processing sector or California, it does add to the body of data.

Recently published BP data (Gas STAR Partner Update Spring 2004) on gas well unloading in San Juan Basin supports earlier data made public by Mobil (Casper, Wyoming Gas STAR workshop, August 26, 1999), both examples showing that this source is underestimated in the GRI 1996 study by a factor of 10 or more. The analysis of well unloading data in the GRI study is illogical, attempting to relate well venting to well production rate, and the default emission factor can neither be reproduced from the data presented nor associated with the types of practices reported by Gas STAR Partners in well unloading. The Compendium default factor for this practice is not considered suitable for U.S., let alone California inventories.

The Compendium has simple default emission factors for offshore platforms derived from the 1996 GRI study. Recent U.S. Minerals Management Services (MMS) air emissions data gathered in the Gulf of Mexico show that offshore platform emissions are substantially higher than the GRI study. These data, analyzed and statistically evaluated to the same degree as GRI (Appendix B) and reported to the EPA, is showing average platform emissions 232% higher than GRI (compare U.S. Methane Inventory for 2004 with the inventory for 2003). This is of interest because California has a proportionately higher fraction of offshore to onshore emissions than the U.S. average as represented in the 1992 GRI study.

In summary of this section, while 90-plus percent of greenhouse gas emissions quantified by Compendium methods are well estimated, most of this being carbon dioxide from fuel combustion, the methane emissions that are most likely to be cost-effectively controllable (reference Lessons Learned studies posted on the Gas STAR website) are not estimated most accurately by the Compendium methods.

8. Recommendations and Conclusions

The critique in Section 7 above by no means is intended to discredit the monumental effort made in researching and assembling the Compendium, for methane largely based on the 1996 GRI/EPA study. Furthermore, this review and recommendations have nothing but the utmost respect for the underlying study commissioned by the Gas Research Institute (GRI) and U.S. Environmental Protection (EPA) and their several contractors. This has stood the test of time as being the world's most thorough, well researched, well analyzed and well documented studies on national emissions of methane from US natural gas industry. A companion study by ICF Consulting, commissioned by the EPA, serves as the best basis for methane emissions from the U.S. oil industry[12]. It is emphasized that this review has found many emissions source estimates to be acceptable, including the entire combustion emissions category. Nevertheless, in the course of developing the US national methane emissions inventories and projections for natural gas and petroleum systems, as well as the EPA's Natural Gas STAR Program for the past ten years, this reviewer has carefully examined most of the GRI/EPA study and published data to assure understanding and appropriate application of this study. The GRI/EPA study serves its intended purpose very well, that being, to characterize US national emissions.

These recommendations address improvements aimed not at national or state inventories, but at "entity" (company) inventories. Companies have two primary advantages over country-wide inventories: they know exactly what their facilities and operating practices are, and they have the ability to directly manage their emissions. A key concept in considering these improvements has been to push emissions estimation down to the equipment and technology level, where changes in operating practices or technology make a big difference in emissions. This would be considered a Tier 4 level inventory, where the GRI study factors would be considered Tier 3, as defined by IPCC guidelines. This review recommends Tier 4 level of detail to properly account for and track emission changes, year to year. Each section below addresses specific commentary on the Compendium from the critique in Sections 7 and 8, explaining any issues with the Compendium's emissions estimate and then recommending an alternative approach.

Finally, this review realizes that methane emissions estimation is still a maturing science, and no doubt the recommendations presented here can and will be improved with more and better data, alternative analytical approaches, peer review comments, and better understanding of actual sources and operations.

[12] EPA (1999). Estimates of Methane Emissions from the US Oil Industry (Draft Report). Office of Air and Radiation, US Environmental Protection Agency. October 1999.

8.1 Increased Transparency

The Compendium references GHGCalc® software documentation[13] for certain emission factors, particularly for fugitive emission factors. The software and its documentation require a user license, so it is not the most transparent reference for an inventory. This review attempted to obtain a copy of the stand-alone documentation, which details the derivation of emission factors, through Innovative Environmental Solutions (IES), and learned that it is not longer generally available. For some sources, GHGCalc® uses emission factors from the 1996 GRI/EPA study, and this primary source should be referenced directly instead of indirectly through GHGCalc®. EPA recently posted a link to the GRI/EPA 1996 study on the Gas STAR website: www.epa.gov/gasstar. For other sources referencing GHGCalc® documentation, where the values in the Compendium are not found in the 1996 GRI/EPA study, the documentation (or a license for GHGCalc®) would be required. For example, the GHGCalc® emission factor for plastic pipeline leaks has a different value and different units than the GRI/EPA emission factor (1,357 lb CH_4/mile-yr[14] versus 99,845 scf CH_4/leak-yr[15]). The methodology and rigor behind factors not in the GRI/EPA report is unknown without purchasing a user license to view the GHGCalc® documentation or API reprinting the stand-alone documentation.

Of the Compendium emission factors that cite the GHGCalc® documentation, those that API considered "insignificant" to a company's inventory have been aggregated to a more general average, but are derived from the 1996 GRI/EPA study. This substitutes API's unpublished notion of "significance" for the opportunity to include more specificity in a company (entity) inventory. Table 8 illustrates an example of how the Compendium reports aggregated GRI/EPA emission factors. For certain fugitive sources, the Compendium uses a national average rather than a regional average. Table 8 shows how some of the Compendium emission factors compare to the corresponding 1996 GRI/EPA factors (Table 6-3 in the Compendium, and Tables 5-2 and 5-3 in the 1996 GRI/EPA study.

The national factors in GHGCalc® are much smaller since the eastern U.S. data from GRI/EPA lower the average. A California inventory should, at a minimum, take advantage of GRI/EPA's western region factors, which are very different from GHGCalc®'s national factors. This example shows that GHGCalc® aggregates factors from different regions. In other tables, GHGCalc® aggregates different emissions sources, such as combining residential gas meter leaks and commercial/industrial gas meter leaks into a single meters source. We recommend that these be left as two separate, more specific sources. Finally, the U.S. National Methane Inventory for

[13] Shires, T.M. and C.J. Loughran. GHGCalc® Version 1.0 Emission Factor Documentation, Draft, Gas Technology Institute (GTI), January 2002.

[14] As referenced in the Compendium, Table 6-6, page 6-13

[15] Shires, T.M. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines.* Final Report, GRI-94/0257.26 and EPA-600/R-96-080i, Gas Research Institute and U.S. Environmental Protection Agency, June 1996. Table 8-2, page 39.

Table 8. Comparing GHGCalc® Documentation to the 1996 GRI/EPA Study

Fugitive Emissions Source	Units	GHGCalc® Emission Factor (national)[a]	1996 GRI/EPA Emission Factors (regional)[b]
Gas wellheads	scf CH4 / well-yr	8,208	eastern U.S.: 2,595 western U.S.: 13,302
Separators	scf CH4 / separator-yr	20,171	eastern U.S.: 328 western U.S.: 44,536
Gas Heaters	scf CH4 / heater-yr	20,978	eastern U.S.: 5,188 western U.S.: 21,066
Dehydrators	scf CH4 / dehydrator-yr	20,171[c]	eastern U.S.: 7,938 western U.S.: 33,262
Meters/Piping	scf CH4 / meter-yr	16,072	eastern U.S.: 3,289 western U.S.: 19,310
Small Gathering Compressors	scf CH4 / compressor-yr	97,043	eastern U.S.: 4,417 western U.S.: 97,729
Large Gathering Compressors	scf CH4 / compressor-yr	5.55x106	eastern U.S.: — western U.S.: 5.55x106
Large Gathering Compressor Stations	scf CH4 / station-yr	3.088x106	eastern U.S.: — western U.S.: 3.01x106

[a] Shires, T.M. and C.J. Loughran. GHGCalc® Version 1.0 Emission Factor Documentation, Draft, Gas Technology Institute (GTI), January 2002. Sections 4.2.1 and 4.3.1 (as referenced by the Compendium).

[b] Shires, T.M. Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks. Final Report, GRI-94/0257.25 and EPA-600/R-96-080h, Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] It is unknown if or how this dehydrator emission factor was derived from the 1996 GRI/EPA study data. The weighted average from eastern and western U.S. emission factors for dehydrators is 32,561 scf CH4 / dehydrator-yr.

Natural Gas and Petroleum System, 1990-2004 broke GRI eastern and western region activity factors into five NEMS regions (National Energy Modeling System), which will provide even more specificity for California inventories. The 1990-2005 inventory (currently under development) will further evaluate the GRI emission factors by the five NEMS regions, using data published in 1996 by GTI This information will be published in spring, 2007.

Recommendation: Increased Transparency

It is recommended that the 1996 GRI/EPA study be used in lieu of the GHGCalc® documentation wherever possible, both for increased transparency and increased accuracy. Wherever the Compendium cites GHGCalc® factors that are not found in the 1996 GRI/EPA documents, the Table 9 shows where the Compendium cites GHGCalc® documentation and shows any recommended replacements from the 1996

Table 9. Recommendations for Replacing GHGCalc® Documentation Sources

Compendium Table Referencing GHGCalc® Documentation	Page	Comment on GHGCalc® Emission Factors	Corresponding 1996 GRI/EPA Table	Volume / Page
Table 5-23	p. 5-86	Unknown how GHGCalc® factors in Table 5-23 were developed.	Table 6-1	Vol. 7 p. 39
Table 5-24	p. 5-87	Unknown how GHGCalc® factors in Table 5-24 were developed.	Table 6-1	Vol. 7 p. 39
Table 5-25	p. 5-90	GHGCalc® uses factors for dig-ins and pressure relief valves exactly as published in GRI/EPA. Unknown how the pipeline blowdown factor was developed.	Table 6-1	Vol. 7 p. 39
Table 6-1	p. 6-5	Unknown how GHGCalc® factors in Table 6-1 were developed. GHGCalc® has facility-level factors for onshore production and distribution pipelines, which have no comparable factor in the GRI/EPA study.	Table 5-4 Table 5-5 Table 5-6 Table 5-7	Vol. 8 p. 74 - 79
Table 6-3	p. 6-9	GHGCalc® aggregates regional factors.	Tables 5-2 and 5-3	Vol. 8, p. 74 - 75
Table 6-4	p. 6-11	Unknown how GHGCalc® factors in Table 6-4 were developed	Table 5-5	Vol. 8, p. 77
Table 6-5	p. 6-12	Unknown how GHGCalc® factors in Table 6-5 were developed. Table 6-5 has several sources that have no comparable factor in the GRI/EPA study.	Table 5-6 Table 5-7	Vol 8 p. 78 - 79
Table 6-6	p. 6-13	GHGCalc® aggregates gas meter sources. Unknown how other GHGCalc® factors in Table 6-6 were developed.	Table 5-9	Vol. 8, p. 81

GRI/EPA study. We recommend that if API intends to reference this former GRI documentation, they should obtain a copy, reprint it and make it available to the public.

8.2 Gas Sweetening Processes

Emission factors recommended by the Compendium in Table 5-4 are for a prevalent but specific type of gas sweetening using diethanol amine as a solvent. Other gas sweetening technologies in commercial use emit methane to the atmosphere at rates different than amine units and require different methodologies to estimate emissions.

Recommendation: Gas Sweetening Processes

Other liquid solvents are employed in a process similar to diethanol amine absorption, have a different affinity for methane, and result in different methane emissions. Solvent manufacturers can help quantify methane emissions for a specific process unit. Alternatively, solvent manufacturers may be able to express methane emissions from a specific solvent as a percentage of methane emissions from a comparable diethanol amine unit. For example, the Morphysorb® process results in methane emissions that are 66% to 75% lower than a diethanol amine process[16].

Other gas sweetening processes with potential methane vents can be optimized to find a use for the effluent stream containing the acid gases, usually by using the stream to supplement fuel gas. Emissions then become a matter of gas combustion, which should be included under the appropriate combustion source. These gas sweetening units, therefore, do not have any vented emissions but may have normal fugitive emissions potentially found in all process units.

The recommended approach for estimating emissions from non-amine gas sweetening is to consult operations staff or the process unit manufacturer. If the recommended approach is not feasible, default values are available for certain specific types of gas sweetening technologies. Table 10 shows emissions for several gas sweetening technologies but may not be comprehensive.

Table 10. Vented Emissions for Certain non-Amine Gas Sweetening Processes

Gas Sweetening Technology	Emission Factor
GTI & Uhde Morphysorb®	66% to 75% of Amine Unit Emission Factor
Engelhard Molecular Gate®	No methane is vented when effluent is used as fuel gas or flared 5% to 10% of methane in feed gas is vented if effluent not utilized
Kvaerner Membrane	No methane is vented when effluent is used as fuel gas 5% to 10% of methane in feed gas is vented if effluent not utilized

Source: "Acid Gas Removal Options for Minimizing Methane Emissions "presented at the Processors Technology Transfer Workshop, April 22, 2005, Oklahoma City, OK; Natural Gas STAR Program; United States Environmental Protection Agency. Available online at <www.epa.gov/gasstar>.

[16] "Acid Gas Removal Options for Minimizing Methane Emissions "presented at the Processors Technology Transfer Workshop, April 22, 2005, Oklahoma City, OK; Natural Gas STAR Program; United States Environmental Protection Agency. Available online at <www.epa.gov/gasstar>.

8.3 Dehydration Processes

Emission factors recommended by the Compendium in Tables 5-1 and 5-3 (not including Table 5-2 that has not been researched) are based on an analysis of process simulations presented in 1996 GRI/EPA. The simulations may be considered reasonable approximations, but the analysis is flawed and the single emission factor for all glycol dehydration units does not reflect the true operating characteristics of glycol dehydrators. The simulations fixed the ratio of glycol circulation to feed gas. Then the analysis "discovered" a direct relationship between methane emissions and feed gas flow rate. So the emission factor is a fixed value based on feed gas rate.

In fact, the emissions are in direct proportion to the glycol circulation rate. Because glycol dehydrator units are typically sized for design well flow rates, and flow typically declines over the life of the well, the glycol dehydrators become "over designed" as a reservoir matures. An excessive methane emissions operating practice identified by partner companies in the EPA's Natural Gas STAR Program is for the glycol circulation rate to be set at the maximum pump rate. Partners report finding circulation rates two and three times higher than an optimum rate (with methane emissions two to three times higher than necessary to meet pipeline moisture specifications. The Lessons Learned study (www.epa.gov/gasstar; "Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators") describes methods to cost-effectively reduce these excessive emissions.

A further problem with the 1996 GRI/EPA analysis is the use of a single, national average pressure for the single emission factor. Methane emissions are in direct proportion to the pressure in the gas/glycol contactor (or in the flash tank separator when present). Glycol dehydrators operate at pressures ranging from under 100 psig to over 900 psig. Using this single GRI/EPA emission factor could over or under estimate methane emissions by 100 to 300 percent.

For these reasons, Table 5-2 in the Compendium is not the most accurate methane emissions factor for individual company inventories. A general, national factor ignores important operating differences between industry sectors and geographic areas of the country.

Finally, emission factors recommended by the Compendium are for the most common technology using triethylene glycol as a solvent. Other gas dehydration technologies in commercial use emit methane to the atmosphere at rates different than glycol units and require different methodologies to estimate emissions. Again, Natural Gas STAR Program partners have reported switching to desiccant dehydration in certain regions of the country, a technology that not only reduces vented emissions of methane, but also avoids burning natural gas fuel and operating gas pneumatic control devices (www.epa.gov/gasstar: Lessons Learned study "Replacing Glycol Dehydrators with Desiccant Dehydrators").

Recommendation: Dehydration Processes

EPA presented at the 7th Annual Implementation Workshop (October, 2000) a paper outlining an alternative analysis of the process simulation runs in Volume 14, Table 5-2, page 17 of the 1996 GRI/EPA study. A methane emission correlation equation was developed from this data set, with methane emissions estimated for a glycol dehydrator as a function of the following parameters:

- glycol circulation rate,
- contactor pressure,
- flash tank pressure (if applicable), and
- inlet methane flow rate.

The recommended emission factor equation based on the GRI/EPA simulation runs is:

EF = 0.0066 x (Glycol Circulation Rate in gallons per hr)
x [IF Flash Tank Installed (FT Pressure, psia), ELSE: (Contactor Pressure, psia)]
x [IF: Gas Assist Pump Installed, (2.5), ELSE (1.0)]
+ [IF: Stripping Gas Used, (0.245), ELSE (0)]

This equation gives an emission factor in MMscf/yr methane per MMscf/day gas throughput of a glycol dehydrator, tailored to a company's operating conditions. The Annual Meeting audience of approximately 100 partner company representatives, including experts in GHG emissions estimation methodologies, gave this alternative approach their endorsement as an improvement on GRI/EPA. The equation could be re-evaluated and made more robust by using additional glycol unit simulations available from MMS as a part of the GOADS 2000 report.

For non-triethylene glycol dehydration processes, manufacturers are able to provide estimates of methane emissions from a specific process unit or quantify methane emissions as the percentage of emissions from a comparable glycol dehydrator unit. Specifically for the desiccant dehydration technology, the Natural Gas STAR Lessons Learned study provides methodologies for estimating methane emissions based on the size of the desiccant unit, the operating pressure and frequency of replacing the salt.

8.4 Pneumatic Devices

Table 5-15 of the API Compendium provides emission factors for pneumatic devices in various sectors. In the production sector, the main sources of data are the 1996

GRI/EPA study[17] and the CAPP[18] report. The GRI/EPA study makes no mention or accounting of a category of pneumatic devices called "low bleed" and therefore estimates methane emissions from pneumatic devices in the production sector without any delineation between high and low bleed devices. The Environmental Protection Agency (EPA) Natural Gas STAR program defines low bleed devices as those pneumatic devices that emit 6 scf/hr natural gas[19] or lower. Devices that emit more than 6 scf/hr fall in the high bleed category. This is an important classification since the ratio of high bleed to low bleed devices' population has significantly changed over time, with the industry adopting more low bleed devices. The GRI/EPA estimate is represented as being an average of such high and low devices as they existed in 1992/93, thus not reflecting the effects of this change on the emissions over time. Natural Gas STAR partner annual reports, plus pneumatic device equipment vendors sales data indicates that the ratio of high to low bleed devices has changed considerably over the past 10 years. We recently learned that low bleed devices have become so popular that the price is now lower than high bleed devices (further encouraging the industry to switch over, or buy lower emitting devices in new applications).

There are also some obviously erroneous and implausible numbers in the GRI/EPA estimate that render their analysis inaccurate. For example, Table 4-5 in the GRI/EPA report has the following wrong entries in it.

From Table 11 it is obvious that the count of "999" for snap acting devices is a wrong entry since the total count of devices is 3. This in turn renders the total count and the averages calculated at the end of the table wrong. Table 4-5 of the GRI/EPA report has other inaccurate entries, but the entire table is not reproduced here. It was suggested that this error is due to improper labeling of the table, and that the raw data used to derive the fractions is correct. However, the arithmetic in this table as shown, using the erroneous entry, appears to support the values reported at the bottom.

The factors in the Compendium's Table 5-15 derived from the CAPP report may not be suitable for California as the operating conditions in Canada are likely to be quite different due to the low temperatures. The Compendium's preferred approach to estimate pneumatic device emissions is to use site-specific device measurements or manufacturer data and only use Table 5-15 if necessary. While site-specific data will provide good emissions estimates, manufacturer data typically under-estimates emissions. Data reported by the EPA Natural Gas STAR Program on pneumatic devices[10] shows a comparison of manufacturer data with field performance.

[17] Shires, T.M. *Methane Emissions from the Natural Gas Industry, Volume 12: Pneumatic Devices.* Final Report, GRI-94/0257.29 and EPA-600/R-96-080l, Gas Research Institute and US Environmental Protection Agency, June 1996.

[18] Canadian Association of Petroleum Producers (CAPP), Calculating Greenhouse Gas Emissions, Table 1-12, Publication Number 2003-03, April 2003.

[19] Natural Gas STAR. *Lessons Learned – Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*, EPA430-B-03-004, Environmental Protection Agency

Table 11. Excerpt from Table 4-5, GRI/EPA Report

Site	Total Count of Devices	Power Media	No. of Snap-Acting Devices	No. of Throttling Devices	No. of Continuous Bleed Devices
7	3	Gas	999	0	0
Totals	4,204		2,574	1,630	1,463
Fraction by Device Type -	Non-continuous bleed: 0.65 ±43% Continuous bleed: 0.35 ±43%				

Source: Shires, T.M. *Methane Emissions from the Natural Gas Industry, Volume 12: Pneumatic Devices.* Final Report, GRI-94/0257.29 and EPA-600/R-96-080l, Gas Research Institute and US Environmental Protection Agency, June 1996. Table 4-5, page 44.

Recommendation: Pneumatic Devices

The emission factors provided in Table 5-15 of the Compendium for the production sector can be replaced by an emissions factor for high-bleed and another for low-bleed derived from the same data used by GRI/EPA to calculate their composite emission factors. The source data used to estimate the GRI/EPA emissions factors is valuable and can be used to derive emissions factors for high and low bleed devices. The following steps should be used to develop these emissions factors;

a) Study the data used by the GRI/EPA report to derive their emission factors for the production sector.
b) Cull out all erroneous/implausible numbers.
c) Assign data points to production and gathering/boosting sector.
d) Further classify data points into low and high bleed devices based on their bleed rates and using the definition given above.
e) Estimate emissions factors by using a weighted average of number of devices and bleed rates.

Expert judgment based on the typically larger number of devices at a gathering/booster station can be used in determining which of the data sites belong to production and which to gathering/boosting sectors of the industry. The following criteria will help in making the classification.

Using the approach above, emission factors for high and low bleed devices in the production and gathering-boosting sector can be calculated. It is recommended to replace the emission factors derived from the CAPP report with these newly calculated factors as they are likely to be more accurate and appropriate for the California operating conditions. Similar approach can be taken to estimate high- and low- bleed emission factors for the gas processing and transmission sectors.

The following factors derived in this manner are used in the U.S. EPA Methane Inventory for Petroleum Systems[20]:

f) Pneumatic Devices, High Bleed: 330 scfd CH4/device.
g) Pneumatic Devices, Low Bleed: 52 scfd CH4/device.

8.5 Well Tests and Blowdowns (When Not Flared)

Table 5-21 includes two emission factors for well clean-ups (also referred to as well tests and blowdowns), where a gas well is opened to the atmosphere to unload liquid accumulation that obstructs gas flow. One emission factor is from the 1996 GRI/EPA study, and the other is from a Canadian Petroleum Association study. The referenced 1996 GRI/EPA report uses incorrect methodology to arrive at its emission factor. The GRI/EPA methodology assumes a relationship between a gas well flow rate to the sales line and the quantity of gas vented to the atmosphere during unloading to derive their emission factor. The GRI/EPA methodology then scales the rate down with incompletely explained and apparently arbitrary factors of the percent of the year that flow will be 50% and 25% of full rate.

The GRI/EPA assumptions result in a blowdown estimate that is much less than the Natural Gas STAR partners have reported. For example, a Natural Gas STAR Program Lessons Learned study[21] includes published field data from 19 wells at Big Piney field in Wyoming. The field data includes measurements of actual blowdown rates rather than estimates of blowdown rates from the normal production. Table 12 shows that the measured blowdown rates are about 14 times higher than the rate calculated by the GRI/EPA study, i.e. 702 Mcf/yr compared to 49.570 Mcf/yr. Since the referenced 1992 Canadian Petroleum Association emission factor (11.582 Mcf/yr) is even less than that of the 1996 GRI/EPA value, it is also suspect.

In developing the above referenced Lessons Learned study, EPA, in consultation with partner companies who have measured well unloading rates and completely understand the operation, developed a method for estimating well venting based on practical logic about the process rather than trying to relate it to well flow rates (which there is no realistic relationship). This logic observes that, when a well has been obstructed with liquids and ceases producing gas, down-hole this is the same as shutting in the well at the surface. Below the column of liquid standing in the well tubing, the reservoir pressure increases to shut-in pressure, filling the annular volume of the casing outside

[20] *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003.* EPA 430-R-05-003. Annex 3, page 148, Table 3-53: CH4 Emissions from Petroleum Field Operations.

[21] "Installing Plunger Lift Systems in Gas Wells" Lessons Learned from Natural Gas STAR Partners. Natural Gas STAR Program, United States Environmental Protection Agency. Available online at <www.epa.gov/gasstar>.

Table 12. Vented Emissions for Gas Well Blowdowns

Well Number	Emission Volume for Gas Well Blowdowns (Mcf/yr/well)
1	1456
2	581
3	1959
4	924
5	105
6	263
7	713
8	453
9	333
10	765
11	1442
12	1175
13	694
14	1416
15	1132
16	1940
17	731
18	246
19	594
Big Piney, WY Average	702
Compare Final GRI Emission Factor	49.570

Assumes 78.8% methane by volume.

Adapted from: "Installing Plunger Lift Systems in Gas Wells" Lessons Learned from Natural Gas STAR Partners. Natural Gas STAR Program, United States Environmental Protection Agency. Available online at <www.epa.gov/gasstar>.

Final GRI Emission Factor taken from Shires, T.M. Methane Emissions from the Natural Gas Industry, Volume 7: Blow and Purge Activities. Final Report, GRI-94/0257.24 and EPA-600/R-96-080g, Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

the tubing with gas at shut-in pressure. This is exactly how a plunger lift system described in the Lessons Learned study works. Opening the well to the atmosphere removes the back pressure from the sales line and gives the volume of gas in the casing and in the reservoir immediately surrounding the perforations at shut-in pressure the energy necessary to push the liquids to the surface. Thus, a gas well blowdown occurs at a higher rate at the higher than normal pressure differential for a period of time, which is the driving force for expelling the liquid accumulation. During a blowdown, the high pressure gas accumulation in the casing is expended; flow rate

eventually reaches an equilibrium rate between the downhole flowing pressure and the atmosphere, which is still higher than the normal producing rate to the gas sales line. Under normal circumstances, the shut-in gas volume is sufficient to expel the liquid volume that stopped gas flow to the sales line.

Recommendation: Well Tests and Blowdowns (when not flared)

The Natural Gas STAR Program provides a method to estimate blowdown emissions from basic gas well and reservoir characteristics[11]. The method assumes that a well is blown down until the flow rate reaches an equilibrium, at which point the pressure is no longer sufficient to unload liquids, and the well is routed back to the sales line or is again shut in. The well dimensions and shut-in pressure are used to calculate a batch volume of gas in the well annulus that is vented to the atmosphere during a blowdown, and this volume is multiplied by the annual blowdown frequency. This engineering calculation is recommended in place of the well blowdown emission factors in Table 5-21 of the Compendium. Table 13 details the recommended method.

Table 73. Estimating Gas Well Blowdowns

Data required for each well: Casing Diameter (inches) Well Depth (feet) Shut-in Pressure (psia) Annual Number of Blowdowns
Equation: Annual Vent Volume (Mcf / yr) = 0.37 x 10-6 x Casing Diameter2 x Well Depth x Shut-in Pressure x Annual Number of Blowdowns
Adapted from: “Installing Plunger Lift Systems in Gas Wells” Lessons Learned from Natural Gas STAR Partners. Natural Gas STAR Program, United States Environmental Protection Agency. Available online at <www.epa.gov/gasstar>.

The recommended method to estimate blowdown venting calculates the minimum volume of gas that is vented. If a well is left open to the atmosphere for a period of time longer than required to depressure the annular space, the minimum volume can be increased by the ratio of actual vent time to minimum vent time. Calculating vent times can be accomplished through the Weymouth gas flow formula[22], which calculates gas flow rates, from which one can estimate the ideal vent time using the estimated vent volume.

We further recommend an emission factor based on the Big Piney, Wyoming actual data shown in Table 12 in place of the factor from GRI/EPA, should a company choose to use a default factor rather than gather the necessary data for the calculation

[22] McAlister, E. W., ed. Pipe Line Rules of Thumb Handbook, Fourth Edition, pages 281 – 284. 1998.

methodology in Table 13. While Big Piney data is just from one particular field, it compares better with the engineering calculation above than the value reported in GRI and the Compendium. The engineering calculation can be used on any gas well, including any California gas well.

8.6 Compressor Seals

The API Compendium lists fugitive methane emissions from compressors in Tables 6-3, 6-4 and 6-5 for production, processing and transmission sectors respectively. These compressor emissions include emissions from compressor seals, both reciprocating and centrifugal, and have been adapted from the 1996 GRI/EPA[23] study.

The 1996 GRI/EPA analysis estimates emissions from compressor seals as one national average number without any distinction between reciprocating and centrifugal compressor seals. The seals from the two types of compressors, centrifugal and reciprocating, vary significantly in terms of their emissions and therefore should not be treated as a single source for a company inventory. Some companies, and certain countries, who seek to use the API Compendium for emissions factor guidance, have all centrifugal compressors. The centrifugal compressor seals can be further classified based on the technology that they use to seal the rotating shaft at one or both ends of the compressor case. The more mature technology, wet seals (wet as in seal oil, not water) were in the majority in the natural gas industry at the time of the GRI/EPA study. Equipment vendors tell us that 90% of new compressors sold to this industry today have dry seals. The dry seals technology results in much lower emissions and lower operating costs as compared to wet seals. The EPA Natural Gas STAR Lessons Learned study[24] provides vendor design data for emissions from dry seals in mainline transmission compressors of 6 scf/min or lower. Emissions reported by Gas STAR partner companies from wet seals range from 40 to 200 scf/min. These two very different technologies emitting different levels of emissions have been lumped together in the 1996 GRI/EPA estimate of compressor seals emissions factor. Indeed, the composite compressor factor in GRI/EPA includes only a single data point for a dry seal compressor, the technology of choice today.

The centrifugal compressor wet seals use high pressure oil as a medium to seal the rotating shaft. This is a very good barrier to gas leakage at the seal face. However, the oil absorbs gas on the inboard side of the seal. The oil must be degassed to maintain its viscosity and lubricity before re-circulating to the sealing unit. The emission from the degassing unit is typically vented to the atmosphere in natural gas industry

[23] Shires, T.M. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks.* Final Report, GRI-94/0257.25 and EPA-600/R-96-080h, Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[24] Natural Gas STAR. *Lessons Learned – Replacing Wet Seals with Dry Seals in Centrifugal Compressors*, EPA430-B-03-012, Environmental Protection Agency

compressors, and need to be accounted for as emissions from seals. The 1996 GRI/EPA analysis is based on data gathered from an Indaco study[25]. In discussions with the individuals involved in measuring emissions as a part of this study, it was determined that the Indaco field measurements of emission from the compressor seals were made at the seal face, and did not include the emissions from degassing units. The degassing vents were measured along with all other vents, and combined in a compressor station vent emission factor. So it could be concluded that GRI/EPA suitably accounted for compressor station emissions in a national average, but the wet seal factor in GRI/EPA is not suitable for a company inventory.

Recommendation: Compressor Seals

The 1996 GRI/EPA analysis is based on the study conducted by Indaco. This study consists of detailed leak rates measured from the components at seventeen facilities. This good data base can be segregated on the basis of type of compressor, centrifugal and reciprocating. The dataset includes 116 measurements from reciprocating compressor seals. This is a good data size and the measurements fall well within the expected emissions value for reciprocating compressor seals. Therefore, an average of these leak rates can be used as an estimate of emissions factor for reciprocating compressor seals.

The measurement data for centrifugal compressors are not suitable. Moreover, the dataset includes just three measurements for centrifugal compressor seals, two for wet seals and one for dry seals, and does not include seal oil degassing emissions. Therefore, we recommend that data available from other sources noted below be used to estimate emissions from centrifugal seals, both wet and dry seals.

The EPA Natural Gas STAR Lessons Learned studies are a good source of data to establish emissions from centrifugal compressor seals. The lessons learned study dealing with economics of replacing wet seals with dry seals[24] provides leak rate information reported by Gas STAR partner companies on wet seals and from vendors on dry seals. This lessons learned also refers to an economic study conducted by Uptigrove et al.[26], which provides data that can be used to estimate emissions factors for centrifugal compressor seals. Another lessons learned study on taking compressors offline[27] provides data on emissions from compressors when they are offline, either pressurized or depressurized. These data were used by ICF Consulting to develop

[25] Howard, T. *Leak Rate Measurements at U.S. Natural Gas Transmission Compressor Stations*, GRI-94/0257.37, Indaco Air Quality Services, Inc., Gas Research Institute and U.S. Environmental Protection Agency

[26] Uptigrove, S. O., Harris, T.A., and Holzner, D. O. *Economic Justification of Magnetic Bearings and Mechanical Dry Seals for Centrifugal Compressors*. American Society of Mechanical Engineers Gas Turbine Conference and Exhibition. June 1987.

[27] Natural Gas STAR. *Lessons Learned –Reducing Emissions when taking Compressors off-line*, EPA430-B-04-001, Environmental Protection Agency

proprietary equations for emission factors for centrifugal compressors seals taking into account the on-stream factor and off-line operating condition.

More recently, a study conducted by Wuppertal Institute[28] at five gas compressor stations on the Russian Gazprom transmission system provides new measurement data on emissions from wet seals in centrifugal compressors. The author of the study confirms that the wet seal measurements include both the seal face and degassing unit emissions.

8.7 Distribution Pipeline Leaks

Tables 6-1 and 6-6 of the Compendium include distribution pipeline leak emission factors referenced from GHGCalc® documentation (which, as discussed above is not a transparent source). The factors in the Compendium are a composite of all types of distribution pipe, such as plastic, copper, cast iron, protected steel, and unprotected steel. The factors in the Compendium represent a national average of the population of pipe materials for the year the factors were developed and cannot account for the different regions and changing prevalence of pipe materials in an inventory time series. For example, plastic pipeline mileage is increasing, while cast iron pipeline mileage is decreasing. Furthermore, older cities have more cast iron pipe remaining in service while younger communities use the lower leaking materials. Thus, a company inventory based on t he different emission factors for each pipe material can more accurately account for the leak rates and the changes of pipe materials over time.

Recommendation: Distribution Pipeline Leaks

An alternative source is the 1996 GRI/EPA[29] estimate of fugitive emissions from underground pipelines. The GRI/EPA study provides separate emission factors for distribution mains and for distribution service pipelines, giving separate values for different material types. Because the Compendium proclaims its intent to “assemble an expansive collection of relevant emission factors for estimating GHG emissions, based on currently available public documents,” the 1996 GRI/EPA values are recommended as an optional methodology for pipeline leak emission factors in the Compendium, with the exception of the plastic distribution mains. Some companies may choose to estimate distribution pipeline emissions by miles of pipeline, and others by the number of discovered leaks. The remainder of this pipeline leak discussion explains the recommended factor for plastic distribution mains.

[28] Lechtenbohmer, S., and Dienst, C. *GHG Emissions of Russian Long Distance Gas Transport Pipelines – Options for Mitigation*. Wuppertal Institute.

[29] GRI-94/0257.26, EPA-600/R-96-080i, June 1996, *Methane Emissions from the Natural Gas Industry, Volume 9: Underground pipelines.* Table 9-1, page 54.

The plastic distribution mains emissions underlying the GRI/EPA factor includes six sample points. The six data points span five orders of magnitude from 0.008 scf/hr to 61 scf/hr. The 1996 GRI/EPA data points are listed in Table 14. Two of the data points appeared to be "outliers" because they are much higher than the other four. This was recognized by GRI/EPA, but there was not a legitimate basis upon which they could be rejected.

Table 14. GRI Data Points

Plastic Pipe Flow Rate (scf/leak-hr)
0.008
0.700
1.130
1.620
10.266
61.00
Mean: 12.454
Standard Deviation: 24.084

Shires, T.M. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines.* Final Report, GRI-94/0257.26 and EPA-600/R-96-080i, Gas Research Institute and U.S. Environmental Protection Agency, June 1996. Appendix A, Table A-2, page A-4.

A National Transportation Safety Board (NTSB) report[30] investigated the circumstances of certain incidents involving brittle cracking of plastic pipelines. Based on this report the Department of Transportation (DOT), Research and Special Programs Administration (RSPA) issued an advisory bulletin to owners and operators of natural gas distribution systems informing them about the susceptibility of plastic pipelines to brittle-like cracking and the need for voluntary data gathering. The NTSB report essentially highlights the fact that plastic pipelines manufactured by certain companies before year 1982 failed under service conditions. Elevated temperature testing demonstrated a rapid downturn in strength after the initial straight-line decrease in these pipelines. Brittle cracking occurs in this rapid downturn in strength.

The two high value points in the GRI/EPA collected dataset are suspected to be plastic pipes with leaks due to brittle cracking. This phenomenon is not widespread according to data gathered by American Gas Association (AGA)[31]. The revised ASTM D2837

[30] NTSB/SIR-98/01, Washington, DC, April 1998, National Transportation Safety Board (NTSB), *Brittle-Like Cracking in Plastic Pipe for Gas Service*.

[31] AGA – Plastic Pipelines Issue Summary (George Mosinskis (202) 824-7341)

standard[32] (updated 1988) for testing plastic pipes requires that polyethylene pipes display straight-line behavior in testing for 100,000 hours at 73˚F. This assures that PE pipe manufactured after 1988 does not exhibit the material deficiencies leading to the brittle failure. However, it is not known how much of the older, inferior plastic pipe was in service at the time the GRI/EPA data was collected, or how much remains in service today.

A Southern California Gas Company study[33] on un-accounted for gas in their operations provides seven additional data points of leak rates from plastic pipe. In 2005, EPA combined these new data points with the GRI/EPA data to develop more robust plastic pipe emission factors for the 2004 U.S. Methane Inventory for the Natural Gas Systems, which will be published in spring, 2006.

For company inventories, it is recommended that fugitive emissions from plastic piping be divided into two categories;

- *Early Plastic Pipe (Pre-1982)* – This applies to plastic pipe manufactured before 1982 and includes
  - polyethylene (PE) piping that has been identified by the U.S. National Transportation Safety Boards as susceptible to brittle cracking;
  - PE piping manufactured by Century Utility Products;
  - Pre 1973 DuPont Aldyl A;
  - Pipe containing PE 3306 resin;
  - Delrin insert tap tees;
  - Plexco service tee Celcon cap; and
  - Any PE material manufactured before the ASTM D2837 integrity standard.
- *Plastic Pipe ASTM D2837 (Post 1982)* – This piping is typically manufactured after 1982 and includes all plastic piping that meets an integrity standard defined by ASTM D2837.

The emissions factor for the two categories of plastic pipes was estimated using six GRI/EPA data points and seven SoCal data points. The emissions factor estimate for Early Plastic Pipe is the average of all 13 data points available from GRI and SoCal studies, assuming that the two out of thirteen outliers may be representative of the amount of inferior plastic pipe supplied to the industry prior to 1982. The emissions factor estimate for Plastic Pipe ASTM D2837 the two apparently failed samples in the GRI/EPA data set, assuming that the remaining four points and the seven data from SoCal represent typical joint and component leaks in good material plastic pipe. The leak rates are adjusted for methane content in pipeline gas and soil oxidation of natural gas leaks to finally estimate the emissions factors. The emissions factors for the two

[32] ASTM D2837: Standard Test Method for Obtaining Hydrostatic Design Basis for Thermoplastic Pipe Materials or Pressure Design Basis for Thermoplastic Pipe Products.

[33] Southern California Gas Company (SoCal), A study of the 1991 Unaccounted-for Gas Volume at the Southern California Gas Company. April 1993.

categories of plastic pipe fugitives are listed in Table 15. If a breakout of the plastic pipeline mileage in the two categories is not available, then the emissions factors estimate for Early Plastic Pipe may be conservatively applied to all plastic pipeline mileage.

Table 85. Emissions Factor Estimate for Plastic Pipes

Early Plastic Pipe			Plastic Pipe ASTM D2837		
Data Source	# Of Leaks	Leak Rate (scf/hr)	Data Source	# Of Leaks	Leak Rate (scf/hr)
GRI/EPA	1	0.008	GRI/EPA	1	0.008
GRI/EPA	1	0.700	GRI/EPA	1	0.700
GRI/EPA	1	1.130	GRI/EPA	1	1.130
GRI/EPA	1	1.620	GRI/EPA	1	1.620
GRI/EPA	1	10.266	SoCal[a]	7	1.200
GRI/EPA	1	61.000			
SoCal[a]	7	1.200			
Average Leak Rate (scf/hr)		6.394	Average Leak Rate (scf/hr)		1.078
Emissions Factor[a] (scf/hr)		5.85	Emissions Factor[b] (scf/hr)		0.99

[a] Southern California Gas Company (SoCal), A study of the 1991 Unaccounted-for Gas Volume at the Southern California Gas Company. April 1993.

[b]Leak Rate adjusted for methane content in natural gas of 93.4% and soil oxidation rate of 2%

8.8 Offshore Emissions Sources

The Compendium provides two emission factors explicitly for offshore oil and gas operations, emergency shut down (ESD) venting in Table 5-22 and fugitive emissions per platform in Table 6-1, both referenced to the 1996 GRI/EPA report. While GRI/EPA makes a clear distinction between oil operations and gas operations in Figure 3-2. Industry Boundaries, on page 7 of Volume 5 of the GRI/EPA report, they apparently do not follow this for offshore operations in Section 5.2, page 76 of Volume 8: “Half of the offshore platforms were allocated to the oil industry and, therefore, were not included within the boundaries of the gas industry.” Offshore oil platforms do have associated gas facilities, with gas emissions of a methane content quite different from natural gas production.

MMS published their most recent Gulfwide Offshore Air Data System (GOADS) data in 2004[34] . This is the most extensive and rich offshore database currently available, with the data collected in 2000. EPA analyzed this extensive database in the interest of improving the offshore methane emissions representation in the 2004 inventory (to be published in spring, 2006). One purpose of the EPA analysis was to be able to track changes in methane emissions over the inventory time series, from 1990 to 2004. By characterizing emissions by platform type (oil and gas) and water depth (greater or less than 200 meters of water depth), these offshore emission factors can depict the movement of production to deeper water and to gas as oil production is depleted.

The 1996 GRI/EPA study[35] estimates emissions from offshore platforms as an aggregate of emissions from four components on a platform; valve, connection, open-ended line, and other components. The study does not classify emissions from different equipments on the platforms. The Gulf of Mexico (GoM) and Pacific Outer Continental Shelf (POCS) are each represented by separate emissions factors and activity factors that are used to estimate emissions. The emissions factors and activity factors were developed using data from two studies; API/GRI study[36] of four offshore sites in the GoM and Minerals Management Service (MMS) study[37] of seven offshore production sites in POCS. The emissions factors and activity factors are listed in Table 16.

Table 96. Emissions Factors and Activity Factors for Offshore Platforms

Component Type	Emissions Factor (Mscf/ Component-yr)		Activity Factor (Average Component Count)	
	Gulf Of Mexico	Pacific OCS	Gulf Of Mexico	Pacific OCS
Valve	0.187	0.048	2207	1833
Connection	0.046	0.021	8822	13612
Open-Ended Line	0.368	0.092	326	313
Other	2.517	0.091	67	307

Note: “Other” category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents

[34] Wilson, D., Fanjoy, J., and Billings, R. *Gulfwide Emission Inventory Study for the Regional Haze and Ozone Modeling Efforts*. OCS Study MMS 2004-072, Minerals Management Service, October 2004.

[35] Shires, T.M. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks.* Final Report, GRI-94/0257.25 and EPA-600/R-96-080h, Gas Research Institute and US Environmental Protection Agency, June 1996.

[36] Star Environmental. *Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations*. API Publication Number 4589, American Petroleum Institute, December 1993.

[37] ABB Environmental Services. *Fugitive Hydrocarbon Emissions from Pacific OCS Facilities*. MMS Report 92-0043, U.S Department of Interior, Minerals Management Service, November 1992.

The emissions from each platform type, GoM and POCS, are estimated as the sum product of the emissions factors and activity factors. The emissions estimate for GoM and POCS platforms are 1,064 Mscf/platform-yr and 430 Mscf/platform-yr, respectively.

Recommendation: Offshore Emissions Sources

First, it is recommended here as in all sources to base company inventories at the lowest disaggregated source level rather than average platform factors. In the course of developing statistically representative emission factors for the four platform types, EPA determined detailed emission factors from specific point sources such as offshore dehydrator vents, offshore compressor blowdowns, offshore engine exhaust, offshore flaring, offshore mud degassing, component fugitives, etc. A company inventory comprised of specific offshore emissions sources allows the company to identify opportunities and methods to reduce emissions, and track changes. An inventory at the platform level does not facilitate emissions reduction tracking. Attachment A is an extract from the ICF report to EPA of offshore source specific emission factors derived from GOADS 2000 data.

The MMS study provides the following advantages over the EPA/GRI study;

a) The MMS study is a comprehensive study of all platforms in the GoM, while the EPA/GRI study sampled only four platforms.
b) The MMS study includes emissions from individual equipment, detail which is not available from EPA/GRI study.
c) The MMS study provides details of emissions from different technologies for the same type of equipment. For example, fugitives from centrifugal compressor seals are segregated into wet and dry seals technology.
d) Some sources like “drilling rigs” that have been obviously missed in the EPA/GRI study have been included in the MMS study.

ICF, under contract to the EPA, analyzed the emissions from individual sources and based on the results characterized the GoM offshore platforms into four distinct categories of platform emissions. The platforms are segregated based on platform water depth and type of production, oil or gas. ICF estimated emissions by using activity data from MMS GOADS study and replaced in certain cases MMS emissions factors by better estimates from other studies. The four types of platform sources and their corresponding emissions factors are listed in Table 17. Appendix B shows the detailed listing of sources for each platform grouping, with methane emissions determined from the GOADS reported data for those platforms.

These emissions factors are significantly higher than those estimated by the EPA/GRI study. Since the estimates were developed using more, better and transparent data it is recommended that the MMS GOADS data analysis estimates be used for emissions from offshore platforms as alternatives to the single GRI platform factor. The applicability of the GoM MMS data and analysis to California offshore platforms has not been studied.

Table 107.Offshore Platform Emission Factors from GOADS 2000

Platform Source	Emissions Per Platform (Bcf)
Deep Water Gas Platforms	0.029
Shallow Water Gas Platforms	0.007
Deep Water Oil Platforms	0.095
Shallow Water Oil Platforms	0.020

8.9 Combined Heat and Power Operations

The Compendium calculates four types of emissions from Combined Heat and Power (CHP): direct combustion emissions from fuel consumption, emissions from electricity generation, emissions from steam generation, and indirect emissions associated with electricity sold to the grid. Emissions from electricity and steam production are a portion of the direct emissions from fuel consumption; therefore, the total of the two emissions quantities from electricity and steam will never be greater than the direct emissions total. Indirect emissions are calculated using simple ratios of steam generation in conjunction with the direct combustion emission totals.

The scope of this report requires commentary on various approaches to estimation and allocation of GHG emissions associated with CHP operations. The Compendium calculates direct combustion (on-site) emissions for CO_2, CH_4 and N_2O with AP-42 emission factors. The Compendium has the intent to "assemble an expansive collection of relevant emissions factors …" and thereby should incorporate all methodologies, leaving it to the user to choose one that they can apply with data reasonably available. Therefore, for allocation of CHP CO_2 emissions between electricity and steam, the Compendium presents four methods:

- UK Emissions Trading Scheme,
- WRI/WBCSD GHG Protocol Initiative,
- California Climate Action Registry, and
- Work Potential Allocation Approach.

The UK emissions Trading Scheme approach bases its allocation on the assumption that the efficiency of heat generation is twice that of electricity generation. The approach applies to emissions associated with the direct import/export of electricity from a CHP facility.

The WRI/WBCSD GHG Protocol Initiative presents a different efficiency allocation approach, where the efficiencies of typical heat and power production are not derived from one another. Instead, they are measured or assumed to be two separate quantities. The WRI/WBCSD approach uses measurable quantities to calculate emissions. The calculations come from heat output, electricity output, and their

respective efficiencies. All of these quantities can be either measured directly or easily calculated from other measurable quantities onsite. This method can be site-specific if using the measurable data for that plant or, if needed, regional outputs and efficiencies can be calculated.

The California Climate Action Registry attributes emissions to heat and electricity production based on a ratio of the energy produced for each type (heat or steam) to the total energy produced (net heat generation plus electricity generation). This approach is similar to the WRI/WBCSD approach except that the California approach assumes the efficiency is the same for both net heat production and electricity production.

The Work Potential Allocation Approach assigns the emissions to the energy streams in proportion to their contribution to the total work potential, or energy. The work potential for steam is calculated form the specific enthalpy and specific entropy of the stream. This approach sums the work potential of all streams and allocates the total emissions to the individual streams. This approach is the most extensive, which uses the properties of steam to calculate the combustion emissions; however, accurate steam temperatures are needed to do these calculations.

8.10 Missing Sources

This section discusses omissions from the Compendium which may be of interest to a company desiring to develop a rigorous GHG inventory. The Compendium does not include any specific written guidance on the emissions sources listed in Table 18. For the sake of completeness, the sources not specifically listed by the Compendium are provided in Table 18.

The following provides more description of a selection of the sources in Table 18 not specifically included in the Compendium that ICF believes ought to be included in a CCAR protocol.

- CO_2 venting from EOR operations (both vent and fugitive)

  IPCC 2006 guidelines are attempting to address EOR inventory issues, as is the EPA in its national CO_2 inventory. While all source and emission factors have not yet been decided, this is expected to be a significant source, growing in the future as US crude oil reserves mature and EOR becomes more widespread. CO_2 sequestration is an important part of this issue.

Table 18. Sources Absent from the Compendium

Missing Source	Remarks
Fuel for portable/backup/emergency engines, generators, fire pumps, etc.	These sources of fuel combustion are not explicitly listed but can fall into some general existing combustion source categories in the Compendium. For international audiences, more examples of specific sources aides understanding.
Fuel for plant maintenance e.g. welding and cutting	
Tugs	
Standby vessels	
Supply vessels	
Other ships	
Incineration of waste material/by-products	Off-site waste incineration can be a significant indirect source.
Accidental or training fires	
Fire fighting equipment	
Construction operations	This source of fuel combustion is not explicitly listed but can fall into some general existing combustion source categories. Identification of this source aides understanding of the Compendium's application.
CO_2 well stimulation	
Oil well completion venting	
Gas well completion venting	
Mud degassing	
Gas dehydration from non-glycol processes	The Compendium only provides guidance on glycol dehydration.
Gas sweetening from non-amine processes	The Compendium only provides guidance on amine gas sweetening.
Oil pipeline pigging	
Gas pipeline pigging	This source is listed in the Compendium as a composite factor with other activities. Pigging should be a separate source for the Gathering/Booster and Transmission sectors because of its routine nature and amenability to emission reductions.
Drips	
Sources listed in Table 18 should be included in a GHG inventory.	

- Gas well completion venting or flaring:

Well completions and workovers involve a number of activities that result in gas vented or flared to the atmosphere, mainly opening the well to a flare or the atmosphere to measure its maximum production rate and to expel drilling fluids, water, sand, mud, cutting fines to clean-up the product suitable for sales. The Compendium does not include a methodology to estimate emissions from gas well completions, while the 1996 GRI/EPA study provides an emission factor only for

unburned methane from completion flaring (733 scf CH_4 / well completion)[38]. British Petroleum, Williams and Devon (among other Gas STAR Partners) have reported a practice called "Green Completions" or "Reduced Emissions Completions" with significant methane emission reductions from the practice of venting and flaring. Such large reported emissions reductions pre-suppose even larger emissions before applying these practices.

- Drilling mud degassing:

  One component of well drilling is using drilling mud to prevent oil and/or gas from flowing before a well is completed. Methane becomes absorbed in the mud, which is released to the atmosphere when the mud is degassed at the surface. The Compendium has not included this potential emissions source, and the 1996 GRI/EPA study also excluded this source from its report. A 1977 EPA study[39] includes emission factors for two types of drilling muds, water-based and oil-based. The emission factors are used to estimate Gulf of Mexico offshore emissions in federal waters in a recent Mineral Management Service (MMS) study[40]. A third type of drilling mud, synthetic, is assumed by the MMS study to have similar emission characteristics to that of oil-based muds. Table 19 shows the three mud types and their degassing emission factors. The factors estimate THC emissions and should be converted to a methane emissions basis based on the methane content of the gas.

Table19. Recommended Mud Degassing Emission Factors

Emission Source	Emission Factor	Units
Mud degassing – water-based mud	881.84	lbs THC / drilling day
Mud degassing – oil-based mud	198.41	lbs THC / drilling day
Mud degassing – synthetic mud	198.41	lbs THC / drilling day

"Atmospheric Emissions from Offshore Oil and Gas Development and Production," EPA, 1977.
Assume synthetic mud has similar emission characteristics to oil-based mud
Apply the appropriate mass or volume percentage methane to the mud degassing emission factors. The 1996 GRI/EPA study uses 78.8% methane by volume as a default percentage.

[38] Shires, T.M. *Methane Emissions from the Natural Gas Industry, Volume 7: Blow and Purge Activities*. Final Report, GRI-94/0257.24 and EPA-600/R-96-080g, Gas Research Institute and U.S. Environmental Protection Agency, June 1996. Table 5-9, page 31.

[39] "Atmospheric Emissions from Offshore Oil and Gas Development and Production," EPA, 1977.

[40] Wilson, Darcy, et. al. "Gulfwide Emission Inventory Study for the Regional and Ozone Modeling Efforts," Mineral Management Service. MMS 2004-072. October, 2004.

Developing a greenhouse gas inventory and estimating emissions is not yet a mature practice. Much has been learned since the 1996 GRI/EPA monumental study was published. Once focused on methane emissions in particular, which having been unregulated, invisible and odorless, the U.S. EPA and its Natural Gas STAR Program partner companies have identified many ways to reduce emissions, some from sources not identified before the program inception in 1993. It is considered a good practice to provide guidance to companies embarking on greenhouse gas inventories that the list of sources is probably not comprehensive. Companies should give their field operators, engineers and maintenance personnel an invitation to bring to management attention any source of greenhouse gas emissions not identified in an inventory protocol, and in the API Compendium.

Appendix A. Evaluation Matrix

Evaluation of API Compendium Applicability for the California Petroleum and Natural Gas Industries			
Industry Sector and Source	**Applicable Methods Listed In API Compendium**	**API Comp-endium Section**	**Remarks on technique, methodology, strengths, and weaknesses**
Exploration and Production — combustion sources			
Boilers/Steam Generators		4.1, 4.2, 4.3	The Compendium methods for combustion emissions are acceptable.
Heaters/Treaters		4.1, 4.2, 4.3	
Internal Combustion Engines		4.1, 4.2, 4.3	
Turbines		4.1, 4.2, 4.3	
Flares		4.4	
Incinerators		4.6	
Planes/helicopters		4.5	
Supply boats, barges		4.5	
Other company vehicles		4.5	
Electricity imports		4.7	
Process heat/steam imports		4.7	
Exploration and Production - vented sources			
Gas Sweetening Processes	Simulation with process data	5.1.3	This yields good accuracy, provided aggregate, representative data is collected on company-wide applications. Usually not the method of choice.
	EF based on equipment throughput, non-sector specific	5.1.3	**(Table 5-4):** This table is appropriate for only amine gas sweetening technology. More recent gas sweetening technologies (Selexol, Morphysorb, Pressure Swing Adsorption, and Membranes) are now in commercial use and have significantly different methane emissions. The factors in this table are acceptable for gas sweetening specifically by amine units. The emission factors are based on process simulations roughly a decade old.

Evaluation of API Compendium Applicability for the California Petroleum and Natural Gas Industries				
Industry Sector and Source		**Applicable Methods Listed In API Compendium**	**API Comp-endium Section**	**Remarks on technique, methodology, strengths, and weaknesses**
		EF based on equipment count	5.1.3	**(Table 5-4):** This table is appropriate for only amine gas sweetening technology. More recent gas sweetening technologies (Selexol, Morphysorb, Pressure Swing Adsorption, and Membranes) are now in commercial use and have significantly different methane emissions. The factors in this table are acceptable for gas sweetening specifically by amine units. The emission factors are based on process simulations roughly a decade old.
	Dehydration processes	Direct measurement	5.1.1	Direct measurement of emissions is always best, but rarely practical for actual emissions to the atmosphere.
		Simulation with process data	5.1.1	This yields good accuracy, provided aggregate, representative data is collected on company-wide applications. Usually not the method of choice.
		EF based on equipment throughput, sector specific	5.1.1	**(Table 5-1 and 5-3):** These tables contain unacceptable emission factors. The GRI simulation analyses were improperly analyzed, and the conclusions do not reflect true operating and methane emission characteristics of glycol dehydrators.
		EF based on equipment throughput, non-sector specific	5.1.1	**(Table 5-2):** This table is not the most appropriate. By giving general instead of sector-specific factors, an important parameter for methane emissions is ignored. Gas pressure in the contactor or flash tank separator has a large influence on the resulting methane emissions from glycol dehydrators, and gas pressure varies widely between sectors and even production fields.
	Tanks	Direct measurement	5.4.1 page 5-32 5.4.3 page 5-46	Direct measurement of emissions is always best, but rarely practical for actual emissions to the atmosphere.
		Simulation with process data	5.4.1 page 5-33 5.4.3 page 5-46	This yields good accuracy, provided aggregate, representative data is collected on company-wide applications. Usually not the method of choice.

Evaluation of API Compendium Applicability for the California Petroleum and Natural Gas Industries				
Industry Sector and Source		**Applicable Methods Listed In API Compendium**	**API Comp-endium Section**	**Remarks on technique, methodology, strengths, and weaknesses**
		Correlation equations	5.4.1	**(Vasquez-Beggs Equation), (Standing Correlation), (EUB Rule-of-Thumb):** These methods are acceptable for uncontrolled emissions, provided field data is aggregated for typical production characteristics (API gravity, separator pressure)
		EF based on equipment throughput, non-sector specific	5.4.1 5.4.3	**(Table 5-6):** Acceptable **(Table 5-8):** Acceptable **(Table 5-9):** Acceptable: same order of magnitude as the low pressure (50 psi) factor in Table 5-8
		Assume Negligible	5.4.2	Acceptable for the working/standing losses only if separately accounting for tank flashing losses.
		Engineering Calculation	5.4.2	**Chapter 7 of AP-42 and TANKS software:** Acceptable if separately accounting for tank flashing losses.
		Material Balance	5.4.4	This yields good accuracy for individual tanks and when the data can be obtained and aggregated for multiple tanks with similar characteristics.
	Pneumatic devices	Direct measurement	5.6.1	Direct measurement of emissions is always best, but rarely practical for actual emissions to the atmosphere. Direct measurement of supply gas to multiple pneumatic devices at a site it best when taken over a representative operating period of time.
		Manufacturer Data	5.6.1	This approach will under-estimate emissions. Data reported by the EPA Natural Gas STAR Program (www.epa.gov/gasstar) in a Lessons Learned document on pneumatic devices shows that manufacturer data on emissions is typically much lower than field performance.

Evaluation of API Compendium Applicability for the California Petroleum and Natural Gas Industries				
Industry Sector and Source		**Applicable Methods Listed In API Compendium**	**API Comp-endium Section**	**Remarks on technique, methodology, strengths, and weaknesses**
		EF based on equipment count	5.6.1	**(Table 5-15):** This table uses factors from the 1996 GRI/EPA report, which aggregates many types of devices: high-bleed and low-bleed continuous and intermittent-bleed type devices. If a company's mix of pneumatic devices similar to the GRI data collected in 1992-93, then these factors would be satisfactory. However, vendor sales data shows that low-bleed devices have significantly penetrated the industry over the past decade, gradually replacing older, high-bleed devices and is the technology of choice for new installations. Factors taken from the 2003 CAPP report are not recommended. The 2003 CAPP report collected data on out-dated high-bleed devices that are operating in an environment much different than California.
	Chemical injection pumps	Direct measurement	5.6.2	Direct measurement of emissions is always best, but rarely practical for actual emissions to the atmosphere from large numbers of devices.
		Manufacturer Data	5.6.2	This has uncertain accuracy because, like pneumatic valve controllers, vendor data represents emissions in a new device, and no studies have been made comparing actual emissions of units in the field with vendor data. It may be impractical collecting data characterizing a large number of injection pumps by make, model and operating scenario.
		EF based on equipment count	5.6.2	**(Table 5-16):** Acceptable
	Well Testing	Material Balance	5.6.3	Coal associated factors are insignificant for California.
	Exploratory Drilling	Material Balance	5.6.3	Coal associated factors are insignificant for California.
	Other Venting Sources: Casing Gas	EF based on throughput and equipment count	5.6.4	**(Tables 5-17 and 18)**: Acceptable
	Other Vented Sources: CO_2 Venting from Sour Gas Processing	Material Balance	5.1.4	Acceptable
	Vessel Blowdown	EF based on equipment count	5.7.2	**(Table 5-21):** Acceptable

Evaluation of API Compendium Applicability for the California Petroleum and Natural Gas Industries				
Industry Sector and Source		**Applicable Methods Listed In API Compendium**	**API Comp-endium Section**	**Remarks on technique, methodology, strengths, and weaknesses**
		Engineering Calculation	5.7.1	This yields good accuracy when data is collected and aggregated for typical operating characteristics. Uncertain that referenced 2002 CAPP report would be applicable to California.
	Well Workovers	EF based on equipment throughput, sector specific	5.7.2	**(Table 5-21):** Need to investigate and understand the referenced data (1990 Pipeline Systems Inc report) to comment.
		Engineering Calculation	5.7.1	This yields good accuracy when data is collected and aggregated for typical operating characteristics. Uncertain that referenced 2002 CAPP report would be applicable to California.
	Compressor Starts	EF based on equipment count	5.7.2	**(Table 5-21):** Acceptable
		Engineering Calculation	5.7.1	This yields good accuracy when data is collected and aggregated for typical operating characteristics. Uncertain that referenced 2002 CAPP report would be applicable to California.
	Compressor Blowdowns	EF based on equipment count	5.7.2	**(Table 5-21):** Acceptable
		Engineering Calculation	5.7.1	This yields good accuracy when data is collected and aggregated for typical operating characteristics. Uncertain that referenced 2002 CAPP report would be applicable to California.
	Gathering Pipeline Blowdowns	EF based on equipment count	5.7.2	**(Table 5-21):** Acceptable
		Engineering Calculation	5.7.1	This yields good accuracy when data is collected and aggregated for typical operating characteristics. Uncertain that referenced 2002 CAPP report would be applicable to California.
	Pressure Relief Valves (PRVs)	EF based on equipment count	5.7.2	**(Table 5-22):** Acceptable
	Well tests and blowdowns (when not flared)	EF based on equipment count	5.7.1	**(Table 5-21):** This source is referred to as well clean-ups in Table 5-21. The referenced 1996 GRI/EPA report uses incoherent logic to arrive at its emission factor. Published field data indicate that the 1996 GRI/EPA factor is unacceptably low. Since the referenced 1992 CAPP well clean-ups finding is even less than that of the 1996 GRI/EPA value, it is also an unacceptably low estimate of methane

Evaluation of API Compendium Applicability for the California Petroleum and Natural Gas Industries			
Industry Sector and Source	**Applicable Methods Listed In API Compendium**	**API Comp-endium Section**	**Remarks on technique, methodology, strengths, and weaknesses**
			emissions from this source.
Emergency shutdown (ESD)/ emergency safety blowdown (ESB)	EF based on equipment count	5.7.2	**(Table 5-22):** This factor is only valid for an offshore facility.
Exploration and Production - Fugitive Sources			
Equipment Component Leaks	Direct measurement (LDAR)	6.1 page 6-2	Direct measurement of emissions is always best, but rarely practical for actual emissions to the atmosphere.
	Facility-level average emission factors, sector-specific	6.1.1	**Table 6-1:** Emission factors in this table are temporarily acceptable, although derived from over ten year old data and less accurate measurement techniques. Extensive new data is coming available for offshore production and gas processing, using better screening and mass emissions testing methods and more extensively sampling the industry. The 1996 GRI study, and the Compendium classify gas gathering/boosting stations under the production sector, which distorts production averages and does not correctly represent gathering/boosting factors in Table 6-1. The pipeline leaks source should be investigated to understand the types of pipe that were included in the study; pipe material is a primary indicator of emissions.

Evaluation of API Compendium Applicability for the California Petroleum and Natural Gas Industries			
Industry Sector and Source	**Applicable Methods Listed In API Compendium**	**API Comp-endium Section**	**Remarks on technique, methodology, strengths, and weaknesses**
	Equipment level average emission factors, sector specific	6.1.2	**Table 6-2:** EPA document 600/R-99-010 was never issued as a final report, and subsequently revised, so this reference is invalid. **Table 6-3:** Conditionally acceptable. The GHGCalc reference is obtainable only by licensing the software. Since GHGCalc is based on the 1996 EPA/GRI study, reference the primary study is necessary to validate the factors.**Table 6-4:** Conditionally acceptable. The GHGCalc reference is only obtainable by licensing the software. Since GHGCalc is based on the 1996 EPA/GRI study, reference the primary study is necessary to validate the factors.
Coal Bed Methane Production - Combustion			Coal Bed Methane Not Applicable in California
Coal Bed Methane Production - Vented Sources			Coal Bed Methane Not Applicable in California
Coal Bed Methane Production - fugitive sources			Coal Bed Methane Not Applicable in California
Minerals and Mining Operations - combustion			Minerals and Mining are not part of the natural gas and oil sector
Minerals and Mining Operations - vented sources			Minerals and Mining Operations are not part of the natural gas and oil
Transportation and Distribution - Combustion			
Turbines		4.1, 4.2, 4.3	The Compendium methods for combustion are acceptable.
Engines		4.1, 4.2, 4.3	
Heaters		4.1, 4.2, 4.3	
Flares		4.4	
Catalytic and thermal oxidizers		4.6	
Marine, road, or railroad tankers		4.5	
Barges		4.5	
Planes/helicopters		4.5	
Other company vehicles		4.5	
Electricity imports		4.7	
Process heat/steam imports		4.7	
Transportation and Distribution - Vented Sources			

Evaluation of API Compendium Applicability for the California Petroleum and Natural Gas Industries			
Industry Sector and Source	**Applicable Methods Listed In API Compendium**	**API Comp-endium Section**	**Remarks on technique, methodology, strengths, and weaknesses**
Storage tanks	Assume Negligible	5.4.2	Acceptable for the working/standing losses.
	Simulation with process data	5.4.2	**Chapter 7 of AP-42 and TANKS software:** Acceptable.
Loading/unloading/transit	EF based on equipment throughput, sector specific	5.5.1	**(Table 5-10):** Conditionally acceptable. Note this is a TOC factor Footnote a is not correct. AP-42 makes it clear that the 15% non-VOC hydrocarbon is methane AND ethane, so the assumption of 15% methane is too conservative. **(Table 5-11):** Note this is a TOC factor
	EF based on equipment throughput, sector specific	5.5.2	**(Table 5-12):** Conditionally acceptable. Note this is a TOC factor Footnote a is not correct. AP-42 makes it clear that the 15% non-VOC hydrocarbon is methane AND ethane, so the assumption of 15% methane is too conservative. **(Table 5-13):** Not applicable; GHG emissions from gasoline are insignificant.
	EF based on equipment throughput, sector specific	5.5.3	**(Table 5-14):** Conditionally acceptable for Crude Oil. Note this is a TOC factor Footnote a is not correct. AP-42 makes it clear that the 15% non-VOC hydrocarbon is methane AND ethane, so the assumption of 15% methane is too conservative.
Pneumatic devices	Direct measurement	5.6.1	Direct measurement of emissions is always best, but rarely practical for actual emissions to the atmosphere. Direct measurement of supply gas to multiple pneumatic devices at a site it best when taken over a representative operating period of time.
	Manufacturer Data	5.6.1	This approach will under-estimate emissions. Data reported by the EPA Natural Gas STAR Program (www.epa.gov/gasstar) in a Lessons Learned document on pneumatic devices shows that manufacturer data on emissions is typically much lower than field performance.

Evaluation of API Compendium Applicability for the California Petroleum and Natural Gas Industries				
Industry Sector and Source		**Applicable Methods Listed In API Compendium**	**API Comp-endium Section**	**Remarks on technique, methodology, strengths, and weaknesses**
		EF based on equipment count	5.6.1	**(Table 5-15):** This table uses factors from the 1996 GRI/EPA report, which aggregates many types of devices: high-bleed and low-bleed continuous and intermittent-bleed type devices. If a company's mix of pneumatic devices similar to the GRI data collected in 1992-93, then these factors would be satisfactory. However, vendor sales data shows that low-bleed devices have significantly penetrated the industry over the past decade, gradually replacing older, high-bleed devices and is the technology of choice for new installations. Factors taken from the 2003 CAPP report are not recommended. The 2003 CAPP report collected data on out-dated high-bleed devices that are operating in an environment much different than California.
	Pipeline blowdowns	EF based on equipment throughput, sector specific	5.7.4 5.7.5	**(Table 5-24):** Conditionally acceptable. **(Table 5-25):** Conditionally acceptable. The GHGCalc reference is obtainable only by licensing the software. Since GHGCalc is based on the 1996 EPA/GRI study, reference the primary study is necessary to validate the factors.
	Pigging Operations	EF based on equipment throughput, sector specific	5.7.4	**(Table 5-24):** Conditionally acceptable. The GHGCalc reference is obtainable only by licensing the software. Since GHGCalc is based on the 1996 EPA/GRI study, reference the primary study is necessary to validate the factors. Pigging is under the "Gas transmission pipelines venting/ blowdowns" source. If using this factor, do not use this source once for pipeline blowdowns and again for pigging; use only once.
	Compressor Starts	EF based on equipment count	5.7.2	**(Table 5-21):** Conditionally Acceptable. CH4 content is appropriate for upstream only. Transmission CH4 content is significantly higher.
		Engineering Calculation	5.7.1	This yields good accuracy when data is collected and aggregated for typical operating characteristics. Uncertain that referenced 2002 CAPP report would be applicable to California.
	Compressor Blowdowns	EF based on equipment count	5.7.2	**(Table 5-21):** Conditionally Acceptable. CH4 content is appropriate for upstream only. Transmission CH4 content is significantly higher.
		Engineering Calculation	5.7.1	This yields good accuracy when data is collected and aggregated for typical operating characteristics. Uncertain that referenced 2002 CAPP report would be applicable to California.

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Industry Sector and Source		Applicable Methods Listed In API Compendium	API Comp-endium Section	Remarks on technique, methodology, strengths, and weaknesses
	Compressor station blowdowns	EF based on equipment count	5.7.4	**(Table 5-24):** Conditionally acceptable. The GHGCalc reference is obtainable only by licensing the software. Since GHGCalc is based on the 1996 EPA/GRI study, reference the primary study is necessary to validate the factors.
	Vessel Blowdown	EF based on equipment count	5.7.2	**(Table 5-21):** Conditionally Acceptable. CH4 content is appropriate for upstream only. Transmission CH4 content is significantly higher.
		Engineering Calculation	5.7.1	This yields good accuracy when data is collected and aggregated for typical operating characteristics. Uncertain that referenced 2002 CAPP report would be applicable to California.
	Pressure relief valves	EF based on equipment count	5.7.4 5.7.5	**(Table 5-24):** Conditionally acceptable. The GHGCalc reference is obtainable only by licensing the software. Since GHGCalc is based on the 1996 EPA/GRI study, reference the primary study is necessary to validate the factors. This source includes vents from all station activities, not just PRVs. **(Table 5-25):** Conditionally acceptable. The GHGCalc reference is obtainable only by licensing the software. Since GHGCalc is based on the 1996 EPA/GRI study, reference the primary study is necessary to validate the factors.
	Surge tanks	Correlation equations	5.7.4	**(Vasquez-Beggs Equation),** **(Standing Correlation),** **(EUB Rule-of-Thumb):** Unacceptable. All three of these methods is based on a delta pressure between the last equilibrium stage in volatile liquid separation. Since that last separation was in the production tank, at atmospheric pressure, the delta pressure is zero, and flashing losses would be determined to be zero by each method.
Transportation and Distribution — fugitive sources				
	Process equipment leaks	Facility-level average emission factors, sector-specific	6.1	**(Table 6-5):** Conditionally unacceptable. The GHGCalc reference is obtainable only by licensing the software. Since GHGCalc is based on the 1996 EPA/GRI study, reference the primary study is necessary to validate the factors. The 1996 GRI centrifugal compressor seal emissions data is flawed because the wet seal compressor data ignored the seal oil degassing emissions, which are orders of magnitude higher than the emissions measured at the seal

Evaluation of API Compendium Applicability for the California Petroleum and Natural Gas Industries

Industry Sector and Source		Applicable Methods Listed In API Compendium	API Comp-endium Section	Remarks on technique, methodology, strengths, and weaknesses
				face.
		Equipment level average emission factors, sector specific	6.1	**(Table 6-5):** Acceptable. The GHGCalc reference is only obtainable by licensing the software. Since GHGCalc is based off of the 1996 EPA/Radian study, reference the study to improve the transparency of an inventory. *what are compressor fugitives made of?
	Pipeline leaks	Facility-level average emission factors, sector-specific	6.1	**(Table 6-5):** Conditionally acceptable. The GHGCalc reference is obtainable only by licensing the software. Since GHGCalc is based on the 1996 EPA/GRI study, reference the primary study is necessary to validate the factors.
		Equipment level average emission factors, sector specific	6.1	**(Table 6-5):** Conditionally acceptable. The GHGCalc reference is obtainable only by licensing the software. Since GHGCalc is based on the 1996 EPA/GRI study, reference the primary study is necessary to validate the factors.
Refining - combustion sources				
	Boilers		4.1, 4.2, 4.3	The Compendium methods for combustion are acceptable.
	Process heaters		4.1, 4.2, 4.3	
	Turbines		4.1, 4.2, 4.3	
	Engines		4.1, 4.2, 4.3	
	Flares		4.4	
	Catalytic and thermal oxidizers		4.6	
	Coke calcining kilns		4.6	
	Incinerators		4.6	
	Company vehicles		4.5	
	Electricity imports		4.7	

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Industry Sector and Source	Applicable Methods Listed In API Compendium	API Comp-endium Section	Remarks on technique, methodology, strengths, and weaknesses
Process heat/steam imports		4.7	
Refining - vented sources			
Catalytic cracking		5.2.1	The GHG emission estimating methods presented in the API Compendium for petroleum refineries are acceptable. In the absence of a definition of "insignificant," often referred to as a "de minimis" standard for GHG reporting, it is not possible to draw conclusions about Compendium statements that certain sources are "negligible." Another table identifies sources missing from the API Compendium, based on de minimis standards adopted by other oil companies.
Catalytic reforming		5.2.1	
Catalytic regeneration		5.21. 5.2.4	
Thermal cracking		5.2.6	
Flexi-coking		5.2.3	
Delayed coking		5.2.3	
Steam methane reforming (hydrogen plants)		5.2.2	
Sulfur recovery units		5.2.6	
Asphalt production		5.2.5	
Storage tanks		5.4	
Pneumatic devices		5.6.1	
Loading racks		5.5	
Equipment/process blowdowns		5.7.6	
Heater/boiler tube decoking		5.7.6	
Compressor starts		5.7.6	
Pressure relief valves (PRV)		5.7.6	
Emergency shutdown (ESD)		5.7.6	
Refining - fugitive sources			
Fuel gas system leaks	Facility-level average emission factors, sector-specific	6.1	Refining methane fugitives are described as "negligible." Refineries have extensive fuel gas systems, with large component counts exempt from LDAR programs because the VOC content is typically less than 10%. Depending on the definition of "negligible" or "de

Evaluation of API Compendium Applicability for the California Petroleum and Natural Gas Industries

Industry Sector and Source		Applicable Methods Listed In API Compendium	API Comp-endium Section	Remarks on technique, methodology, strengths, and weaknesses
		Equipment level average emission factors, sector specific	B.3	minimis" the methane emissions from refinery fuel gas systems may or may not be worth evaluating. Emission factors for components in gas service are readily available, and the methane content of refinery fuel gas is typically well known, between 20 and 50 per cent. The Compendium describes results of a published study finding refinery fuel gas fugitive emissions to represent about 0.11% of total refinery GHG inventory. A second study was not published in time for the February 2004 edition of the Compendium, but will likely be included in the next edition, showing fuel gas emissions representing 0.19% of total refinery GHG inventory.
	Other process equipment leaks	Facility-level average emission factors, sector-specific	6.1	
		Equipment level average emission factors, sector specific	B.3	
	Wastewater collection and treating	Engineering Calculation	6.2.1	
	Sludge/solids handling		6.2.1	
	Cooling towers		6.2.1	
Petrochemical manufacturing - combustion sources				Petrochemical Operations are not part of the natural gas and oil sector
Petrochemical manufacturing - vented sources				Petrochemical Operations are not part of the natural gas and oil sector
Petrochemical manufacturing - fugitive sources				Petrochemical Operations are not part of the natural gas and oil sector
Retail and Marketing - combustion sources				
	Thermal oxidizers		4.6	The Compendium methods for combustion are acceptable.
	Marine tankers		4.5	
	Road tankers		4.5	
	Railroad tankers		4.5	
	Other company vehicles		4.5	
	Electricity usage		4.7	
Retail and Marketing - vented sources				
	Service station storage tanks	Assume Negligible	5.4	Acceptable for petroleum products.

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Industry Sector and Source	Applicable Methods Listed In API Compendium	API Comp-endium Section	Remarks on technique, methodology, strengths, and weaknesses
Retail and Marketing - fugitive sources			
Process equipment leaks	Assume Negligible	6.1	Acceptable for petroleum products.
Electricity and Heat/Steam Generation - combustion			
Turbines		4.1, 4.2, 4.3	The Compendium methods for combustion are acceptable.
Boilers/Steam Generators		4.1, 4.2, 4.3	
Company vehicles		4.5	
Electricity and Heat/Steam Generation - vented			
Natural gas distribution process/equipment vents		5.7	This source may double-count refinery process vents.
Electricity and Heat/Steam Generation - fugitive			
Natural gas distribution equipment leaks	Equipment level average emission factors, sector specific	6.1	This source may double-count refinery fugitives.

Appendix B. MMS GOADS 2000 Data Analysis

Table 20. Deep Water Gas Platforms — Emissions Factors Estimates

DEEP WATER GAS PLATFORMS UNCERTAINTY ANALYSIS RESULTS - EMISSIONS FROM SOURCE						
Source	Number of Deep Water Gas Platforms with Source	Emissions for Platforms with Source (Mcf CH4/ Platform)	Lower Bound (95% CI)		Upper Bound (95% CI)	
			(Mcf CH4/ Platform)	% Deviation from Mean	(Mcf CH4/ Platform)	% Deviation from Mean
BOI<10 Natural Gas	5	3.24	0.66	80%	9.90	206%
BOI10-100 Natural Gas	1	5.49	3.80	31%	7.69	40%
DIE<600 Diesel	11	1.52	0.07	95%	7.70	408%
DIE>600 Diesel	5	4.58	0.24	95%	22.46	390%
DRI-diesel Diesel	5	16.43	1.44	91%	69.19	321%
FLA-LN-flaring natural gas	1	354.77	246.44	31%	498.69	41%
FLA-MP-flaring natural gas	1	239.71	165.71	31%	335.95	40%
FLA-MP-pilot natural gas	1	0.07	0.05	31%	0.10	40%
FLA-MP-ups-flaring natural gas	1	7.66	5.29	31%	10.75	40%
FLA-NP-flaring natural gas	1	162.21	112.36	31%	228.14	41%
FLA-NP-pilot natural gas	1	0.11	0.07	31%	0.15	40%
FLA-NP-ups-flaring natural gas	1	6,167.82	4,276.26	31%	8,599.05	39%
FUG-CENT-DRY Oil/Water	1	7.66	5.31	31%	10.78	41%
FUG-CENT-PACK Gas	1	15.28	10.58	31%	21.40	40%
FUG-CENT-PACK Light Oil (>=20 APIG)	1	59.10	24.69	58%	119.79	103%
FUG-CENT-PACK Oil/Water	4	38.67	11.19	71%	98.98	156%
FUG-CENT-WET Oil/Water	1	53.65	37.06	31%	75.21	40%
FUG-CON Gas	3	39.65	24.57	38%	60.70	53%
FUG-CON Light Oil (>=20 APIG)	2	51.78	6.29	88%	191.46	270%
FUG-CON Oil/Water	6	96.80	40.20	58%	196.96	103%
FUG-CON Oil/Water/Gas	1	2.27	1.56	31%	3.16	40%
FUG-FLANGE Gas	3	82.45	55.62	33%	116.61	41%
FUG-FLANGE Light Oil (>=20 APIG)	2	203.26	15.29	92%	943.00	364%
FUG-FLANGE Oil/Water	6	213.42	21.43	90%	845.50	296%
FUG-FLANGE Oil/Water/Gas	1	62.48	43.54	30%	87.84	41%
FUG-OTHER Gas	3	2,926.04	1,696.96	42%	4,697.31	61%
FUG-OTHER Light Oil (>=20 APIG)	2	3,075.12	517.96	83%	10,316.96	235%
FUG-OTHER Oil/Water	6	4,456.93	2,268.96	49%	7,795.80	75%
FUG-OTHER Oil/Water/Gas	1	734.78	511.75	30%	1,029.48	40%
FUG-OTHER-COMP Gas	1	7.64	5.26	31%	10.68	40%
FUG-PUMP Gas	3	15.83	1.09	93%	74.84	373%
FUG-PUMP Light Oil (>=20 APIG)	1	50.73	6.44	87%	188.02	271%
FUG-PUMP Oil/Water	6	27.34	3.21	88%	106.48	289%

DEEP WATER GAS PLATFORMS UNCERTAINTY ANALYSIS RESULTS - EMISSIONS FROM SOURCE						
Source	Number of Deep Water Gas Platforms with Source	Emissions for Platforms with Source (Mcf CH4/ Platform)	Lower Bound (95% CI)		Upper Bound (95% CI)	
			(Mcf CH4/ Platform)	% Deviation from Mean	(Mcf CH4/ Platform)	% Deviation from Mean
FUG-PUMP Oil/Water/Gas	1	5.48	3.82	30%	7.69	40%
FUG-VALVE Gas	3	215.24	146.82	32%	305.08	42%
FUG-VALVE Light Oil (>=20 APIG)	2	1,748.94	152.52	91%	7,400.71	323%
FUG-VALVE Oil/Water	6	2,423.43	502.36	79%	7,244.57	199%
FUG-VALVE Oil/Water/Gas	1	938.63	651.14	31%	1,308.35	39%
GLY-TEG natural gas	7	10,908.63	1,087.27	90%	46,558.81	327%
LOS-HT oil	2	11,682.30	5,172.71	56%	22,932.41	96%
LOS-Other oil	1	23,092.29	17,908.10	22%	29,616.31	28%
LOS-Sep oil	1	7,960.70	672.25	92%	,941.86	339%
LOS-Sto oil	1	3,095.51	2,382.60	23%	3,948.13	28%
LOS-Sur oil	1	18,505.13	14,290.82	23%	23,664.88	28%
MUD-wat gas	1	2,213.88	1,533.63	31%	3,107.17	40%
NGE-4L natural gas	2	936.11	76.34	92%	4,100.27	338%
NGE-4R natural gas	8	7,108.35	(2,900.83)	141%	16,880.13	137%
NGT natural gas	7	772.48	(537.07)	170%	2,212.23	186%
PNE-pump natural gas	2	2,667.34	(66.37)	102%	10,404.67	290%
PRE natural gas	2	347.76	44.05	87%	1,356.65	290%
STO-fixed Condensate	3	180.14	1.91	99%	1,129.53	527%
STO-fixed Crude	4	563.47	1.84	100%	4,070.79	622%
STO-float Condensate	1	12.31	9.43	23%	15.76	28%
VEN exhaust gas	4	10,725.23	(2,415.80)	123%	50,344.56	369%
	Total Number of Platforms	Total Emissions (Mcf)	Emissions/ Platform			
TOTAL DEEP WATER GAS PLATFORMS	12	342,948.17	0.029 Bcf			

Table 111.Deep Water Oil Platforms — Emissions Factors Estimates

DEEP WATER OIL PLATFORMS UNCERTAINTY ANALYSIS RESULTS - EMISSIONS FROM SOURCE						
Source	Number of Deep Water Oil Platforms with Source	Emissions for Platforms with Source (Mcf CH4/ Platform)	Lower Bound (95% CI)		Upper Bound (95% CI)	
			(Mcf CH4/ Platform)	% Deviation from Mean	(Mcf CH4/ Platform)	% Deviation from Mean
BOI<10 Natural Gas	5	0.98	0.07	93%	4.66	373%
DIE<600 Diesel	19	1.81	0.09	95%	9.15	407%
DIE>600 Diesel	17	3.53	0.09	98%	20.92	493%
DRI-diesel Diesel	11	9.82	1.49	85%	32.74	233%
DRI-gasoline gasoline	1	1,106.54	761.65	31%	1,540.95	39%
DRI-ng natural gas	1	539.95	369.95	31%	753.32	40%
FLA-LN-flaring natural gas	2	4,879.76	790.34	84%	15,979.35	227%
FLA-LP-flaring natural gas	1	1.54	1.06	31%	2.14	39%
FLA-LP-pilot natural gas	1	3.67	2.56	30%	5.16	41%
FLA-NN-flaring natural gas	3	5,168.86	603.08	88%	19,904.46	285%
FLA-NP-flaring natural gas	1	1,138.70	789.68	31%	1,601.67	41%
FLA-NP-pilot natural gas	1	0.36	0.25	30%	0.51	40%
FUG-CENT-DRY Gas	3	35,772.27	25,801.76	28%	48,393.57	35%
FUG-CENT-DRY Oil/Water/Gas	1	15.57	10.75	31%	21.67	39%
FUG-CENT-PACK Gas	4	57.48	7.43	87%	212.28	269%
FUG-CENT-PACK Light Oil (>=20 APIG)	2	44.41	14.35	68%	106.86	141%
FUG-CENT-PACK Oil/Water	5	49.75	17.43	65%	111.68	124%
FUG-CENT-WET Gas	1	84,375.97	58,234.51	31%	117,764.46	40%
FUG-CENT-WET Light Oil (>=20 APIG)	2	54.04	6.94	87%	198.16	267%
FUG-CENT-WET Oil/Water	1	15.30	10.61	31%	21.20	39%
FUG-CENT-WET Oil/Water/Gas	2	31.42	7.34	77%	90.31	187%
FUG-CON Gas	7	59.59	19.14	68%	145.93	145%
FUG-CON Light Oil (>=20 APIG)	4	132.95	50.37	62%	283.84	113%
FUG-CON Oil/Water	7	97.13	37.20	62%	210.83	117%
FUG-CON Oil/Water/Gas	3	57.68	18.33	68%	140.26	143%
FUG-FLANGE Gas	7	121.13	46.78	61%	256.65	112%
FUG-FLANGE Light Oil (>=20 APIG)	4	427.22	77.91	82%	1,352.98	217%
FUG-FLANGE Oil/Water	7	277.28	34.93	87%	1,048.81	278%
FUG-FLANGE Oil/Water/Gas	3	312.06	67.88	78%	925.31	197%
FUG-OTHER Gas	7	4,570.61	1,607.82	65%	12,376.65	171%
FUG-OTHER Light Oil (>=20 APIG)	4	5,926.52	2,845.10	52%	10,947.41	85%
FUG-OTHER Oil/Water	7	4,782.03	1,633.12	66%	9,475.96	98%
FUG-OTHER Oil/Water/Gas	3	2,859.81	1,178.53	59%	5,786.02	102%
FUG-OTHER-COMP Light Oil (>=20 APIG)	1	7.67	5.32	31%	10.67	39%
FUG-OTHER-COMP Oil/Water	1	40.86	17.00	58%	81.59	100%

DEEP WATER OIL PLATFORMS UNCERTAINTY ANALYSIS RESULTS - EMISSIONS FROM SOURCE						
Source	Number of Deep Water Oil Platforms with Source	Emissions for Platforms with Source (Mcf CH4/ Platform)	Lower Bound (95% CI)		Upper Bound (95% CI)	
			(Mcf CH4/ Platform)	% Deviation from Mean	(Mcf CH4/ Platform)	% Deviation from Mean
FUG-OTHER-COMP Oil/Water/Gas	1	46.70	32.42	31%	65.56	40%
FUG-PUMP Gas	7	34.59	6.22	82%	113.28	227%
FUG-PUMP Light Oil (>=20 APIG)	4	69.43	11.42	84%	229.74	231%
FUG-PUMP Oil/Water	7	60.52	7.62	87%	222.17	267%
FUG-PUMP Oil/Water/Gas	3	25.18	1.58	94%	117.21	365%
FUG-VALVE Gas	7	347.92	118.03	66%	811.96	133%
FUG-VALVE Light Oil (>=20 APIG)	4	3,742.47	861.85	77%	10,703.17	186%
FUG-VALVE Oil/Water	7	2,518.22	458.61	82%	8,039.85	219%
FUG-VALVE Oil/Water/Gas	3	2,196.85	527.61	76%	6,091.71	177%
GLY-TEG natural gas	5	3,533.69	469.71	87%	13,567.02	284%
LOS-HT oil	2	564,378.09	19,509.90	97%	3,211,259.68	469%
LOS-Sto oil	3	2,574.84	497.08	81%	7,901.06	207%
LOS-Sur oil	1	5,810.72	4,466.29	23%	7,426.97	28%
MUD-syn gas	5	470.96	99.33	79%	1,423.49	202%
MUD-wat gas	1	2,987.84	2,071.43	31%	4,185.56	40%
NGE-2L natural gas	1	40,902.62	31,388.00	23%	52,579.38	29%
NGE-2R natural gas	1	31,234.43	23,957.55	23%	40,150.17	29%
NGE-4C natural gas	2	2,886.62	853.14	70%	7,297.49	153%
NGE-4L natural gas	2	18,174.84	3,758.44	79%	55,134.98	203%
NGE-4R natural gas	9	11,862.27	1,166.06	90%	49,381.69	316%
NGT natural gas	17	1,810.12	200.54	89%	6,504.86	259%
PNE-pump natural gas	3	350.18	19.24	95%	1,714.78	390%
PRE natural gas	1	58.19	4.65	92%	257.61	343%
STO-fixed Condensate	2	692.08	24.69	96%	3,756.53	443%
STO-fixed Crude	16	3,041.26	(9,228.23)	403%	29,371.96	866%
VEN exhaust gas	15	16,601.41	(521.89)	103%	65,075.89	292%
	Total Number of Platforms	Total Emissions (Mcf)	Emissions /Platform			
TOTAL DEEP WATER OIL PLATFORMS	22	2,085,722.86	0.095 Bcf			

Table 122.Shallow Water Gas Platforms — Emissions Factors Estimates

SHALLOW WATER GAS PLATFORMS UNCERTAINTY ANALYSIS RESULTS - EMISSIONS FROM SOURCE						
Source	Number of Shallow Water Gas Platforms with Source	Emissions for Platforms with Source (Mcf CH4/ Platform)	Lower Bound (95% CI)		Upper Bound (95% CI)	
			(Mcf CH4/ Platform)	% Deviation from Mean	(Mcf CH4/ Platform)	% Deviation from Mean
FUG-CENT-DRY Gas	3	20,966.47	9,677.79	54%	39,363.18	88%
FUG-CENT-DRY Oil/Water	3	8.95	2.23	75%	24.29	171%
FUG-CENT-DRY Oil/Water/Gas	105	17.04	9.37	45%	28.03	65%
FUG-CENT-PACK Gas	66	23.11	4.26	82%	73.81	219%
FUG-CENT-PACK Light Oil (>=20 APIG)	50	24.59	3.17	87%	92.66	277%
FUG-CENT-PACK NGL	1	15.33	10.61	31%	21.52	40%
FUG-CENT-PACK Oil/Water	96	24.20	4.65	81%	77.20	219%
FUG-CENT-PACK Oil/Water/Gas	24	24.15	5.95	75%	67.02	177%
FUG-CENT-WET Gas	14	77,260.60	21,081.98	73%	202,739.59	162%
FUG-CENT-WET Light Oil (>=20 APIG)	6	5.81	1.15	80%	17.81	207%
FUG-CENT-WET Oil/Water	7	9.61	2.30	76%	26.66	177%
FUG-CENT-WET Oil/Water/Gas	164	22.05	6.70	70%	54.63	148%
FUG-CON Gas	390	13.39	1.34	90%	54.40	306%
FUG-CON Heavy Oil (<20 APIG)	5	20.63	1.69	92%	89.45	334%
FUG-CON Light Oil (>=20 APIG)	291	19.88	1.15	94%	95.80	382%
FUG-CON NGL	1	25.50	10.86	57%	51.06	100%
FUG-CON Oil/Water	538	18.22	1.20	93%	84.31	363%
FUG-CON Oil/Water/Gas	502	18.36	2.85	84%	63.29	245%
FUG-FLANGE Gas	384	31.98	2.40	92%	143.26	348%
FUG-FLANGE Heavy Oil (<20 APIG)	5	90.13	3.30	96%	497.41	452%
FUG-FLANGE Light Oil (>=20 APIG)	291	57.02	1.21	98%	341.74	499%
FUG-FLANGE NGL	1	81.63	13.15	84%	272.42	234%
FUG-FLANGE Oil/Water	538	60.03	1.44	98%	360.58	501%
FUG-FLANGE Oil/Water/Gas	500	74.72	14.05	81%	238.76	220%
FUG-OE Gas	7	14.50	0.36	97%	80.47	455%
FUG-OE Light Oil (>=20 APIG)	2	1.36	0.11	92%	5.90	332%
FUG-OE Oil/Water/Gas	11	1.47	0.30	80%	4.53	209%
FUG-OTHER Gas	396	945.88	34.88	96%	3,822.51	304%
FUG-OTHER Heavy Oil (<20 APIG)	5	1,409.15	121.90	91%	6,179.01	338%
FUG-OTHER Light Oil (>=20 APIG)	291	1,034.13	45.83	96%	4,253.78	311%
FUG-OTHER NGL	1	1,226.58	471.61	62%	2,611.46	113%
FUG-OTHER Oil/Water	538	1,006.56	26.75	97%	4,330.86	330%
FUG-OTHER Oil/Water/Gas	503	1,153.52	64.47	94%	4,169.52	261%
FUG-OTHER-COMP Gas	31	18.98	3.50	82%	60.79	220%
FUG-OTHER-COMP Heavy Oil (<20	5	11	1.32	88%	43.33	283%

SHALLOW WATER GAS PLATFORMS UNCERTAINTY ANALYSIS RESULTS - EMISSIONS FROM SOURCE						
Source	Number of Shallow Water Gas Platforms with Source	Emissions for Platforms with Source (Mcf CH4/ Platform)	Lower Bound (95% CI)		Upper Bound (95% CI)	
			(Mcf CH4/ Platform)	% Deviation from Mean	(Mcf CH4/ Platform)	% Deviation from Mean
APIG)						
FUG-OTHER-COMP Light Oil (>=20 APIG)	18	14.58	2.21	85%	48.63	233%
FUG-OTHER-COMP Oil/Water	39	15.57	2.52	84%	52.59	238%
FUG-OTHER-COMP Oil/Water/Gas	43	55.58	4.18	92%	249.00	348%
FUG-PUMP Gas	137	16.85	0.64	96%	93.05	452%
FUG-PUMP Heavy Oil (<20 APIG)	5	9.40	0.50	95%	46.72	397%
FUG-PUMP Light Oil (>=20 APIG)	121	19.71	1.02	95%	94.62	380%
FUG-PUMP NGL	1	29.22	20.25	31%	40.71	39%
FUG-PUMP Oil/Water	213	19.58	0.90	95%	101.08	416%
FUG-PUMP Oil/Water/Gas	191	5.65	0.56	90%	23.04	308%
FUG-VALVE Gas	396	84.32	9.53	89%	331.56	293%
FUG-VALVE Heavy Oil (<20 APIG)	5	767.68	32.08	96%	4,032.24	425%
FUG-VALVE Light Oil (>=20 APIG)	291	562.70	9.56	98%	3,212.80	471%
FUG-VALVE NGL	1	367.13	83.22	77%	1,082.52	195%
FUG-VALVE Oil/Water	538	531.46	8.23	98%	3,169.43	496%
FUG-VALVE Oil/Water/Gas	503	549.59	35.08	94%	2,055.63	274%
AMI natural gas	5	114.23	0.14	100%	794.08	595%
BOI Process Gas	21	0.50	0.06	87%	1.84	271%
BOI Waste Gas	1	0.32	0.22	31%	0.45	40%
BOI<10 Natural Gas	296	0.54	0.04	93%	2.47	358%
BOI>100 Natural Gas	4	0.49	0.07	86%	1.73	254%
BOI10-100 Natural Gas	7	6.79	1.31	81%	20.90	208%
DIE<600 Diesel	992	0.52	0.00	99%	3.33	542%
DIE>600 Diesel	75	0.78	0.01	99%	4.95	534%
DRI-diesel Diesel	153	3.27	0.23	93%	14.87	355%
DRI-gasoline gasoline	1	41.75	8.98	31%	58.24	40%
FLA-LN-flaring natural gas	1	1.61	1.11	31%	2.25	40%
FLA-LP-flaring natural gas	2	1,819.35	138.34	92%	8,048.95	342%
FLA-LP-pilot natural gas	2	0.46	0.14	71%	1.17	154%
FLA-LP-ups-flaring natural gas	1	1,031.02	718.19	30%	1,431.70	39%
FLA-NN-flaring natural gas	6	129.72	7.77	94%	615.53	375%
FLA-NP-flaring natural gas	9	185.11	14.27	92%	843.47	356%
FLA-NP-pilot natural gas	9	1.04	0.35	66%	2.37	127%
FLA-NP-ups-flaring natural gas	1	42.37	29.45	30%	59.51	40%
GLY-EG	1	61.36	42.56	31%	86.01	40%
GLY-TEG	121	3,342.91	41.54	99%	21,425.06	541%

SHALLOW WATER GAS PLATFORMS UNCERTAINTY ANALYSIS RESULTS - EMISSIONS FROM SOURCE						
Source	Number of Shallow Water Gas Platforms with Source	Emissions for Platforms with Source (Mcf CH4/ Platform)	Lower Bound (95% CI)		Upper Bound (95% CI)	
			(Mcf CH4/ Platform)	% Deviation from Mean	(Mcf CH4/ Platform)	% Deviation from Mean
LOA Oil	5	76.90	4.68	94%	383.28	398%
LOS-HT oil	15	22,631.88	(74,389.89)	429%	219,563.29	870%
LOS-Other oil	13	6,057.53	53.42	99%	39,796.85	557%
LOS-Sep oil	5	19,173.40	(1,033.90)	105%	154,440.77	705%
LOS-Sto oil	27	5,062.13	(1.59)	100%	34,228.65	576%
LOS-Sur oil	23	14,927.38	(10.15)	100%	101,202.37	578%
MUD-oil gas	8	188.85	30.95	84%	622.55	230%
MUD-syn gas	17	110.71	17.36	84%	368.24	233%
MUD-wat gas	60	564.50	98.56	83%	1,881.57	233%
NGE-2C natural gas	2	12,968.52	4,941.58	62%	28,065.39	116%
NGE-2L natural gas	14	5,935.38	964.86	84%	19,919.56	236%
NGE-2R natural gas	4	4,391.58	275.20	94%	21,554.35	391%
NGE-4C natural gas	78	3,411.99	338.98	90%	13,782.93	304%
NGE-4L natural gas	88	4,356.05	549.07	87%	16,142.91	271%
NGE-4R natural gas	504	4,674.50	104.50	98%	17,230.90	269%
NGT natural gas	68	440.31	48.62	89%	1,763.80	301%
PNE-inj natural gas	87	1,221.06	301.99	75%	3,440.55	182%
PNE-pump natural gas	618	679.86	0.92	100%	4,428.08	551%
PNE-sump natural gas	147	35.49	0.31	99%	239.94	576%
PRE natural gas	667	524.67	8.70	98%	2,601.09	396%
STO-fixed Condensate	74	157.04	0.00	100%	674.61	330%
STO-fixed Crude	138	673.93	0.04	100%	4,655.00	591%
VEN exhaust gas	264	9,803.73	211.21	98%	36,319.82	270%
	Total Number of Platforms	Total Emissions (Mcf)	Emissions/ Platform			
TOTAL SHALLOW WATER GAS PLATFORMS	1821	12,049,947.7	0.007 Bcf			

Table 133. Shallow Water Oil Platforms — Emissions Factors Estimate

SHALLOW WATER OIL PLATFORMS UNCERTAINTY ANALYSIS RESULTS - EMISSIONS FROM SOURCE						
Source	Number of Shallow Water Oil Platforms with Source	Emissions for Platforms with Source (Mcf CH4/ Platform)	Lower Bound (95% CI)		Upper Bound (95% CI)	
			(Mcf CH4/ Platform)	% Deviation from Mean	(Mcf CH4/ Platform)	% Deviation from Mean
FUG-CENT-DRY Oil/Water	2	65.36	19.39	70%	162.22	148%
FUG-CENT-DRY Oil/Water/Gas	26	26.35	2.54	90%	108.56	312%
FUG-CENT-PACK Gas	41	32.10	4.95	85%	112.99	252%
FUG-CENT-PACK Light Oil (>=20 APIG)	32	28.41	4.73	83%	94.01	231%
FUG-CENT-PACK Oil/Water	67	31.17	6.75	78%	93.45	200%
FUG-CENT-PACK Oil/Water/Gas	6	31.27	11.37	64%	69.67	123%
FUG-CENT-WET Gas	5	138,505.75	29,983.38	78%	406,848.50	194%
FUG-CENT-WET Light Oil (>=20 APIG)	8	19.80	3.49	82%	64.65	227%
FUG-CENT-WET Oil/Water	9	26.56	3.11	88%	102.58	286%
FUG-CENT-WET Oil/Water/Gas	43	30.27	4.21	86%	108.28	258%
FUG-CON Gas	198	19.63	2.19	89%	78.29	299%
FUG-CON Heavy Oil (<20 APIG)	2	13.48	0.40	97%	75.80	462%
FUG-CON Light Oil (>=20 APIG)	187	23.04	1.42	94%	109.60	376%
FUG-CON NGL	4	6.43	0.86	87%	23.70	269%
FUG-CON Oil/Water	356	25.27	1.23	95%	131.55	421%
FUG-CON Oil/Water/Gas	137	22.62	2.68	88%	86.29	281%
FUG-FLANGE Gas	198	48.04	6.54	86%	173.95	262%
FUG-FLANGE Heavy Oil (<20 APIG)	2	8.45	0.16	98%	52.50	521%
FUG-FLANGE Light Oil (>=20 APIG)	262	45.64	0.77	98%	293.30	543%
FUG-FLANGE NGL	4	11.45	1.82	84%	39.42	244%
FUG-FLANGE Oil/Water	357	74.78	1.37	98%	437.50	485%
FUG-FLANGE Oil/Water/Gas	139	93.40	11.97	87%	350.02	275%
FUG-OE Gas	3	19.88	2.77	86%	71.23	258%
FUG-OE Heavy Oil (<20 APIG)	2	6.62	0.54	92%	28.79	335%
FUG-OE Light Oil (>=20 APIG)	1	13.37	1.26	91%	56.97	326%
FUG-OE Oil/Water	6	19.56	0.86	96%	104.50	434%
FUG-OE Oil/Water/Gas	2	2.06	0.28	86%	7.80	278%
FUG-OTHER Gas	198	1,388.83	51.35	96%	5,913.04	326%
FUG-OTHER Heavy Oil (<20 APIG)	2	1,803.08	173.26	90%	7,573.15	320%
FUG-OTHER Light Oil (>=20 APIG)	262	870.15	27.17	97%	3,696.88	325%
FUG-OTHER NGL	4	350.72	49.85	86%	1,273.64	263%
FUG-OTHER Oil/Water	357	1,338.18	41.14	97%	5,611.14	319%
FUG-OTHER Oil/Water/Gas	139	1,317.74	167.51	87%	4,831.58	267%
FUG-OTHER-COMP Gas	18	22.62	3.51	84%	77.92	244%
FUG-OTHER-COMP Light Oil (>=20 APIG)	13	38.08	4.71	88%	148.48	290%
FUG-OTHER-COMP Oil/Water	32	19.02	3.48	82%	60.66	219%

SHALLOW WATER OIL PLATFORMS UNCERTAINTY ANALYSIS RESULTS - EMISSIONS FROM SOURCE						
Source	Number of Shallow Water Oil Platforms with Source	Emissions for Platforms with Source (Mcf CH4/ Platform)	Lower Bound (95% CI)		Upper Bound (95% CI)	
			(Mcf CH4/ Platform)	% Deviation from Mean	(Mcf CH4/ Platform)	% Deviation from Mean
FUG-OTHER-COMP Oil/Water/Gas	15	29.35	1.33	95%	150.19	412%
FUG-PUMP Gas	83	25.19	1.56	94%	115.07	357%
FUG-PUMP Light Oil (>=20 APIG)	63	23.81	1.60	93%	112.01	370%
FUG-PUMP Oil/Water	129	24.57	1.59	94%	113.87	364%
FUG-PUMP Oil/Water/Gas	78	10.03	0.33	97%	54.38	442%
FUG-VALVE Gas	198	130.95	18.50	86%	471.44	260%
FUG-VALVE Heavy Oil (<20 APIG)	2	81.06	1.41	98%	472.14	482%
FUG-VALVE Light Oil (>=20 APIG)	262	460.14	10.55	98%	2,654.82	477%
FUG-VALVE NGL	4	168.85	26.25	84%	581.30	244%
FUG-VALVE Oil/Water	357	661.76	7.27	99%	3,835.80	480%
FUG-VALVE Oil/Water/Gas	139	704.43	91.60	87%	2,588.84	268%
AMI natural gas	3	82.61	1.59	98%	494.03	498%
BOI Process Gas	8	0.43	0.08	82%	1.40	224%
BOI Waste Gas	2	0.11	0.01	88%	0.43	276%
BOI<10 Natural Gas	109	0.96	0.06	94%	4.47	366%
BOI>100 Natural Gas	4	794.70	29.52	96%	4,123.61	419%
BOI10-100 Natural Gas	8	7.03	1.87	73%	19.07	171%
DIE<600 Diesel	559	0.58	0.01	99%	3.47	497%
DIE>600 Diesel	33	1.53	0.02	99%	10.24	568%
DRI-diesel Diesel	121	4.51	0.32	93%	20.55	355%
DRI-ng natural gas	3	1,085.83	120.58	89%	4,152.69	282%
FLA-LN-flaring natural gas	1	148.47	102.20	31%	207.97	40%
FLA-LP-flaring natural gas	2	294.78	26.32	91%	1,261.97	328%
FLA-LP-pilot natural gas	2	1.22	0.33	73%	3.24	166%
FLA-LP-ups-flaring natural gas	1	511.88	354.07	31%	723.62	41%
FLA-MP-flaring natural gas	2	1,194.46	638.97	47%	2,053.75	72%
FLA-NN-flaring natural gas	7	141.97	6.66	95%	738.54	420%
FLA-NP-flaring natural gas	9	91.41	6.14	93%	418.16	357%
FLA-NP-pilot natural gas	9	0.64	0.05	92%	2.79	334%
GLY-EG natural gas	1	771.61	529.19	31%	1,084.40	41%
GLY-TEG natural gas	65	5,920.44	51.06	99%	37,046.04	526%
LOA Oil	3	50.46	23.28	54%	95.28	89%
LOS-HT oil	23	29,372.19	(6.95)	100%	173,580.87	491%
LOS-Other oil	5	5,091.26	168.03	97%	28,078.60	452%
LOS-Sep oil	1	10,020.41	6,966.74	30%	14,032.36	40%
LOS-Sto oil	25	24,096.38	(68.36)	100%	157,775.51	555%
LOS-Sur oil	7	22,423.59	0.76	100%	98,547.70	339%
MUD-oil gas	13	84.41	26.91	68%	203.78	141%

SHALLOW WATER OIL PLATFORMS UNCERTAINTY ANALYSIS RESULTS - EMISSIONS FROM SOURCE						
Source	Number of Shallow Water Oil Platforms with Source	Emissions for Platforms with Source (Mcf CH4/ Platform)	Lower Bound (95% CI)		Upper Bound (95% CI)	
			(Mcf CH4/ Platform)	% Deviation from Mean	(Mcf CH4/ Platform)	% Deviation from Mean
MUD-syn gas	16	129.77	14.81	89%	487.73	276%
MUD-wat gas	45	849.96	122.52	86%	3,002.45	253%
NGE-2C natural gas	4	8,503.62	4,946.97	42%	13,739.53	62%
NGE-2L natural gas	14	7,494.78	1,480.12	80%	22,825.16	205%
NGE-2R natural gas	18	9,536.33	2,280.23	76%	26,706.29	180%
NGE-4C natural gas	33	4,064.05	644.89	84%	13,927.30	243%
NGE-4L natural gas	37	6,593.13	1,233.81	81%	21,221.83	222%
NGE-4R natural gas	280	5,558.08	731.72	87%	20,649.37	272%
NGT natural gas	67	440.49	58.48	87%	1,561.50	254%
PNE-inj natural gas	48	1,002.68	147.90	85%	3,628.58	262%
PNE-pump natural gas	279	587.42	19.66	97%	3,190.97	443%
PNE-sump natural gas	63	93.83	3.96	96%	467.60	398%
PRE natural gas	320	643.86	22.61	96%	3,442.25	435%
STO-fixed Condensate	23	536.56	0.78	100%	4,195.06	682%
STO-fixed Crude	136	1,403.08	106.06	92%	5,933.59	323%
VEN exhaust gas	151	83,695.47	1,572.91	98%	311,072.65	272%
	Total Number of Platforms	Total Emissions (Mcf)	Emissions / Platform			
TOTAL SHALLOW WATER OIL PLATFORMS	1020	19,891,549	0.020 Bcf			