Sectoral Guidance for Consistent and Accurate Greenhouse Gas Emission Assessments

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ABSTRACT

With the increased focus on greenhouse gas emissions and diverse policy measures for their mitigation, there continues to be a growing need for accurate, reliable and transparent characterization of these emissions. A myriad of mandatory reporting regulations and voluntary initiatives are emerging in the U.S. and globally with diverse protocols and methodologies. This poses a particular challenge to multinational companies, such as in the Oil & Natural Gas industry sector, which operate globally and in joint ventures with different peer companies. The American Petroleum Institute and its member companies recognized this challenge over a decade ago and responded through a multi-year initiative to develop guidance documents and tools that promote consistent and accurate emission quantification and reporting of greenhouse gas emissions, and emission reduction projects.

This paper discusses the range of recent activities being undertaken by the industry sector to update its existing methodology compilation and provide new guidelines on emerging issues. The discussion will focus on the recent revision of the methodology compendium; the proposed framework for quantification of emission reduction projects; and technical considerations for addressing key sources of errors that have the largest impacts on the uncertainty of emission assessments. In addition to an overview of these industry documents, the paper emphasizes their application to operations beyond the oil and natural gas industry, i.e., industry sectors that rely on fossil fuels for their energy sources.

INTRODUCTION

The challenge of balancing energy supplies to meet growing global demands, while concurrently considering associated environmental impacts, is leading to an ever-increasing focus on greenhouse gas (GHG) emissions and their potential mitigation. Over the past few years a range of organizations and governmental agencies have published protocols and sectoral guidance for quantifying GHG emissions associated with voluntary reporting initiatives[1,2,3,4.] Oil and natural gas industry experts have participated as drafting and advisory committee members for many, if not all, of these reporting protocols. They have contributed to the development of global standards[5] and to emission inventory guidance for national GHG inventories[6]. The industry is also engaged and participates in consultations on mandatory GHG reporting regulations such as in the European Union emissions trading system (EU-ETS)[7], in the province of Alberta, Canada[8], and in California[9].

Currently, the number of states and regions across North America, including the U.S federal government, adopting policies to require reporting of GHG emissions is increasing at a fast pace. In most of these initiatives the essential first steps include developing 'top-down' statewide emission inventories as a baseline for action, followed by rules for 'bottoms-up' facility and entity reporting, in addition to emissions reductions tracking. With these emerging programs there is an increased emphasis on the confidence of data reported as a precursor to the development of mitigation policies.

The American Petroleum Institute (API) and its member companies recognized this challenge a decade ago and launched a multi-year initiative to map out and quantify GHG emissions from industry operations and similar industrial sources. During this decade-long initiative the industry developed several key guidance documents and tools to promote the consistent and accurate quantification and reporting of GHG emissions from oil and natural gas industry operations. It has also developed a framework for assessing GHG emission reductions that are attributable to specific projects. The objectives of these publicly available documents is to provide:

1) A compilation of applicable GHG estimation methodologies (API Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil & Gas Industry[10]);
2) Technical consideration and calculation methods for addressing the Uncertainty of GHG inventories (Uncertainty Document[11]); and
3) A series of guidelines to assist the oil and natural gas industry in identifying, assessing, and developing candidate projects that would lead to credible emission reductions (GHG Project Guidelines[12]).

API has previously reported on the initial phases of their initiative to develop methods and tools for consistent GHG emissions reporting[13], though this paper will focus only on new information that is pertinent to the documents listed above. This paper aims to provide highlights of the respective documents and to emphasize how they might apply to operations that are beyond the oil and natural gas industry. Indeed, many of the estimation methods and the recommended framework for assessing GHG emission reductions would apply broadly to those industry sectors that rely on fossil fuels for their energy sources.

OIL & NATURAL GAS INDUSTRY GHG INVENTORIES

Understanding the magnitude and sources of GHG emissions is a critical first step to managing them. Reliable GHG emission inventories developed in a consistent manner are fundamental for all GHG management schemes. For a large corporation with many divisions, facilities and operations, the key questions are:

- Which company facilities and emission sources are to be included?

- How will the inventory account, if at all, for indirect emissions from operations outside the company's facilities but created in support of its operations?
- What methods are available to estimate GHG emissions from a wide variety of sources?

The guidance provided by the industry includes reliable, efficient and cost-effective industry-endorsed methods for estimating and reporting GHG emissions. Although the guidance was originally developed by the oil and natural gas industry for their operations, many of the recommended methodologies have broader applicability and could serve as useful guidance for numerous other industrial applications.

Establishing an emissions inventory

At the most basic level, a GHG inventory is comprised of calculated and estimated emissions from individual emission sources. Emissions information is typically obtained either through direct on-site measurement of emissions, or the combination of an emission factor and some measure of the activity that results in the emission (referred to as the activity factor). Emissions from multiple sources are then aggregated to produce the inventory. Emission factors describe the emission rate associated with a given emission source, and they may be either based on site-specific measurements or published data. Activity factors are generally a measured quantity, such as a count of equipment or measure of fuel consumed.

One of the major challenges for complex GHG emission inventories, such as those for oil and natural gas companies, is the identification of the specific emission sources associated with each facility and the appropriate methods for estimating these emissions. GHG emission sources can be classified into three major categories:

1) **Combustion -** includes both stationary sources, portable devices as well as on-road and off-road transportation systems;
2) **Vented –** includes both normal venting from processing, storage, and product loading or off-loading as well as emergency releases; and
3) **Fugitive –** includes unintentional leakages from piping components and seals as well as wastewater and other waste handling systems.

Quantification of GHG emissions from each of the sources within those categories can be complicated by the variability of site operations and the availability of information about the quantity and quality of the fuels consumed. An additional complication in many processing and manufacturing facilities is that some of the fuels combusted are self-generated during the manufacturing process, are then rerouted back into the combustion devices that are used to run the facilities. Such fuels are typically variable in composition and cannot simply be characterized by published emission factors.

Understanding Data Uncertainty

Data quality and the uncertainty associated with it, plays a major role in all reporting programs and received prominence in the implementation of the EU-ETS, The uncertainty intervals associated with emission rates, activity data or emission factors are characterized by the dispersion of the respective measurements values that were used to derive them initially. Therefore assessing uncertainties of emission inventories is based on the characteristics of the variable(s) of interest (input quantity) as estimated from the applicable data sets or from expert judgments.

The overall uncertainty associated with an entity GHG inventory is usually determined primarily by the uncertainty associated with the largest ("key") sources of emissions. Although very high levels of uncertainty may be associated with some small sources, their overall impact on the uncertainty of a facility or entity-wide emissions may often be very small.

Assessing GHG Reductions from Projects

Although the requirements for creditable emission reductions continue to evolve, the technical concepts associated with quantifying GHG emission reductions are grounded in the basic principles of completeness, consistency, accuracy, relevance, transparency, and conservatism. Determination of emission reductions should be based on generally accepted principles and sound technical considerations.

Key elements of a credible GHG emission reduction framework include:

- Reported information should provide a faithful, true, and fair account of the reductions achieved;
- For existing operations, historical activity levels and operating practices, rather than historical emissions, often provide the most realistic baseline scenario;
- For new operations, common practice is generally an objective and credible prediction of what would have happened in the absence of the project; and
- Methods used for estimating and monitoring project reductions should be fit for their purpose.

API METHODOLOGY COMPENDIUM

The API developed the *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* (referred to as the Compendium). The Compendium, which represents the oil and natural gas industry's best practices for estimating GHG emissions, aims to accomplish the following goals[14]:

- Assemble an expansive collection of relevant emission factors and methodologies for estimating GHG emissions, based on currently available public documents;
- Outline detailed procedures for conversions between different measurement unit systems, with particular emphasis on implementation of oil and natural gas industry standards;
- Provide descriptions of the multitude of oil and natural gas industry operations—in its various segments—and the associated GHG emissions sources that should be considered; and
- Develop emission inventory examples—based on selected facilities from various oil and natural gas industry operations—to demonstrate the broad applicability of the methodologies.

From its original release in 2001, the overall objective in developing the Compendium is to promote the use of consistent, standardized methodologies for estimating GHG emissions from oil and natural gas industry operations. As a result, the Compendium document provides calculation techniques and emission factors for estimating GHG emissions for oil and natural gas industry operations, but also with broad applicability to any operations utilizing fossil fuels.

The third version of the Compendium will be released in mid-2009. It presents and illustrates the use of emission estimation methods for carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) for all common oil and natural gas industry emission sources, including combustion, vented, and fugitive. Table 1 presents a high level outline of the main sections and appendices of the API Compendium.

Table 1. Main Sections and Appendices of the API Compendium

Section	Title
	PREFACE
1.0	INTRODUCTION
2.0	INDUSTRY DESCRIPTION
3.0	TECHNICAL CONSIDERATIONS
4.0	COMBUSTION EMISSIONS ESTIMATION METHODS
5.0	PROCESS AND VENTED EMISSIONS ESTIMATION METHODS
6.0	FUGITIVE EMISSION ESTIMATION METHODS
7.0	INDIRECT EMISSIONS ESTIMATION METHODS
8.0	EMISSION INVENTORY EXAMPLES
APPENDICES	
A	ADDITIONAL COMBUSTION CALCULATION INFORMATION
B	ADDITIONAL VENTING CALCULATION INFORMATION
C	ADDITIONAL FUGITIVE CALCULATION INFORMATION
D	ADDITIONAL INDIRECT CALCULATION INFORMATION
E	ADDITIONAL INFORMATION
F	REFINERY METHANE FUGITIVE EMISSIONS STUDY
G	NITROUS OXIDE EMISSIONS STUDY

As more information related to GHG emission attributable to indirect emission sources becomes available, the API Compendium now features a separate section (Section 7.0) for this topic. In the previous version this discussion was included in the section on combustion emissions. Other key revisions to the 2009 version of the API Compendium include:

- Updated decision trees to guide the user in selecting an estimation technique based on considerations of materiality, data availability, and accuracy;
- Updated emission factors to reflect changes in referenced documents;
- Expanded discussion around emission estimation approaches for sources such as: dehydration operations, acid gas removal, tank flashing, pneumatic devices, hydrogen plants, catalytic cracking units, asphalt blowing, and wastewater treatment;
- Discussion on differences between crude oil from production operations and “weathered” crude, as well as limited GHG emissions from refined products;
- Updated case studies to include additional emission sources and operations;
- Revised discussion on inventory uncertainty to reflect the development of the Uncertainty Document; and
- Updated referenced uncertainty values to 95% confidence interval where data were available to make this revision.

In order to demonstrate the application of the Compendium GHG emission estimation methodologies, we will summarize briefly in the case study below the compilation of an inventory for a hypothetical petroleum refinery.

Case Study: GHG Inventory of a Hypothetical Petroleum Refinery

The case study applies to a complex fuels refinery that includes a hydrogen plant and a catalytic cracking unit. The Compendium provides the step-by-step emission calculations for the example refinery GHG emissions, focusing on emissions of CO_2, CH_4 and N_2O, as the relevant GHGs for such a facility. A brief overview is provided here, with a summary of resulting total direct facility emissions. Some key operating parameters for the hypothetical refinery studies are included in Exhibit 1.

Combustion emissions

Combustion related CO_2 emissions are calculated using the fuel composition and consumption rate, assuming all of the fuel carbon is converted to CO_2 during combustion. The carbon contents of the different streams are determined based on the compositions assigned for the example. Methane and N_2O emissions from combustion sources are determined by applying fuel and equipment specific emission factors.

Flaring and incinerator emissions are calculated similar to stationary combustion devices, with CO_2 emissions based on the quantity of gas flared, its composition, and assuming 98% combustion efficiency. Methane emissions for flares are calculated using an emission factor that is based on refinery throughput, i.e. the barrels of crude feed processed by the refinery. There is limited information on N_2O emissions from refinery flares. For incinerators, heater/boiler emission factors are used for CH_4 and N_2O emissions, with simplified assumptions about the incinerator gas stream.

For portable off-road equipment or essential mobile sources, CO_2 emissions are estimated based on fuel consumption, with CH_4 and N_2O emissions being determined by applying emission factors for the types of equipment or vehicles specified.

Exhibit 1
Parameters for Hypothetical Refinery

Throughput: Rated capacity of 250,000 bbl crude/day,

Combustion Fuel:

- Combustion sources are fired with either refinery fuel gas or natural gas.
- Refinery fuel gas has a heating value of 1,119 Btu/scf; the natural gas has a heating value of 1,050 Btu/scf,
- The refinery fuel gas feed rate is 4,000 million-scf/yr; the natural gas feed rate is 6,600 million-scf/yr.

Flaring:

- The flare gas has an average molecular weight of 72 lb/lb-mole
- The heating value of gas flared is 4,009 Btu/scf;
- The carbon content of the flared gas is assumed to be 83.24wt % carbon. (mainly pentanes)

Vented Emissions

The key sources of vented emissions in the example refinery are the hydrogen plant and the fluid catalytic cracker unit (FCCU) regenerator. Both processes result in CO_2 emissions. Refinery processes do not emit CH_4 since there is no CH_4 either in weathered crude (i.e., crude oil that has reached atmospheric pressure) or in refined petroleum products.

For the Hydrogen Plant, CO_2 emissions are calculated based on the feed rate and compositions of the feed streams. The Hydrogen plant uses both natural gas and refinery fuel gas as feed. For the FCCU, the Compendium provides three approaches for calculating CO_2 emissions (See Compendium equations 5-4, 5-5, and 5-6). Each of these approaches will require slightly different data for quantification, and might result with slightly differing values for CO_2 emissions. We will revisit this refinery example in the section below where we discuss the issue of addressing the uncertainty of GHG emission inventories. The full discussion on the issue is available in the Uncertainty Document, but we will highlight briefly below the impact of varying the FCCU calculation methods on the calculated CO_2 emissions and the uncertainty interval for this specific source.

Fugitive Emissions

Fugitive emissions from the refinery may include leaks associated with equipment handling natural gas or refinery fuel gas, refrigerant leaks, and leaks from transformers. The non-fuel gas system components handle liquids such as refined petroleum products, which do not contain CH_4 or CO_2. Therefore, there are no CH_4 or CO_2 emissions from non-fuel gas system components. Methane emission factors for fugitive leaks from refinery fuel gas and natural gas system components are estimated by applying an emission factor based on refinery throughput.

Facility Total Direct Emission

Facility total direct emissions for this case study are summarized in Table 2. The results show that 99.5% of the total CO2-E emitted by this example facility is CO_2, and almost 75% of it comes from combustion sources with about 25% from process vents, and 0.004% from fugitive emissions. The remainder 0.5% of total direct emissions comes from CH_4 and N_2O.

Table 2. Summary of Total Direct Annual Refinery Emissions

SOURCE CATEGORY	EMISSIONS (Tonnes/yr)			
	CO_2	CH_4	N_2O	CO_2-E [1]
Combustion Sources	2,958,115	482	12	2,971,957
Vented Sources	1,010,263	N/A	N/A	1,010,453
Fugitive Sources	161	221	N/A	4,802
TOTAL Direct Emissions	**3,968,538**	**703**	**12**	**3,987,022**

Note: [1] CO_2-E sum uses the following GWPs: CH_4 = 21; N_2O = 310;

ADDRESSING UNCERTAINTY IN OIL & NATURAL GAS INVENTORIES

Uncertainties associated with GHG emission inventories are the result of three main causes: (a) incomplete, unclear or faulty definitions of emission sources; (b) natural variability of the process that produces the emissions; and (c) improper models, or equations, used to quantify emissions for the process or quantity under considerations. When assessing the process or quantity under consideration, uncertainties could be attributable to one or more factors such as: sampling, measuring, incomplete reference data, or inconclusive expert judgment. The uncertainty associated with total annual emissions is comprised of several components of uncertainty, of which measurement uncertainty is but one. To the extent that measurement and accounting errors can be minimized, such action will have a direct influence on reducing the overall uncertainty associated with emission inventories.

The goal of conducting a detailed uncertainty assessment can be typically viewed as two fold:

1) Obtaining a quantitative assessment of the confidence intervals for the emissions calculated; and
2) Gaining insight into areas of high uncertainty where targeted data collection efforts could lead to material improvement of the emission inventory.

Quantifying the uncertainty for a GHG inventory involves mathematically combining individual sources of uncertainty to establish an estimate of the overall uncertainty. The general steps for quantifying uncertainty are:

- Determine the uncertainty for measured activity or emissions data;
- Evaluate the uncertainty of available emission factors data; and
- Aggregate uncertainty of individual components using standard statistical techniques.

As discussed above, the Compendium and its forthcoming 2009 revision (reference 13) provide an extensive compilation and tabulation of methods that are used by companies in all the sectors of the oil and natural gas industry to calculate their greenhouse gas (GHG) emissions in a consistent manner. The soon to be published companion document, *"Addressing Uncertainty for oil and natural gas industry GHG Inventories: Technical Considerations and Calculation Methods"* (Uncertainty Document) provides the needed background information and provides details on the statistical calculation methods that are relevant for the industry, but could be used by other sectors as part of their GHG inventory development. Table 3 provides the outline of the Uncertainty Document.

Table 3. Main Sections and Appendices of the Uncertainty Document

SECTION	TITLE
	FOREWORD
	DOCUMENT AT-A-GLANCE
1.0	INTRODUCTION
2.0	SOURCES OF UNCERTAINTY
3.0	OVERVIEW OF MEASUREMENT PRACTICES
4.0	STATISTICAL CALCULATION METHODS
5.0	CALCULATION EXAMPLES
6.0	REFERENCES
APPENDICES	
A	GLOSSARY OF STATISTICAL AND GHG INVENTORY TERMS
B	FLOW METERS INSPECTION & MAINTENACE
C	MEASUREMENT METHODS SUMMARIES
D	UNITS CONVESTION
E	UNCERTAINTY ESTIMATION DETAILS FOR AN EXAMPLE INVENTORY

Oil and natural gas industry operations extend over large geographical areas and encompass many jurisdictions, which make it hard to collect all the equipment counts and their associated activity data that are needed for compiling an emission inventory. Data availability may also exhibit regional variability that reflects the sector's operational considerations and local requirements. For example, the uncertainty associated with combustion emissions is primarily attributable to variation in fuel gas composition and its consumption rates (or total volume). While quality data is often available for large installations, significant effort may be required to obtain data for smaller facilities in multiple locations.

Those sectors of the Industry that engage in gas processing and refining rely heavily on self-generated fuels whose composition may vary with the nature of the producing formations, the composition of crude oil and/or gas used, and the slate of products manufactured. In exploration and production operations, gas compositions may not exhibit high variability for a given location but may vary among producing formations. Similarly, in pipeline transmission and distribution operations, gas quality and composition are expected to adhere to local requirements and would vary only within a narrow specifications range. Hence, while using average compositions for inventories might result in wide uncertainty ranges for some operations, they might be perfectly acceptable for others.

The Uncertainty document provides a detailed discussion on the statistical methods used to evaluate uncertainties and aggregate them. It also includes several examples on the potential application of such calculations for typical data collected by the oil and natural gas industry for assembling an emission inventory. In the case study that follows we demonstrate the use of derived uncertainty ranges for understanding the impact of the confidence intervals of the emissions from different source categories on the total GHG inventory.

Case Study: Impact of Fugitive Emission Uncertainty on Refinery Emissions

This example is based on the refinery example above with direct GHG emissions as summarized in Table 2. The data indicate that fugitive emissions of CO_2 contribute a negligible 0.004% to total refinery CO_2 emissions, while CH_4 fugitive emission represents about 31% of the refinery CH_4 emissions. Examining total fugitive emissions – GWP weighted sum of CO_2 and CH_4 emissions - we note that it amounts to about 0.12% of total CO_2-E for the facility studied.

In the revised API Compendium (API, 2009) all the case study examples in Section 8.0 now feature information about the uncertainty ranges for the respective emission sources. These calculations use the methods described in the Uncertainty Document and are based either on documented uncertainties, or applicable expert judgments. The uncertainties for individual sources are then aggregated to the facility level for a given category of sources. The data provided in the API Compendium for the refinery example indicates an aggregated uncertainty interval as large as $\pm$ 200% for fugitive emissions quantification.

We conducted a sensitivity analysis to assess the impact of such a wide confidence interval on the resultant GHG emissions calculated. For this analysis we've assumed that the fugitive emissions are represented by the upper range of the uncertainty interval, at +200% from the mean, which results in practice in tripling the estimated fugitive CO_2 and CH_4 emissions individually.

The immediate impact of using this upper level value for fugitive emissions will be an increased contribution of fugitive CH_4, rising from 31% to 57% of total refinery CH_4 emission. However, when analyzing the sensitivity of this change to total refinery CO_2-E emissions, we note that fugitive emissions contribution have increased merely from 0.12% to 0.36%, and total direct CO_2-E calculated has increased by an insignificant 0.24%.

GUIDANCE FOR EMISSION REDUCTION PROJECTS

Once a GHG inventory is established, a common next step is to examine opportunities for reducing GHG emissions. Countries, companies and other organizations worldwide are evaluating options for reducing greenhouse gas (GHG) emissions, developing project plans, and implementing emission reduction projects either voluntarily or to comply with regulatory requirements.

In 2007, API and the International Petroleum Industry Environmental Conservation Association (IPIECA) published the "Petroleum Industry Guidelines for Greenhouse Gas Emission Reduction Projects"[5] (referred to as the Project Guidelines), building on existing inventory guidance tools, but more specifically aimed toward providing technical guidance on GHG emission reduction projects. A high level outline of the sections and appendices of the Project Guidelines is provided in Table 4.

API and IPIECA also published Part II of the GHG emission reduction projects titled "Carbon Capture and Geological Storage Emission Reduction Family"[15]. This series of guidelines will be augmented by the industry with additional volumes providing technical guidance for calculating GHG emission reductions for other project families such as flaring reduction. However, for this paper the discussion will focus on the general principles provided in the first document in the series. The objectives of Project Guidelines document are:

- To develop a framework for assessing emission reductions associated with specific types of oil and gas GHG emission reduction projects, including references to relevant methodologies or guidance.
- To assist the oil and gas industry by providing guidelines on identifying, assessing, and developing candidate projects that would lead to credible (distinguished from creditable) GHG emission reductions.
- To remain policy and regime neutral in the discussion of credible emission reductions.

The purpose of the Project Guidelines is to provide oil and natural gas companies with a framework for evaluating, quantifying, documenting, and reporting GHG emission reduction projects. The Project Guidelines are written from the perspective of the oil and natural gas industry, with examples and considerations specific to its operations. Project types reviewed to date include cogeneration and carbon capture and geologic storage. Guidance addressing flare reduction is currently in development.

The focus of the Project Guidelines is on the technical considerations of emission reduction projects, recognizing that individual or public policy decisions may have a significant impact on the application of these technical principles. The Project Guidelines emphasize that:

- Determination of emission reductions should be based on generally accepted principles and sound technical considerations
- Care must be taken in selecting the baseline scenario in the petroleum industry
- Common practice or benchmarks can provide useful baselines but site specific issues mean that they can be difficult to apply to oil industry projects
- Policy decisions can significantly effect quantification and eligibility of reductions
- Baseline scenarios based on financial analysis are not always objective; and
- Excessive monitoring requirements may discourage participation without adding value

Table 4. Main Sections and Appendices of the Project Guidelines

SECTION	TITLE
	EXECUTIVE SUMMARY
1	INTRODUCTION
2	GHG REDUCTION PROJECT CONCEPTS AND PRINCIPLES
3	POLICY CONSIDERATIONS
4	OVERVIEW OF GHG REDUCTION PROJECT FAMILIES
5	COGENERATION PROJECT FAMILY
	REFERENCES
	GLOSSARY
APPENDICES	
A-1	SUMMARY OF GHG PROJECT-BASED EMISSION REDUCTION REGISTRIES
A-2	SUMMARY OF GHG PROJECT-BASED EMISSION REDUCTION INVENTORIES
B-1	COGENERATION PROJECT CASE STUDIES
B-2	BASELINE METHODOLOGIES FOR GRID-DISPLACEMENT REDUCTION PROJECTS

The Project Guidelines reiterate universally applicable quantification and reporting principles for credible GHG emission reduction quantification, as noted above. This will ensure that the reported information represents a faithful, true, and fair account of the GHG emission reductions achieved by implementing the reduction project; and the reported information is credible and unbiased in its treatment and presentation of issues. These principles become especially important where a GHG program is not available or has not clearly defined the processes and methodologies required for GHG project accounting and quantification.

The example below is a summary of the complete case study provided in the Project Guidelines, and is provided to demonstrate how to estimate the GHG emission reductions for a specific family of projects, i.e. installation of Combined Heat and Power (CHP) systems – also known as cogeneration. The oil and natural gas industry uses cogeneration systems to provide an efficient means of generating steam and electricity needed for refinery operations or for steam-flood in enhanced oil recovery operations. Specific issues and challenges related to quantifying GHG emission reductions associated with such projects are highlighted through the case study below.

Case Study: Combined Heat and Power Projects

This type of project has the potential to reduce GHG emissions in two ways:

1) The CHP system represents an improvement in overall energy efficiency compared to the separate generation of electricity and steam; and

2) The fuel source used may replace or displace more carbon intensive fuel sources, as compared with existing steam or electricity generation, or both.

The common configurations of a cogeneration system are either (a) a boiler that is used to make high-pressure steam that is fed to a turbine to produce electricity. The turbine is designed so that a stream of low-pressure steam is available to feed an industrial process; or (b) a combustion turbine or reciprocating engine is used to drive an electric generator, where the thermal energy is recovered from the exhaust stream to make steam or supply thermal energy.

The boiler/turbine CHP approach has been the most widely used CHP system to date, where one fuel input to the boiler is converted into both electric and thermal energy by extracting uncondensed steam from the turbine driving the electric generator. When evaluating GHG emission reductions from these types of projects key considerations would include: changes in direct emissions; thermal energy and electricity

Exhibit 2
CHP Case Study Parameters

Case 1: New Cogeneration Unit

– Consumes 15.57 PJ (14,760,000 MMBTU) of natural gas, producing 5.483 PJ (1,523,000 MW-hr) of electricity annually.
– The cogeneration facility also consumes 138.6 TJ (38,500 MW-hr) of electricity, referred to as the parasitic load.
– The facility uses 900 TJ (250,000 MW-hr) of electricity and the remainder is sold to the grid (4444.2 TJ).
– The project generates 1.32 PJ/yr (1,250,000 MMBtu/yr) of steam by the cogeneration unit for refinery use, thus decommissioning some coal-fired spreader stoker boilers.

Case 2: Increased on-site energy consumption

– Consumes 8.58 PJ (8,131,500 MMBtu) of natural gas, producing 3.96 PJ (1,100,600 MW-hr) of electricity annually.
– Before the project the facility consumed 712 TJ (198,000 MW-hr) of electricity, while after the project is increased to 990 TJ (275,000 MW-hr)
– The facility sells to the grid 2.83PJJ (768,100 MW-hr) of electricity
– The project enables increase of steam capacity for the refinery from 2.86xPJ (2,710,000 MMBtu) in the baseline to 3.81PJ (3,614,000 MMBtu/yr).

demands; current indirect energy imports; and potential for energy exports after the project. Exhibit 2 provides key operating parameters for the two options studied for a cogeneration installation.

Baseline Considerations

The baseline scenarios analyzed should represent plausible situations or conditions that would have occurred in the absence of the GHG reduction project. Separate considerations are needed for each of the two energy streams. One of the goals of a CHP project is the replacement of grid-connected electricity imports. This is not an easy task since electricity grids are typically based on different generation methods, each with their associated GHG emissions. The inherent complexity of the grid - and frequent changes in the generation mix - can make it difficult to determine exactly what source(s) will be displaced by a new grid-connected electricity project. Hence, the baseline scenario will change with time and should be re-evaluated periodically as appropriate.

Common baseline candidates for steam generation include on- or off-site steam production in less efficient steam boilers. In addition to the efficiency improvement for steam generation in a cogeneration unit, the steam generation portion of the GHG reduction project may also represent a fuel switch over from baseline scenario to a less carbon intensive fuel.

CHP Projects Characteristics

Emission reductions are defined as the difference between baseline emissions and GHG reduction project emissions for a given time period, typically on a recurring annual basis. Where the cogeneration project replaces previously imported electricity and/or steam, an increase in direct emissions due to onsite fuel combustion results. However, quantifying the emission reductions must consider the net change in GHG emissions from the imported energy streams in the baseline scenario relative to the emission sources created by the project. Direct emissions for a cogeneration project consist primarily of CO_2 emissions resulting from associated fuel combustion. The guidance provided by the API Compendium is used to quantify the GHG emissions, based on the quantity of fuel consumed and its carbon content. Fuel combustion also produces CH_4 and N_2O emissions – to a much lesser extent. Non-combustion CH4 emissions would also need to be considered due to potential venting and fugitive equipment leakages from sources associated with the natural gas supply to the cogeneration equipment.

CHP projects might be implemented under many permutations, as applicable to the host site. The example below is based on two potential cogeneration projects (see Exhibit 3 for details. These types of projects include:

1) **New Cogeneration Unit To Replace Steam Generation From An Offsite Steam Boiler –** where a facility constructs a CHP system that consists of: three natural gas fired combustion turbines; three heat recovery steam generators; supplemental duct firing capability; and three steam turbines.
2) **Cogeneration with Increased On-Site Energy Consumption –** where a facility installs a CHP system to improve its overall efficiency. Previously imported energy is replaced with on-site generation and excess electricity is exported to grid. Post-project energy use is higher than the baseline scenario due to organic growth.

GHG Emission Reduction Calculations

The two projects considered are similar in size (i.e., installed cogeneration capacity) and use identical amounts of natural gas to fire the units. However, the baseline scenarios vary in accordance with current conditions and plausible alternatives that would have been undertaken if the project would not be constructed. Overall emission reductions are determined by the difference between the baseline GHG emissions minus the emissions that are due to the two new respective projects. Table 5 provides a summary of the results.

Table 5. Comparative Summary of GHG Emission Reductions for the Cases Investigated

		ANNUAL CO_2-E (Tonnes/year)	
		CASE # 1	**CASE # 2**
BASELINE SCENARIO	*Electricity Equivalent Emissions*	162,315	161,959
	Electricity Grid Displacement	801,496	406,103
	Steam Equivalent Emissions	153,678	353,802
	Total Baseline Emissions	**1,117,489**	**921,864**
CHP PROJECT	***Total Direct Emissions***	840,773	463,373
NET GHG EMISSION REDUCTIONS		**276,716**	**458,491**

SUMMARY

The decade-long effort by the Oil & Natural Gas industry has resulted in guidelines that provide credible and consistent GHG emission calculation methods, and promote a systematic approach to GHG emissions, and emission reductions, characterization. This is a vital first step to understanding the nature of the emission sources and to crafting effective methods for their mitigation or control.

The former version of the API Compendium was compiled by the industry in the context of robust voluntary reporting programs. The revised API Compendium - in conjunction with the Uncertainty Document - are now at the forefront of emission estimation methods both for the Oil & Natural Gas sectors as well as for fossil fuel based general combustion sources, and are applicable to both voluntary and emerging mandatory reporting regimes[16]. Similarly, the Project Guidelines provide a consistent framework for assessing the GHG emission reductions associated with families of GHG reduction projects that are common to the Oil & Natural Gas industry, and might also be applicable to sectors such as power generation, petrochemical manufacturing and others.

The Oil & Natural Gas industry sector plans to continue its outreach and disseminate these guidelines broadly, as well as continue to develop additional guidance for selected industry sub sectors. The industry is participating in collaborative research to obtain new and improved emission factors data for targeted operations. It will also continue to participate in public forums with governmental and intergovernmental organizations to address emerging reporting issues and provide pertinent technical information for such discussions.

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