

APPLICATION OF THE API COMPENDIUM TO EXAMINE POTENTIAL METHANE EMISSION REDUCTION OPPORTUNITIES

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ABSTRACT

To assist its members and to serve as a reference source, the American Petroleum Institute (API) developed a *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* (API, 2001) that documents calculation techniques and emission factors for developing greenhouse gas (GHG) emissions inventories for oil and gas industry operations. In addition to inventory development, the methodologies provided in the Compendium are also useful for analyzing GHG emission reductions. Further understanding of the reduction potential associated with a variety of voluntary actions is valuable to the oil and gas industry, as well as API member companies. In a continued effort to enhance the real-world application of the Compendium, API is examining the applicability of the Compendium to assess emission reductions from a number of specific projects.

This paper presents findings from this study to evaluate, quantify, and document emission reductions. Through quantitative examples targeted toward CH₄ reductions, this paper examines the applicability of the Compendium and potential methodological issues. It discusses technical considerations associated with baseline assessment, as well as estimating pre- and post-project emissions.

OBJECTIVES

GHG emission reductions enhance not only environmental performance, but also economic performance, where reductions stem from improved energy efficiency or reduced CH₄ emissions. Further understanding of the emissions reduction potential associated with such activities is valuable in promoting industry best practices.

The objectives of this study on quantifying potential emission reductions opportunities for specific industry practices, were:

1. To determine the adequacy of the API Compendium to estimate GHG emissions and emissions reductions from specific GHG emission reduction project examples;
2. To identify modifications to the Compendium to accommodate the calculation and documentation details associated with the reduction case studies; and
3. To illustrate the considerations and calculation methodologies associated with different types of emission reductions.

The use and applicability of the API Compendium to evaluate GHG emission reduction projects are examined through specific case studies. However, the reader should note that the approaches presented will require some customization for real-world application to account for project-specific factors and requirements of applicable registration/certification organizations. It is also important to recognize that the reduction case studies may not be applicable to all locations and the emission estimates may not be representative of actual applications due to simplifying assumptions.

GENERAL GUIDELINES FOR QUANTIFYING GHG EMISSION REDUCTIONS

Determining GHG emission reductions associated with a specific activity requires the following steps:

1. Establish a reference case as the basis for comparison with the reduction project.
2. Identify and quantify the effects of the project, including direct and indirect emission increases and decreases.
3. Estimate emission reductions as the difference between the reference case and post-project emissions.

At the 7th meeting of the Conference of Parties in Marrakech (COP 7, October/November 2001), the rules for Clean Development Mechanisms (CDM) were defined and more detailed guidance was developed for project design and reduction credit accounting. The resulting modalities and procedures define project baselines as “the scenario that reasonably represents the anthropogenic emissions by sources of GHGs that would occur in the absence of the proposed project activity” (UNFCCC, 2001). Due to certain complexities in project boundaries, the baseline scenario may need to reflect what would likely have occurred in the absence of the project, in addition to including the activities conducted prior to the project (i.e., pre-project activities). Each reduction project requires evaluation on a case-by-case basis to determine the most likely baseline scenario.

Other technical issues encountered in considering emission reduction projects include: imported and/or exported energy; direct versus indirect affects of the project; the duration over which the emission reductions apply (i.e., permanence), and changes in baseline conditions. Details and the practical application of these procedures are still evolving. In the absence of widely accepted standards for quantifying GHG emission reductions and establishing reduction project baselines, emerging trading programs and registries are developing their own requirements. Ultimately, the baseline definition will be guided by the objectives of the particular program or registry.

GHG EMISSION REDUCTION PROJECT CASE STUDIES

An initial list of case studies was compiled based on input from the API workgroup members and other reported petroleum industry initiatives (API, 1999; EIA, 1996; EPA, 2002). Eight specific projects were investigated, representing potential reduction opportunities of CO₂ and/or CH₄ emissions for different sectors of the petroleum industry. These example case studies

were used to examine various technical issues associated with quantifying emission reductions and to illustrate the use of the Compendium. It is important to recognize that the reduction case studies selected may not be applicable to all locations and the emission estimates may not be representative of actual applications due to simplifying assumptions.

Further details and illustrative estimates on four of the selected emission reduction case studies are presented in the following subsections.

FUGITIVE LEAK DETECTION AND REPAIR

Certain equipment components develop leaks over time due to wear, heat, pressure, moisture, or other process conditions. Other equipment, such as mechanical seals, are designed to leak a small amount. These leaks of process fluid (either gas or liquid) through sealed surfaces are generally referred to as fugitive emissions. In the oil and gas industry, fugitive emissions can be a significant source of GHG emissions in operations where CH₄ is the primary constituent of the process stream.

Leak detection and repair (LDAR) or directed inspection and maintenance (DI&M) programs provide an effective means for reducing fugitive emissions. LDAR consists of an initial evaluation of facility equipment to identify and measure leaking components. This information is used to prioritize repairs and subsequent leak surveys.

This case study examines potential emission reductions associated with LDAR programs at two facilities:

1. A natural gas production field; and
2. A natural gas pipeline compressor station.

Table 1 summarizes the results of the two scenarios examined.

PNEUMATIC DEVICE RETROFIT OR REPLACEMENT

Pneumatic devices use compressed gas as the motive force to perform process operations, such as controlling pressure, flow rate, temperature, or liquid level. Pneumatic devices operated with natural gas have been identified as a potentially significant source of CH₄ emissions (Shires and Harrison, 1996).

This case study estimated potential emission reductions associated with four reduction project scenarios:

- Implementing maintenance practices, including leak repair, device tuning, and reducing the device supply pressure;
- Replacing high-bleed devices with low-bleed devices;
- Retrofitting pneumatic devices to eliminate the continuous pilot bleed rate; and
- Substituting compressed air for natural gas.

Potential emission reductions may be estimated for each of these various options using site data or measured pneumatic device gas consumption rates.

Table 2 presents a summary of estimates for the scenarios examined as part of this case study example, using assumptions about the type and quantity of pneumatic devices associated with a hypothetical oil and gas production facility.

GLYCOL DEHYDRATION PROCESS OPTIMIZATION

Glycol dehydrators are commonly used in natural gas production to remove moisture from the gas stream. The gas is dehydrated to pipeline specifications through continuous absorption of moisture by glycol, most commonly triethylene glycol (TEG).

In many glycol dehydrators small gas-assist pumps are used to circulate the glycol. In these pumps, natural gas is intentionally entrained at high pressures with the rich glycol leaving the absorber. The glycol/gas mixture is a source of pressure energy, which is used to pump the low-pressure lean glycol back into the absorber. The spent gas is eventually exhausted to the atmosphere through the regenerator vent and is a significant source of CH₄ emissions from the dehydrator. Additionally, because of leakage of rich glycol across the piston O-rings from the high pressure side to the low-pressure side of the pump, dehydrator efficiency is reduced. This often requires over circulation of glycol to maintain the required water removal rate, resulting in further CH₄ absorption by the glycol and corresponding emissions from the regenerator vent.

Estimated emission reductions for the following dehydrator optimization scenarios are summarized in Table 3.

- Replacement of gas-assist pumps with electric pumps. This option is attractive if a source of electricity is already available on site. Electric pumps eliminate CH₄ emissions from the pump and the possible contamination of the lean glycol. Glycol circulation rates can be reduced due to improved dehydrator efficiency, further reducing CH₄ emissions from the regenerator vent.
- Addition of a flash tank. The water-rich glycol leaving the bottom of the absorber passes through the pump to a flash tank where much of the lighter hydrocarbons entrained in the glycol at high pressure are separated from the glycol. Depending on the quality of the gas and the fuel requirements on-site, significant CH₄ emission reductions can be realized if the flash gas is introduced in the pipeline, or replaces existing gas usage at the facility (i.e., used as fuel or stripping gas). Flaring the flash gas will also result in emission reductions where the quality of the gas is poor.
- Use of a glycol regenerator still condenser and condensate separator to recover the natural gas liquids. The non-condensable gas from the condensate separator that contains mostly CH₄ can be used as fuel at the facility.

RECOVERY OF PRODUCTION TANK FLASHING LOSSES

In the exploration and production (E&P) sector of the oil industry, flashing losses from crude oil storage tanks can be a significant source of CH₄ emissions. Light hydrocarbons, such as CH₄, are entrained in underground

crude oil. As the crude oil is produced and processed through separators and/or heater treaters, many of the dissolved lighter hydrocarbons are removed. Flashing losses occur when the crude oil passes from the separator or heater treater, with operating pressures typically ranging from 20 to 60 psig, to a storage tank at atmospheric pressure.

Vapor recovery units (VRUs) can capture more than 95% of the hydrocarbon emissions from crude oil storage tanks (EPA, 1997). In addition to emission reductions, vapor recovery has the added benefit of economic savings in the form of recovering valuable gas that can be used as fuel for on-site operations or sold for off-site use. However, there are operating conditions that must be considered in determining whether recovery of the hydrocarbon emissions is feasible, including:

- Gas flow rate – flow rates over 50,000 scf/day are ideal; flow rates less than 10,000 scf/day are generally not economically feasible. A VRU can be installed to serve multiple tanks to achieve the desired flow rate or to stabilize process fluctuations.
- Variability of the crude flow rate, and thus the emission rate – intermittent gas flow rates can be problematic. If the flow rate is too low, it may be necessary to vent or flare the gas.
- Location conditions – compression may be required to reach the operating pressure of the gathering pipeline. Recent testing of a venturi jet eductor to capture flash gas shows promise for systems with low-pressure vent streams.

This case study examines potential emission reductions associated with the installation of a VRU on a theoretical crude oil tank. The calculations are based on two important assumptions that may vary for specific applications. First, it assumes that a steady source and sufficient quantity of hydrocarbon vapor are available. Second, the case study also assumes that a gathering pipeline is available to route the collected vapors offsite, or that the collected vapors can be used for fuel on-site.

The emission reduction calculations account for the energy requirements (and associated CH₄ and CO₂ emissions) of the VRU compressor, either from purchased electricity or on-site generation. Emission estimates are adjusted for the additional emissions resulting from VRU downtime. Emission reductions associated with a venturi jet eductor vapor recovery system are also examined (COMM Engineering's EVRU™ system). Table 4 summarizes the results for the different reduction scenarios.

CONCLUSIONS

Reductions in energy usage can result in reduced operating costs. Similarly, reduced CH₄ emissions can translate into increased natural gas production/recovery. Due to the competitive business environment and pressure to control costs, oil and gas operators are taking steps to reduce energy usage and improve the efficiency of their operations. Demonstrating GHG emission reductions associated with these activities is an added benefit. This project quantified emission reductions for several oil and gas industry

example case studies and provided insight into characterizing emission baselines and examining different reduction scenarios. Conclusions from this study include the following:

- Specific emission reduction opportunities may not be applicable to all locations, and potential emission reductions will vary for each situation.
- Emission reductions require examining emissions from specific sources for the purpose of quantifying emissions before and after a reduction project has been implemented.
- All emission sources that are likely to be influenced, either directly or indirectly, by a reduction project should be accounted for when considering the overall impact of the project on GHG emissions.
- Guidance for emission reduction reporting is beginning to evolve. Ultimately the selection of an appropriate approach depends on location-specific conditions, how the emission reductions will be used, any associated reporting specifications, and requirements of the host country and the buyer of emission reductions in the carbon market.
- Although the API Compendium was targeted toward developing emission inventories, many of the methodologies are applicable to quantifying emission reductions. However, there are certain emission reduction projects, such as pneumatic devices, in which the current estimation techniques provided by the Compendium do not provide sufficient detail for quantifying pre- and post-project emissions.

Enhancements to the Compendium to address these findings will be considered for the next release. (To obtain a copy of the current version see: www.global.his.com.) API welcomes a continuing open exchange of information and a broad discussion of GHG emission estimation methodologies. It is hoped that this process will achieve better harmonization of emission protocols and enable improved global comparability of emission estimates.

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Table 1. Summary of Emission Reductions from LDAR Case Study Scenarios

Hypothetical Scenarios	Estimated Emission Reduction^a
Natural gas production field with more than 13,000 fugitive components in gas or light liquid service	7,700 tonnes CO ₂ Eq. for 1-year LDAR cycle
Natural gas pipeline compressor station with approximately 7,700 fugitive components in gas service	1,900 tonnes CO ₂ Eq. for 1-year LDAR cycle

^a Note: estimated reductions are based on assumed conditions for the example case study scenarios and may not be representative of actual reductions for real-world applications.

Table 2. Summary of Emission Reductions from Pneumatic Device Case Studies

Hypothetical Baseline Scenario	
Oil and production operations with 20 liquid level controllers and 180 pressure controllers	
Baseline pneumatic device emissions, tonnes CO ₂ Eq.	23,444
Potential Reduction Scenarios	
Improved maintenance	35%
Replace high-bleed devices with low-bleed devices	93%
Retrofit high-bleed devices to eliminate pilot bleed rate	99%
Replace natural gas with compressed air ^b	99.5% ^b
Replace high-bleed devices with self-contained devices	100%

^a Note: percent reductions are based on assumed conditions for the example case study scenarios and may not be representative of actual reductions for real-world applications.

^b For this scenario, post project emissions are indirect due to electricity consumption, while baseline emissions are direct. Replacing natural gas with compressed air results in a 100% net decrease in direct emissions, and a 0.5% net increase in indirect emissions.

Table 3. Summary of Emission Reductions from Dehydrator Optimization Case Studies

Hypothetical Baseline Scenario	
Dehydrator treats 20 MMscfd of gas containing 83 vol. % CH ₄ , 3 vol. % CO ₂ Operating pressure = 800 psig; Water removed = 53 lb/MMscf gas Pump gas usage = 4.5 scf gas entrained per gallon TEG TEG design circulation ratio = 3 gal. TEG/lb water removed Overcirculation ratio (OC) = 2 (i.e. two times the required circulation rate)	
Baseline scenario emissions, tonnes CO ₂ Eq./yr	3,500
Potential Reduction Scenarios	Estimated % Emission Reduction^a
Replace gas-assist pump with electric pump – eliminates CH ₄ emissions from gas entrained in the glycol and reduces glycol recirculation rate	84%
Retain gas-assist pump; Install flash tank	
Recovered gas is directed to pipeline	89%
Recovered gas is used as on-site fuel (reduces fuel requirements)	90%
Recovered gas is flared	74%
Retain gas-assist pump; Install flash tank and still vent condenser and separator; Recovered gas is used as on-site fuel (reduces site fuel requirements)	99.5%

^a Note: percent reductions are based on assumed conditions for the example case study scenarios and may not be representative of actual reductions for real-world applications.

Table 4. Summary of Emission Reductions from Tank Flashing Loss Case Studies

Hypothetical Baseline Scenario	
Oil production rate = 1600 bbl/day; API gravity = 43.2° Produced crude oil is sent to four 1000 bbl tanks where the flash gas is emitted.	
Baseline scenario emissions, tonnes CO ₂ Eq./yr	2,028
Potential Reduction Scenarios	Estimated % Emission Reduction^a
VRU is installed; Flash gas is vented to the atmosphere during downtime	
Electricity is purchased from the grid	87.4%
Electricity is generated on-site	86.9%
VRU is installed; Flash gas is flared during downtime	
Electricity is purchased from the grid	75.7%
Electricity is generated on-site	75.2%
EVRU ^{TMb} venturi eductor device is installed; No electricity requirements; No downtime	100%

^a Note: percent reductions are based on assumed conditions for the example case study scenarios and may not be representative of actual reductions for real-world applications.

^b Information on the Environmental Vapor Recovery Unit (EVRUTM) provided by COMM Engineering.