# QUANTIFICATION PROTOCOL FOR THE REDUCTION OF METHANE EMISSIONS FROM OIL AND GAS FACILITIES

Public Review Document

## Acknowledgements

This protocol is based on the Technical Seed Document entitled *A Protocol for Methane Emission Reductions for Greenhouse Gas Credits* dated October, 2008. This document was prepared as a collaborative effort by Keyera, Husky, EnCana, Shell and Nexen for submission to Alberta Environment.

## Disclaimer

The following protocol document was prepared for Alberta Environment. The document will undergo a round of technical review and a broader round of stakeholder review through 2009. Future versions of the protocol document will incorporate the feedback from this review process.

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## 1.0 Project and Methodology Scope and Description

This quantification protocol is written for the oil and gas industry or the methane emission reduction project developer. The opportunity for generating carbon offsets with this protocol arises from the direct and indirect reductions of greenhouse gas (GHG) emissions resulting from the identification and reduction of methane emissions from venting and other fugitive emissions at oil and gas facilities. Sources of fugitive emissions at oil and gas facilities may include equipment leaks, tanks, instrument venting, etc[1]. Some familiarity with, or general understanding of, the operation of oil and gas production, processing and transmissions facilities is assumed.

Note that this protocol only quantifies changes in methane emissions. This approach was selected for a variety of reasons. First and foremost, fugitive methane emissions represent the single largest source of non-throughput dependent emissions at oil and gas production and transmission facilities. Fugitive $CO_2$ and $N_2O$ emissions are negligible[2]. Given that that project activity serves to reduce fugitive emissions, it is also conservative to exclude consideration of vented $CO_2$. In addition, it is conservative not to include either $CO_2$ or $N_2O$ in the project scenario, as any reduction in fugitive methane emissions may also result in a decrease in $CO_2$ and / or $N_2O$ emissions. For example, reduced venting at sour gas facilities may result in lower $CO_2$ emissions from venting.

Projects included under this protocol must be able to demonstrate a reduction in methane emissions using direct quantification, with virtually continuous monitoring and complete coverage of the project site[3]. Projects which rely exclusively on traditional leak detection methods such as the bag and stopwatch or “sniffing” techniques are excluded from this protocol, as these methods do not fulfill the requirement of virtually continuous monitoring.

### 1.1 Protocol Scope and Description

This protocol quantifies emission reductions created by the identification, quantification, and reduction of planned and / or unplanned fugitive methane emissions from oil and gas production and transmission processes.

*Planned Emissions*

Planned emissions are known emissions that result from operational practices. Operational practices that use process gas for “blanketing purposes”, or equipment that uses the pressure of the process gas as energy to drive the equipment (valves, pumps etc.) and then releases it to the atmosphere, are examples of planned emissions. Additionally, some venting practices are

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[1] Canadian Association of Petroleum Producers (CAPP). (2003). CH4 and VOC Emissions: Volume 4. Retrieved at http://www.capp.ca/raw.asp?x=1&dt=NTV&e=PDF&dn=84183

[2] CAPP. (2003). *CH4 and VOC Emissions: Volume 4*.

[3] The definitions of the term ‘virtually continuous’ is defined in Section 1.2

planned emissions that can result in intermittent and / or highly variable emission rates that are difficult to quantify, but could afford significant reductions of GHGs if reduced.

Challenges exist for quantifying planned emissions as emission rates can be highly variable and / or intermittent. This is likewise the case with most venting situations where it is not usually a problem to locate the source of the vents, but determining the amount of gas being vented is difficult.

*Unplanned Emissions*

A relatively small number of fugitive sources usually accounts for the vast majority of the overall fugitive emissions at natural gas facilities. As a result, fugitive emissions are very difficult to quantify with certainty because they are dominated by a small number of unstable sources in unpredictable locations. Experience has shown that these random large fugitive emissions may go undetected even at facilities that are using the US EPA's stringent "Method 21" protocol that requires all potential leaking components to be visited at a prescribed frequency[4].

Methane emissions from oil and gas facilities are difficult to assess given the large number of potential sources, random occurrence, transient behaviour, poor correlation of emissions with facility activity levels, diffuse nature, and the difficulty of area air monitoring to detect these emissions[5]. As such, there is a challenge associated with quantifying and claiming credit for fugitive methane emissions due to these characteristics (i.e. location, size, variability, and frequency), which are generally unknown.

Given that planned and unplanned emissions are dominated by a small number of sources with unpredictable locations, as described above, the key challenge is in accurately quantifying emission reductions. This requires quantification of the source through direct measurement. Further, since source locations are unpredictable surveillance of the entire site is required. Given the potential variability over time, virtually continuous monitoring of emissions is also necessary to ensure accuracy. As such, to achieve a high level of certainty that an emission reduction has occurred, the methodology selected for the quantification and monitoring of fugitive emissions in the project condition is the use of a system with virtually continuous monitoring, direct measurement and complete site coverage.

A summary of the technologies available for virtually continuous monitoring at the time of writing of this protocol is provided in Appendix A. It is anticipated that additional technologies may become available during the protocol applicability period. These technologies would also be applicable, as long as they provide direct measurement, virtually continuous monitoring and

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[4] Petroleum Technology Alliance Canada Technology for Emission Reduction and Eco-Efficiency(TEREE) Steering Committee. (2007). *Review and Update of Methods Used for Air Emissions Leak Detection and Quantification*.

[5] ibid

complete site coverage, and meet the minimum measurement and monitoring requirements of this protocol. **FIGURE 1.1** offers a process flow diagram for a typical project.

Current regulations governing methane emissions from oil and gas facilities in Alberta include Alberta Energy Resources Control Board (ERCB) Directive 060 (ERCB, 2006). The emission reductions contemplated under this protocol must be incremental to the emission reductions required by the above document.

Regulatory incrementality will be demonstrated by discounting emission reductions by an Improvement Factor, to account for the impacts of implementing a Direct Inspection and Maintenance (DI&M) leak detection and repair program that meets the requirements of the Directive. This industry average Improvement Factor will be applied for each of the eight years of the registration period, and represents the percentage decrease in fugitive methane emissions that would have occurred in the absence of the project as a result of the Directive.

No discount is required for emission reductions generated prior to January 1st, 2010, as this is prior to the date when Directive 060 requires a DI&M program to be fully implemented.

Due to the use of virtually continuous monitoring and complete site coverage, it is anticipated that projects using measurement and monitoring techniques consistent with this protocol will be able to detect and fix sources of methane emissions that would not have been detected using the methods used in a typical DI&M program that meets the requirements of the Directive.

**Protocol Approach:**

This protocol applies to projects where methane emissions are from oil and gas facilities and would otherwise have been emitted to the atmosphere. This protocol serves as a generic 'recipe' for project developers to follow in order to meet the measurement, monitoring and GHG quantification requirements.

Measurements may be inclusive of methane emissions from the following key sources[6]:

- Planned and unplanned venting; and
- Fugitive methane losses from the following sources:
    - Fittings and seals;
    - Instrument venting;
    - Glycol dehydrators;
    - Vapour from oil batteries;
    - Plant tank venting; and
    - Non routine venting (i.e. equipment failures, pressure releases), etc.

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[6] Canadian Association of Petroleum Producers (CAPP). (2003). *Calculating Greenhouse Gas Emissions*

The baseline condition for this protocol has been identified as the facility's methane emissions (planned and unplanned) during operation of the oil and / or gas production and / or transmission facility prior to project implementation. The protocol approach includes determination of the baseline condition using an industry standard approach (i.e. the Canadian Association of Petroleum Producers (CAPP) Generic Fitting Count Method or Canadian Energy Parternership for Environmental Innovation (CEPEI) Average Emission Factors Method) that is more rigorous than the industry standard approach for facility reporting under Alberta's Specified Gas Emitters Regulation ( i.e. the CAPP Short Form Method).

The CAPP Generic Fitting Count Method / CEPEI Average Emission Factors Method is employed to avoid the errors associated with using a simple production-based emission factor approach such as the Short Form Method or a partial baseline monitoring period, given the significant variability of fugitive emissions over time.

The project condition for this protocol has been identified as the facility's methane emissions during operation of the facility following project implementation. Project activities to reduce methane emissions may include reduced venting, detection and repair of fugitive equipment leaks, facility consolidation activities, etc. that would not have been conducted in the absence of the project. Project emissions are monitored virtually continuously using an applicable technology that provides complete site coverage and direct measurement of methane emissions at the facility level.

In practice the primary output of methane from venting and fugitive losses would be to sales gas, with gas only being flared during emergency provisions. However, at facilities that do not sell methane as an end product (i.e. gas production facilities) flaring may be the only option. It is therefore assumed that at these facilities all methane whose emission is avoided in the project condition is flared. This is conservative. Alternatively, the protocol has a flexibility mechanism that allows the project proponent to demonstrate that gas is not flared.

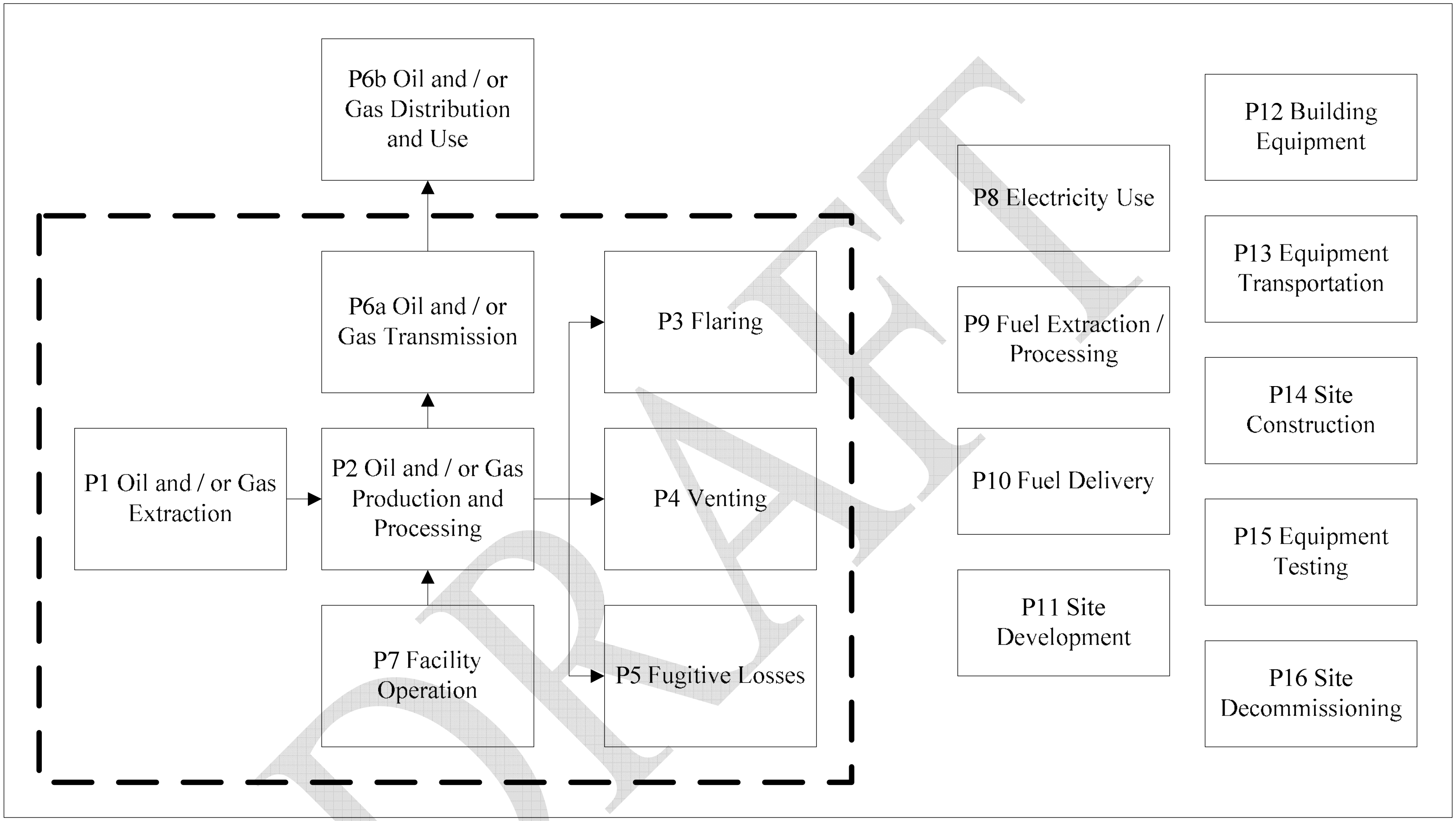
Note that methane emissions may go up in some months due to facility shutdowns, etc. and facility methane emissions for each month of a given year must be included in the facility's emission profile. Project proponents may not exclude months when methane emissions have increased.

Project emissions are then compared with the quantity of methane emitted in the baseline. Emission reductions are generated based on the difference between project and baseline methane emissions at the facility. As discussed, from January 2010 onwards emission reductions are then discounted by an Improvement Factor, to account for the impacts of implementing a DI&M program as required by ERCB Directive 060. This ensures that emission reductions are surplus to regulations.

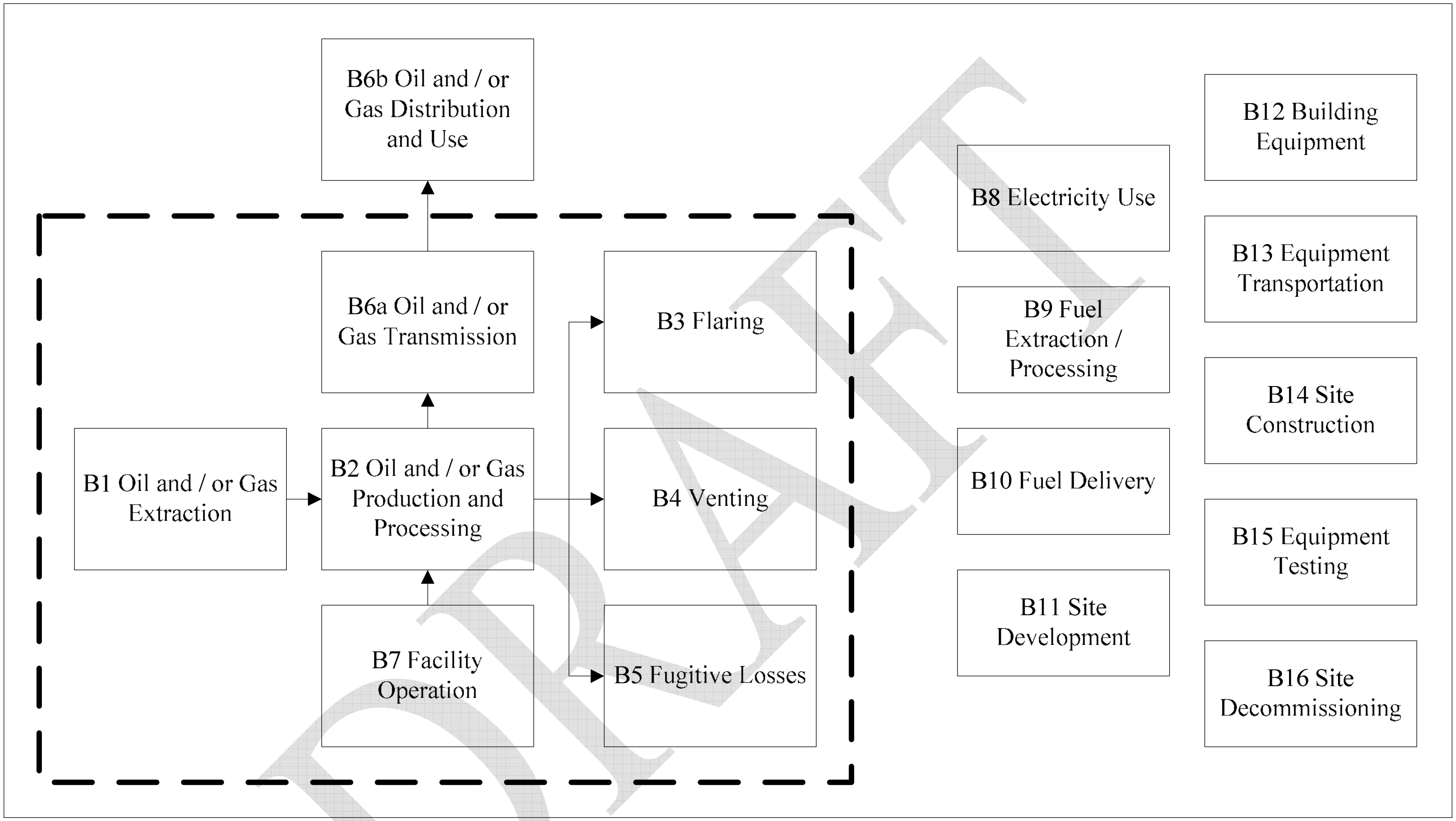
This quantification approach provides the most conservative and accurate approach to project and baseline determination of methane emissions that is possible given currently published data.

Based on this approach, a methodology has been established to mitigate and minimize the potential for error and provide accurate and conservative accounting mechanisms, while maintaining usability and practicality.

**FIGURE 1.1: Process Flow Diagram for Project Condition**



1 **FIGURE 1.2: Process Flow Diagram for Baseline Condition**



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3

**Protocol Applicability:**

To demonstrate that a project meets the requirements under this protocol, the project developer must provide evidence that:

1. The fugitive emission reduction project results in the removal of emissions that would otherwise have been released to the atmosphere, as indicated by virtually continuous monitoring of emissions in the project condition. Criteria for selection of an appropriate monitoring methodology are included in Appendix A;
2. To ensure functional equivalent between the project and baseline conditions, the fugitive emission reduction project must not require any re-permitting of the facility. If re-permitting does occur at the facility that is unrelated to the project activity, a new baseline should be established;
3. The emissions captured under this protocol must not also be reported under other applicable protocols. This is important, given that this protocol uses an overall site methane emission calculation. Methane emission reductions reported under any other protocols such as the Engine Fuel Gas Management and Vent Gas Capture protocols must be subtracted from the total reductions calculated under this protocol;
4. The emission reductions achieved by the project must be additional to those required by Alberta regulations. This is accomplished by discounting emission reductions by an Improvement Factor to account for the impacts of implementing a Direct Inspection and Maintenance (DI&M) program that meets the requirements of ERCB Directive 060;
5. The project proponent must provide a complete list of process changes, repairs or other actions taken to reduce methane emissions. Further detail is provided in the quality assurance and quality control section of the protocol (Section 2.6.2);
6. Reductions in methane emissions resulting from business as usual activities and required equipment replacements must be discounted from baseline emissions. These may include activities such as equipment decommissioning and installation of new equipment that would have been conducted under business as usual activities (i.e. old equipment being switched out), process adjustments to account for changes in facility throughput, source gas composition, etc., in-sourcing or outsourcing of operations, purchase or sale of significant emission sources, etc. If evaluation indicates that the change is material (i.e. greater than 5% of base year emissions) and would have occurred in the absence of the project, the baseline emission intensity should be modified to reflect these changes. Justification should be provided by the project proponent to explain any changes to the facility's baseline emission intensity;
7. In addition to quantifying emissions following the approach outlined in Table 2.5, project proponents are also required to quantify large unplanned sources of fugitive methane emissions before and after repair, using an appropriate traditional leak

measurement method and following the methodology outlined in Appendix C[7]. These records must be submitted as an appendix to the Project Report;

8. The quantification of reductions achieved by the project is based on actual measurement and monitoring (except where indicated in this protocol) as indicated by the proper application of this protocol; and
9. The project must meet the requirements for offset eligibility as specified in the applicable regulation and guidance documents for the Alberta Offset System.

**Protocol Flexibility:**

Flexibility in applying the quantification protocol is provided to project developers in the following ways:

1. Instead of assuming that all methane captured in the project condition is flared on-site and released as $CO_2$ at facilities that do not sell methane as an end product, project proponents may provide evidence to demonstrate that gas is not flared. Evidence may include the use of schematic or process flow diagrams to demonstrate that gas could not have been flared based on the location of the emission source, an audit of facility emissions, etc.
2. For some project configurations, complete site coverage may not be an appropriate or feasible means of quantifying a facility's emissions. As such, project proponents may define a limited measurement area / project boundary. This approach is only an option in cases where it can be justified that the emission impacts from project activities are confined within the newly defined measurement area / project boundary. Justification should be provided to explain how the chosen approach is conservative and represents a reasonable deviation from the protocol's methodology;
    a. This approach may be applicable to projects involve a limited number of processes / equipment. For example, replacing wet seals with dry seals on turbine compressors, modification of procedures in order to reduce natural gas venting during planned maintenance events, etc.;
3. For some project configurations, virtually continuous monitoring may not be a feasible means of quantifying the Project's emissions. As such, project proponents may apply a monitoring frequency other than what is outlined in this protocol. The monitoring frequency selected must allow for a level of accuracy that does not differ substantively from the accuracy presumed for virtually continuous monitoring. Justification should be provided to explain how the approach is conservative and represents a reasonable deviation from the protocol's methodology;

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[7] Note that this requirement has been included at the request of AENV, and as a means to compare the emission reductions generated by a given project using the industry standard baseline approach vs. instantaneous measurement of the fugitive emission source before and after repair.

   a. This approach may be applicable to projects at facilities that involve a limited number of processes / equipment such as single well batteries, satellite batteries, and field facilities; and

   b. This approach may also be applicable at facilities where methane emissions are not found to vary substantively over time. In this case, measurements would be used by the project proponent to create an annual methane emission profile for the facility.

4. Project proponents may apply the CAPP Specific Fitting Count method if it produces a more conservative estimate of the facility's baseline emissions. If the Specific Fitting Count method is less conservative, the CAPP Generic Fitting Count Method must be used.

If applicable, the developer must indicate and justify why flexibility provisions have been used.

## 1.2 Glossary of New Terms

| | |
|---|---|
| Functional Equivalence | The Project and the Baseline must provide the same function and quality of products or services. This type of comparison requires a common metric or unit of measurement for comparison between the Project and Baseline activity (refer to the Project Guidance Document for the Alberta Offset System for additional detail).<br>Functional equivalence in this protocol is a complicated mechanism given that throughput is not an appropriate unit of functional equivalence for fugitive emissions as they are not dependent on throughput but on the number of sources, hours operational, age of equipment, etc[8].<br>Functional equivalence is demonstrated by quantifying the volume of fugitive methane emissions in the baseline and following project implementation. The difference between the two values represents the quantity of methane reduced as a result of project implementation. The measured unit for determining functional equivalence is the mass (kg) or volume ($m^3$) of methane emitted. This common metric allows for analysis and comparison of total facility methane emissions.<br>For functional equivalence to be applicable in this scenario the facility must ensure that no facility re-permitting is required. This will ensure that emission reductions are based on actual reductions of methane emissions within the facility as opposed |

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[8] Canadian Association of Petroleum Producers (CAPP). (2003). CH4 and VOC Emissions: Volume 4.

| | |
|---|---|
| | to process or production changes which give the impression of methane emission reductions and would have occurred in the baseline scenario. If re-permitting does occur at the facility, a new baseline would need to be established in order to continue using the protocol. |
| Planned Emissions: | Known emissions that result from operational practices and are generally stated in production accounting records. Examples include using process gas for blanketing purposes, and planned venting. The location of planned emissions is known, but the volumes may be difficult to quantify. |
| Unplanned Venting: | According to the Canadian Association of Petroleum Producers (CAPP) sources of unplanned venting include glycol dehydrator off-gas, loading/unloading losses, storage losses, pneumatic devices (e.g., chemical injection pumps, natural gas operated instrumentation), compressor start gas, purge gas and blanket gas that is discharged directly to the atmosphere and gas vented from drill-stem tests”[9]. |
| Fugitive Emissions: | Unintentional greenhouse gas emissions of unknown quantities from unknown locations. According to the Canadian Association of Petroleum Producers (CAPP) fugitive emissions include fugitive equipment leaks, accidents and equipment failures. Equipment may leak due to normal wear and tear, poor design or incorrect installation. Fugitive emissions may occur at any point during the extraction, processing, and transport of raw or processed oil and natural gas. Typical sources of equipment leaks include: threaded and flanged connections, valve stem packing leaks, leakage past valve seats to the atmosphere, compressor seals, pump seals, pressure regulator vents and sampling ports. Accidents and equipment failures include: spills, pipeline ruptures, gas migration and surface casing vent flows[10]. |
| Virtually Continuous: | Virtually continuous data collection is defined as continuous monitoring of facility emissions with a data point being taken and / or signals being averaged and recorded at least hourly. |

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[9] CAPP. (2005). *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 5, Compendium of Terminology, Data Sources, etc.*

[10] ibid

## 2.0 Quantification Development and Justification

The following sections outline the quantification development and justification.

### 2.1 Identification of Sources and Sinks (SSs) for the Project

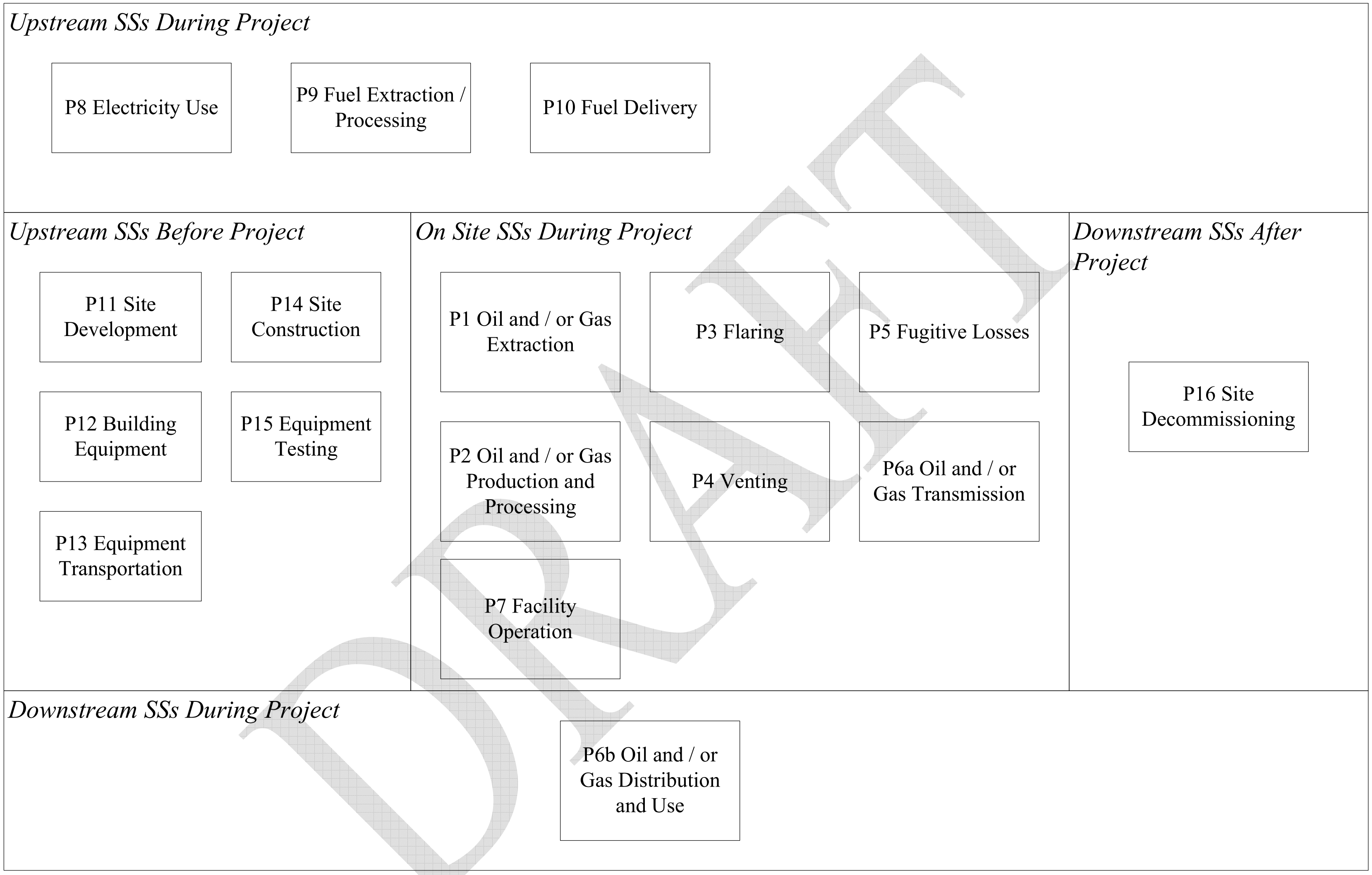
SSs were identified for the project by reviewing the seed document and relevant industry guidelines for calculating GHG emissions. This process confirmed that the SSs in the process flow diagrams covered the full scope of eligible project activities under the protocol.

Based on the process flow diagrams provided in **FIGURE 1.1**, the project SSs were organized into life cycle categories in **FIGURE 2.1**. Descriptions of each of the SSs and their classification as controlled, related or affected are provided in **TABLE 2.1.**

The definitions for classifying SSs, based on Guidance provided by Environment Canada, are as follows:

| | |
|---|---|
| Controlled: | The behaviour or operation of a controlled SS is under the direction and influence of a project proponent through financial, policy, management, or other instruments. |
| Related: | A related SS has material and / or energy flows into, out of, or within a project but is not under the reasonable control of the project proponent. |
| Affected: | An affected SS is influenced by the project activity through changes in market demand or supply for projects or services associated with the project. |

## FIGURE 2.1: Project Element Life Cycle Chart



1 **TABLE 2.1: Project SSs**

| 1. SS | 2. Description | 3. Controlled, Related or Affected |
|---|---|---|
| **Upstream SSs during Project Operation** | | |
| P8 Electricity Use | Electricity may be required to power equipment throughout the extraction, processing and transport processes. The quantity of power consumed and the source of electricity would need to be tracked. | Related |
| P9 Fuel Extraction and Processing | Each of the fuels used throughout the project may need to sourced and processed. This will allow for the calculation of the greenhouse gas emissions from the various processes involved in the production, refinement and storage of the fuels. The total volumes of fuel for each of the SSs are considered under this SS. Volumes and types of fuels are the important characteristics to be tracked. | Related |
| P10 Fuel Delivery | Each of the fuels used throughout the project may need to be transported to the site. This may include shipments by tanker or by pipeline, resulting in the emissions of greenhouse gases. It is reasonable to exclude fuel sourced by taking equipment to an existing commercial fuelling station as the fuel used to take the equipment to the sites is captured under other SSs and there is no other delivery. | Related |
| **Onsite SSs during Project Operation** | | |
| P1 Oil and / or Gas Extraction | The extraction of oil and gas can be accomplished using various equipment and processes requiring fuel and electricity inputs. The emissions resulting from these inputs are captured under this SS. The quantity of power, fuel volume and fuel types would be tracked to determine equivalence with the baseline condition. | Controlled |
| P2 Oil and / or Gas Production and Processing | Operation of the oil/gas facility may require the use of mechanical equipment, pumps and pressure equipment. This may require several energy inputs such as electricity, natural gas and diesel. Quantities and types for each of the energy inputs would be tracked. | Controlled |
| P3 Flaring[11] | Flaring is a common means of disposing of waste gas at oil and gas facilities. Flaring is normally used at sour gas facilities where waste gas contains toxic components and for both high and low pressure waste gas streams. From time to time gas may be flared at the baseline site as a result of emergency shut-down, maintenance or other operational conditions. Emissions of greenhouse gases would be contributed from the combustion of the gases as well as from any fuel gas used in flaring to ensure more complete combustion. Quantities of gas being flared and the quantities of fuel gas would need to be tracked. | Controlled |
| P4 Venting[12] | Venting is a common means of disposing of waste gas at oil and gas facilities and is defined as emissions to the atmosphere by design or operational practice, commonly from gas operated | Controlled |

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[11] CAPP. (2005). *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 5, Compendium of Terminology, Data Sources, etc.*

[12] CAPP. (2005). *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 5, Compendium of Terminology, Data Sources, etc.*

| 1. SS | 2. Description | 3. Controlled, Related or Affected |
|---|---|---|
| | devices. Venting may occur either continuously or intermittently. The quantity of gas vented would need to be tracked.<br>Reported venting includes the sum of all vented volumes stated in production accounting records and includes casing gas venting, waste associated gas flows, treater and stabilizer off-gas and gas volumes released during upset, depressurization or emergency events.<br>Unreported Venting is defined as venting from processes or equipment that is not typically reported in production accounting data. Sources may include glycol dehydrator off-gas, loading/unloading losses, storage losses, pneumatic devices, etc. Note that emissions of vent gases will be accounted for under the SS P5 Fugitive Losses. | |
| P5 Fugitive Losses | Fugitive emissions will occur from equipment used at the project site. Sources of fugitive losses may include leaking fittings / seals, instrument venting, glycol dehydrators, vapour from oil batteries, non routine venting from equipment failure or pressure release and plant tank venting. The quantity and composition of fugitive emissions would need to be tracked. | Controlled |
| P6a Oil and / or Gas Transmission | Oil, natural gas, coal bed methane and/or other petroleum products may be produced as a result of the project. The quantity of fossil fuels produced and transported for processing would need to be tracked. | |
| P7 Facility Operation | Typical facilities could include oil and / or gas production, processing, dehydration and transmission or other upstream oil and gas operations. The operations of the facility at the project site may require the combustion of fossil fuels, precipitating greenhouse gas emissions. Volumes and types of fuels are the important characteristics to be tracked. | Controlled |
| **Downstream SSs during Project Operation** | | |
| P6b Oil and / or Gas Distribution and Usage | Oil, natural gas, coal bed methane and/or other petroleum products may be produced as a result of the project. The quantity of fossil fuels distributed to end users would need to be tracked. | Related |
| **Other** | | |
| P11 Site Development | The site may need to be developed. This could include civil infrastructure such as access to electricity, gas and water supply, as well as sewer etc. This may also include clearing, grading, building access roads, etc. There will also need to be some building of structures for the facility such as storage areas, storm water drainage, offices, vent stacks, firefighting water storage lagoons, etc., as well as structures to enclose, support and house the equipment. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to develop the site such as graders, backhoes, trenching machines, etc. | Related |
| P12 Building Equipment | Equipment may need to be built either on-site or off-site. This includes all of the components of the storage, handling, processing, combustion, air quality control, system control and safety systems. These may be sourced as pre-made standard equipment or custom built to specification. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity | Related |

| 1. SS | 2. Description | 3. Controlled, Related or Affected |
|---|---|---|
| | used to power equipment for the extraction of the raw materials, processing, fabricating and assembly. | |
| P13 Equipment Transportation | Equipment built off-site and the materials to build equipment on-site, will all need to be delivered to the site. Transportation may be completed by train, truck, by some combination, or even by courier. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels to power the equipment delivering the equipment to the site. | Related |
| P14 Site Construction | The process of construction at the site will require a variety of heavy equipment, smaller power tools, cranes and generators. The operation of this equipment will have associated greenhouse gas emission from the use of fossil fuels and electricity. | Related |
| P15 Equipment Testing | Equipment may need to be tested to ensure that it is operational. This may result in running the equipment using test fuels or fossil fuels in order to ensure that the equipment runs properly. These activities will result in greenhouse gas emissions associated with the combustion of fossil fuels and the use of electricity. | Related |
| P16 Site Decommissioning | Once the facility is no longer operational, the site may need to be decommissioned. This may involve the disassembly of the equipment, demolition of on-site structures, disposal of some materials, environmental restoration, re-grading, planting or seeding, and transportation of materials off-site. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to decommission the site. | Related |

## 2.2 Identification of Baseline

### 2.2.1 Identification and Assessment of Possible Baseline Scenarios

An assessment of potential baseline scenarios was conducted based on the recommended methodology from best practice guidance in the Alberta Offset Credit Project Guidance Document. Each baseline scenario contemplated the selection of a static or dynamic approach or both. **TABLE 2.2** provides a summary of the baselines considered.

**TABLE 2.2 Assessment of Possible Baseline Scenarios**

| Baseline Options | Description | Static/ Dynamic | Accept or Reject and Justify |
|---|---|---|---|
| Historic Benchmark | Assessment of baseline emissions from a given facility based on measuring the facility's emissions prior to project implementation. Note that the historic benchmark baseline may be based on data from one month up to three years of monitoring. | Static | Reject. Historic data is not readily available for the majority of facilities. Further, given the potential variability of methane emissions over time, a partial monitoring period of one to three months would not result in an accurate estimate of baseline emissions.<br>In contrast, a longer baseline monitoring period (i.e. one to three years) may result in project developers putting off repairing methane leaks as a means to achieve a higher baseline emissions intensity and would not be feasible given the costs associated with monitoring.<br>Note that where facility historic information exists, it may be used provided it produces a more conservative estimate of baseline fugitive emissions. |
| Performance Standard | Assessment of the typical fugitive methane emissions from a given type of oil and gas facility as compared to the typical emissions profile for the industry/sector. | Static | Accept. This approach use a quantification approach and emission factors that were developed based on industry data, with emissions from a given facility being determined based on the actual equipment and processes used at that facility.<br>This approach is feasible given that it is based on factors developed from real industry data and published best practice guidance, and is based on the best available science. Further, this is the accepted approach for facilities reporting their fugitive emissions under the Alberta SGER regulation and represents industry common practice.<br>An industry standard baseline provides a reasonable representation of the fugitive emissions from the oil and gas industry and is accurate at the aggregate level. |

| Baseline Options | Description | Static/ Dynamic | Accept or Reject and Justify |
|---|---|---|---|
| Comparison Based | Assessment of the baseline fugitive methane emissions from a given oil and gas production site compared to the performance of a control group. | Dynamic | Reject. This approach would be an irresponsible and inaccurate method of quantifying emission reductions. Given the potential variability of methane emissions between sites, this approach would not provide an accurate representation of baseline emissions. |
| Project Based | Assessment of the baseline fugitive methane emissions from an oil and gas production or transmission facility using a model to project an increase or decrease in fugitive emissions into the future. | Dynamic | Reject. Given their unpredictable behaviour, there are no models available to accurately predict changes in the fugitive emissions of an oil and gas facility, nor would there conceivably be a model able to predict the behaviour. |
| Other | Other quantification that may be available through the program authority. | Unknown | Reject. Not Applicable at this time. |

### 2.2.1 Selection of Baseline

As discussed, the baseline condition for projects applying this protocol is defined as the facility's emissions and operating conditions prior to the identification and reduction of planned and / or unplanned fugitive methane emissions. The baseline is project-specific but would be anticipated to include planned and unplanned emissions of methane from venting and fugitive losses at any point in the oil and gas extraction, processing and transportation processes.

The approach to quantifying the baseline will be an industry standard (i.e. performance standard) based on published best practice guidance from the Canadian Association of Petroleum Producers. The baseline scenario for this protocol is static as the volume of methane emissions would be calculated based on the equipment and processes at a given facility prior to project implementation.

Two approaches to calculating an industry standard baseline are identified in the Technical Seed Document associated with this Protocol; the Short-Form Method and the Generic Count Fitting Method. The Short-Form Method estimates fugitive emissions based on the production throughput of a given facility. In contrast, the Generic Fitting Count (GFC) Method uses generic or average fitting counts for specific equipment / processes. Fugitive emissions are then calculated based on the number of fittings, without the need to count fittings at a specific site. This method provides a more accurate estimation of fugitive emissions than the Short-Form Method. This approach is also specific to the type of facility, and provides average fitting counts for light oil, heavy oil, gas production, and gas plants. Emission factors are also delineated based on whether the facility is a gas or oil facility, and whether it is in sweet or sour gas service.

Given that the GFC Method is more accurate and based on the specific facility type and equipment / processes at a facility rather than throughput, this approach is used to define the baseline condition for a given facility. The generic fitting counts to be used are presented in the CAPP Guide: *Calculating Greenhouse Gas Emissions* (CAPP, April 2003) and project developers are referred to that document for details of the calculation. For gas transmission, storage and distribution facilities, the corresponding Average Emission Factors Method, equipment counts and emission factors included in the Canadian Energy Parternership for Environmental Innovation (CEPEI) *Methodology Manual for the Estimation of Air Emission from the Canadian Natural Gas Transmission, Storage and Distribution System* (September, 2007) should be used. Alternatively, where facility historic component counts exist, they may be used provided they produce a more conservative estimate of baseline fugitive emissions.

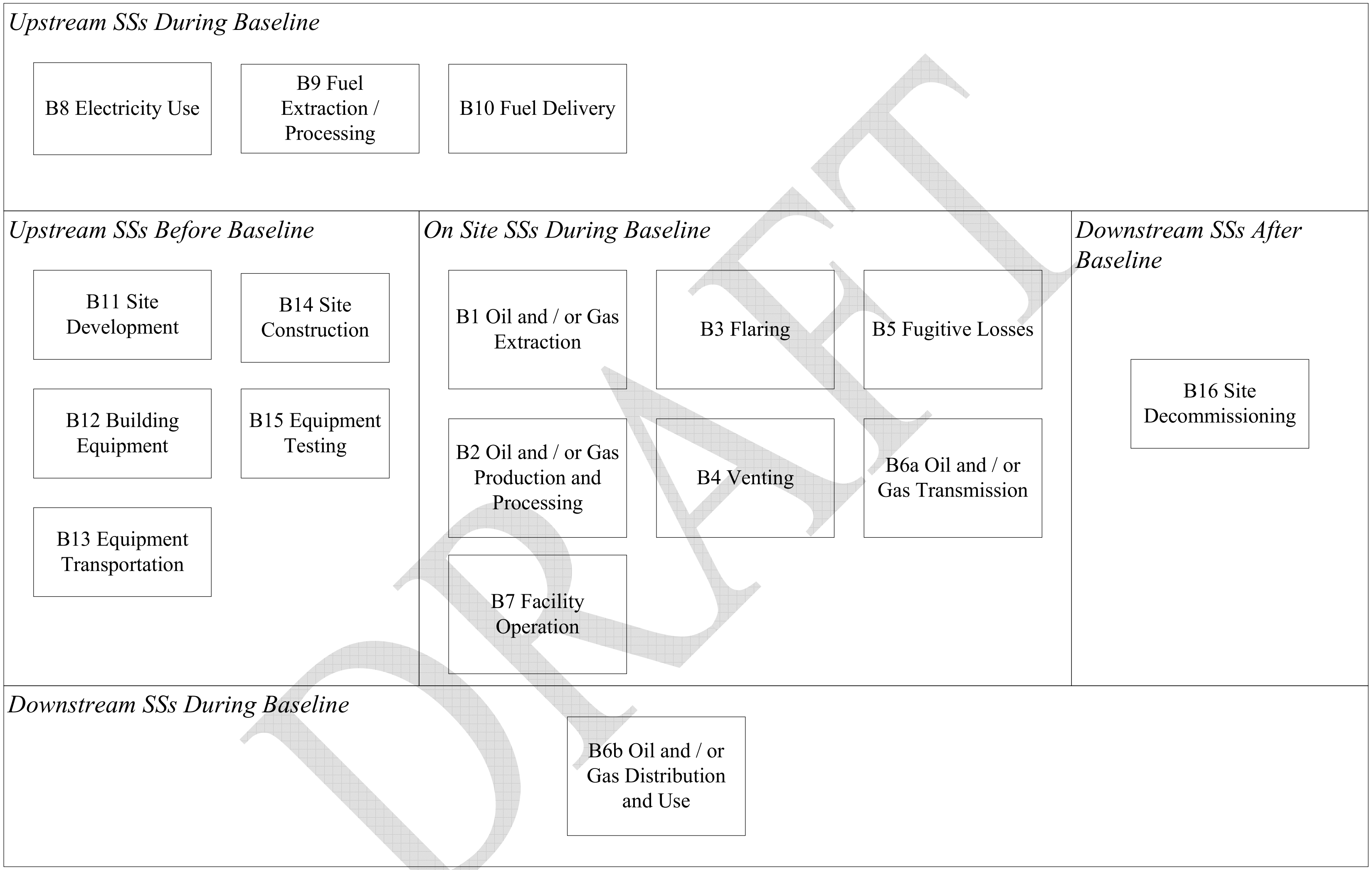
Note that baseline emissions may need to be reviewed following any significant structural or process changes at the facility that would have occurred in the absence of project implementation. These may include activities such as equipment decommissioning and installation of new equipment that would have been conducted under business as usual activities (i.e. old equipment being switched out), process adjustments to account for changes in facility throughput, source gas composition, etc., in-sourcing or outsourcing of operations, purchase or sale of significant emission sources, etc. If evaluation indicates that the change is material (i.e. greater than 5% of base year emissions) and would have occurred in the absence of the project, the baseline emission intensity should be modified to reflect these changes. Justification must be provided by the project proponent to explain any changes to the facility’s baseline emissions.

The baseline condition is defined, including the relevant SSs and processes, as shown in **FIGURE 1.2**. More detail on each of these SSs is provided in Section 2.3, below.

## 2.3 Identification of SSs for the Baseline

Based on the process flow diagrams provided in **FIGURE 1.2**, the project SSs were organized into life cycle categories in **FIGURE 2.2**. Descriptions of each of the SSs and their classification as either ‘controlled’, ‘related’ or ‘affected’ is provided in **TABLE 2.3.**

**FIGURE 2.2: Baseline Element Life Cycle Chart**



## TABLE 2.3: Baseline SSs

| 1. SS | 2. Description | 3. Controlled, Related or Affected |
|---|---|---|
| **Upstream SSs during Baseline Operation** | | |
| B8 Electricity Usage | Electricity may be required to power equipment throughout the extraction, processing and transport processes. The quantity of power consumed and the source of electricity would need to be tracked. | Related |
| B9 Fuel Extraction and Processing | Each of the fuels used throughout the baseline condition may need to sourced and processed. This will allow for the calculation of the greenhouse gas emissions from the various processes involved in the production, refinement and storage of the fuels. The total volumes of fuel for each of the SSs are considered under this SS. Volumes and types of fuels are the important characteristics to be tracked. | Related |
| B10 Fuel Delivery | Each of the fuels used throughout the baseline condition may need to be transported to the site. This may include shipments by tanker or by pipeline, resulting in the emissions of greenhouse gases. It is reasonable to exclude fuel sourced by taking equipment to an existing commercial fuelling station as the fuel used to take the equipment to the sites is captured under other SSs and there is no other delivery. | Related |
| **Onsite SSs during Project Operation** | | |
| B1 Oil and / or Gas Extraction | The extraction of oil and gas can be accomplished using various equipment and processes requiring fuel and electricity inputs. The emissions resulting from these inputs are captured under this SS. The quantity of power, fuel volume and fuel types would be tracked to determine equivalence with the project condition. | Related |
| B2 Oil and / or Gas Production and Processing | Operation of the oil/gas facility may require the use of mechanical equipment, pumps and pressure equipment. This may require several energy inputs such as electricity, natural gas and diesel. Quantities and types for each of the energy inputs would be tracked. | Controlled |
| B3 Flaring[13] | Flaring is a common means of disposing of waste gas at oil and gas facilities. Flaring is normally used at sour gas facilities where waste gas contains toxic components and for both high and low pressure waste gas streams. From time to time gas may be flared at the baseline site as a result of emergency shut-down, maintenance or other operational conditions. Emissions of greenhouse gases would be contributed from the combustion of the gases as well as from any fuel gas used in flaring to ensure more complete combustion. Quantities of gas being flared and the quantities of fuel gas would need to be tracked. | Controlled |
| B4 Venting[14] | Venting is a common means of disposing of waste gas at oil and gas facilities and is defined as | Controlled |

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[13] CAPP. (2005). *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 5, Compendium of Terminology, Data Sources, etc.*

[14] CAPP. (2005). *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 5, Compendium of Terminology, Data Sources, etc.*

| 1. SS | 2. Description | 3. Controlled, Related or Affected |
|---|---|---|
| | emissions to the atmosphere by design or operational practice, commonly from gas operated devices. Venting may occur either continuously or intermittently. The quantity of gas vented would need to be tracked.<br>Reported venting includes the sum of all vented volumes stated in production accounting records and includes casing gas venting, waste associated gas flows, treater and stabilizer off-gas and gas volumes released during upset, depressurization or emergency events.<br>Unreported Venting is defined as venting from processes or equipment that is not typically reported in production accounting data. Sources may include glycol dehydrator off-gas, loading/unloading losses, storage losses, pneumatic devices, etc.<br>Note that emissions of vent gases will be accounted for under the SS B5 Fugitive Losses. | |
| B5 Fugitive Equipment Leaks | Fugitive emissions will occur from equipment used at the project site. Sources of fugitive losses may include leaking fittings / seals, instrument venting, glycol dehydrators, vapour from oil batteries, non routine venting from equipment failure or pressure release and plant tank venting. The quantity and composition of fugitive emissions would need to be tracked. | Controlled |
| B6a Oil and / or Gas Transmission | Oil, natural gas, coal bed methane or other petroleum products would have to be produced to offset the additional production that which may occur under the project condition. The quantity of products produced and transported for processing would need to be tracked. | |
| B7 Facility Operation | Typical facilities could include oil and / or gas production, processing, dehydration and transmission or other upstream oil and gas operations. The operations of the facility at the project site may require the combustion of fossil fuels, precipitating greenhouse gas emissions. Volumes and types of fuels are the important characteristics to be tracked. | Controlled |
| **Downstream SSs during Project Operation** | | |
| B6b Oil and / or Gas Distribution and Usage | Oil, natural gas, coal bed methane and/or other petroleum products may be produced as a result of the project. The quantity of fossil fuels distributed to end users would need to be tracked. | Related |
| **Other** | | |
| B11 Site Development | The site may need to be developed. This could include civil infrastructure such as access to electricity, gas and water supply, as well as sewer etc. This may also include clearing, grading, building access roads, etc. There will also need to be some building of structures for the facility such as storage areas, storm water drainage, offices, vent stacks, firefighting water storage lagoons, etc., as well as structures to enclose, support and house the equipment. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to develop the site such as graders, backhoes, trenching machines, etc. | Related |

| **1. SS** | **2. Description** | **3. Controlled, Related or Affected** |
|---|---|---|
| B12 Building Equipment | Equipment may need to be built either on-site or off-site. This includes all of the components of the storage, handling, processing, combustion, air quality control, system control and safety systems. These may be sourced as pre-made standard equipment or custom built to specification. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment for the extraction of the raw materials, processing, fabricating and assembly. | Related |
| B13 Equipment Transportation | Equipment built off-site and the materials to build equipment on-site, will all need to be delivered to the site. Transportation may be completed by train, truck, by some combination, or even by courier. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels to power the equipment delivering the equipment to the site. | Related |
| B14 Site Construction | The process of construction at the site will require a variety of heavy equipment, smaller power tools, cranes and generators. The operation of this equipment will have associated greenhouse gas emission from the use of fossil fuels and electricity. | Related |
| B15 Equipment Testing | Equipment may need to be tested to ensure that it is operational. This may result in running the equipment using test fuels or fossil fuels in order to ensure that the equipment runs properly. These activities will result in greenhouse gas emissions associated with the combustion of fossil fuels and the use of electricity. | Related |
| B16 Site Decommissioning | Once the facility is no longer operational, the site may need to be decommissioned. This may involve the disassembly of the equipment, demolition of on-site structures, disposal of some materials, environmental restoration, re-grading, planting or seeding, and transportation of materials off-site. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to decommission the site. | Related |

## 2.4 Selection of Relevant Project and Baseline SSs

Each of the SSs from the project and baseline condition were compared and evaluated as to their relevancy using the guidance provided in Annex VI of the "Guide to Quantification Methodologies and Protocols: Draft", dated March 2006 (Environment Canada). The justification for the exclusion or conditions upon which SSs may be excluded is provided in **TABLE 2.4** below. All other SSs listed previously are included.

## TABLE 2.4: Comparison of SSs

| 1. Identified SS | 2. Baseline (C, R, A) | 3. Project (C, R, A) | 4. Include or Exclude from Quantification | 5. Justification for Exclusion |
|---|---|---|---|---|
| **Upstream SSs** | | | | |
| P8 Electricity Use | N/A | Related | Exclude | Excluded as these SSs are not relevant to the project and the emissions from these practises are covered under proposed greenhouse gas regulations. |
| B8 Electricity Use | Related | N/A | Exclude | |
| P9 Fuel Extraction and Processing | N/A | Related | Exclude | Excluded as this protocol is applicable to oil and gas production and processing facilities. These emissions are thereby accounted for in the other project and baseline SS's and including them would result in double counting. |
| B9 Fuel Extraction and Processing | Related | N/A | Exclude | |
| P10 Fuel Delivery | N/A | Related | Exclude | Excluded as the emissions from transportation of fuel do not change between the project and baseline conditions. |
| B10 Fuel Delivery | Related | N/A | Exclude | |
| **Onsite SSs** | | | | |
| P1 Oil and / or Gas Extraction | N/A | Related | Exclude | Excluded as the activity of oil and gas extraction is equivalent in the project and baseline conditions. The emissions associated with these activities will not change as a result of project implementation, therefore this SS is not relevant for quantification. |
| B1 Oil and / or Gas Extraction | Related | N/A | Exclude | |
| P2 Oil and / or Gas Production and Processing | N/A | Controlled | Exclude | Excluded as the activity of oil and gas production and processing is equivalent in the project and baseline conditions. The emissions associated with these activities will not change as a result of project implementation, therefore this SS is not relevant for quantification. |
| B2 Oil and / or Gas Production and Processing | Controlled | N/A | Exclude | |
| P3 Flaring | N/A | Controlled | Include | N/A (This SS may be excluded at facilities that sell methane as a final product, since methane would not be flared. At facilities that do not sell methane (i.e. gas facilities) flaring may be the only option and this SS is included). |
| B3 Flaring | Controlled | N/A | Exclude | Excluded as the methane emissions associated with flaring will be negligible, and are not expected to change materially as a result of project implementation. |
| P4 Venting | N/A | Controlled | Exclude | Excluded as the methane emissions from venting are included in the quantification of the SS P5 Fugitive Losses. |
| B4 Venting | Controlled | N/A | Exclude | Excluded as the methane emissions from venting are included in the quantification of the SS B5 Fugitive Losses. |
| P5 Fugitive Losses | N/A | Controlled | Include | N/A |
| B5 Fugitive Losses | Controlled | N/A | Include | N/A |

| 1. Identified SS | 2. Baseline (C, R, A) | 3. Project (C, R, A) | 4. Include or Exclude from Quantification | 5. Justification for Exclusion |
|---|---|---|---|---|
| P6b Oil and / or Gas Transmission | N/A | Related | Exclude | Excluded as these SSs are likely equivalent under the project and baseline conditions. |
| B6b Oil and / or Gas Transmission | Related | N/A | Exclude | |
| P7 Facility Operation | N/A | Controlled | Exclude | Excluded as the emissions from facility operation will either not be impacted by project implementation or decreased if captured methane is used as a fuel source on-site. Further, fuel consumption may vary as a function of seasonal variations, changes in the composition of gas processed at the facility and other factors that would not be reflected in the baseline or impacted by the project. This SS is therefore not relevant for quantification. |
| B7 Facility Operation | Controlled | N/A | Exclude | |
| **Downstream SSs** | | | | |
| P6a Oil and / or Gas Distribution and Use | N/A | Related | Exclude | Excluded as these SSs are likely equivalent under the project and baseline conditions. |
| B6a Oil and / or Gas Distribution and Use | Related | N/A | Exclude | |
| **Other** | | | | |
| P11 Site Development | N/A | Related | Exclude | Emissions from site development are not material given the long project life, and the minimal site development typically required. |
| B11 Site Development | Related | N/A | Exclude | |
| P12 Building Equipment | N/A | Related | Exclude | Emissions from building equipment are not material given the long project life, and the minimal building equipment typically required. |
| B12 Building Equipment | Related | N/A | Exclude | |
| P13 Equipment Transportation | N/A | Related | Exclude | Emissions from transportation of equipment are not material given the long project life, and the minimal transportation of equipment typically required. |
| B13 Equipment Transportation | Related | N/A | Exclude | |
| P14 Site Construction | N/A | Related | Exclude | Emissions from construction on site are not material given the long project life, and the minimal construction on site typically required. |
| B14 Site Construction | Related | N/A | Exclude | |
| P15 Equipment Testing | N/A | Related | Exclude | Emissions from testing of equipment are not material given the long project life, and the minimal testing of equipment typically required. |
| B15 Equipment Testing | Related | N/A | Exclude | |
| P16 Site Decommissioning | N/A | Related | Exclude | Emissions from decommissioning are not material given the long project life, and the minimal decommissioning typically |

| 1. Identified SS | 2. Baseline (C, R, A) | 3. Project (C, R, A) | 4. Include or Exclude from Quantification | 5. Justification for Exclusion |
|---|---|---|---|---|
| B16 Site Decommissioning | Related | N/A | Exclude | required. |

## 2.5 Quantification of Reductions, Removals and Reversals of Relevant SS

### 2.5.1 Quantification Approaches

Quantification of the reductions, removals and reversals of relevant SSs for each of the greenhouse gases will be completed using the methodologies outlined in **TABLE 2.5**, below. These calculation methodologies serve to complete the following three equations for calculating the emission reductions from the comparison of the baseline and project conditions.

$$\text{Emission Reduction} = (\text{Emissions}_{\text{Baseline}} - \text{Emissions}_{\text{Project}}) * (1 - \text{Improvement Factor})$$

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{Methane (Baseline)}}$$

$$\text{Emissions}_{\text{Project}} = \text{Emissions}_{\text{Flaring}} + \text{Emissions}_{\text{Methane (Project)}}$$

Where:

$\text{Emissions}_{\text{Baseline}}$ = sum of the emissions under the baseline condition

$\text{Emissions}_{\text{Methane (Baseline)}}$ = emissions under SS B4 Venting and SS B5 Fugitive Losses

$\text{Emissions}_{\text{Project}}$ = sum of the emissions under the project condition

$\text{Emissions}_{\text{Flaring}}$ = emissions under SS P3 Flaring

$\text{Emissions}_{\text{Methane (Project)}}$ = emissions under SS P4 Venting and SS P5 Fugitive Losses

Improvement Factor = This factor represents the anticipated percentage decrease in the volume of fugitive methane emissions from all upstream oil and gas sources, as a result of the implementation of a Direct Inspection and Maintenance Leak Detection and Repair Program that is in compliance with ERCB Directive 060.

The value of this factor is included in Alberta Environment Reference Documents and will be adjusted as appropriate by Alberta Environment. ***NOTE: the value of this factor is currently under development. Once finalized, further detail will be provided in Alberta Environment Reference Documents.***

## TABLE 2.5: Quantification Procedures

| 1.0 Project/ Baseline SS | 2. Parameter / Variable | 3. Unit | 4. Measured / Estimated | 5. Method | 6. Frequency | 7. Justify measurement or estimation and frequency |
|---|---|---|---|---|---|---|
| **Project SSs** | | | | | | |
| P3 Flaring | $\text{Emissions}_{\text{Flaring}} = (\text{Emissions}_{\text{Methane (Baseline)}} - \text{Emissions}_{\text{Methane (Project)}}) * (1 - \text{Eff}) * \text{GWP}_{CH4}$;<br>$([(\text{Emissions}_{\text{Methane (Baseline)}} - \text{Emissions}_{\text{Methane (Project)}}) * \text{Eff} * \text{EF}_{CO2}] / \rho\ CH_4)$;<br>$([(\text{Emissions}_{\text{Methane (Baseline)}} - \text{Emissions}_{\text{Methane (Project)}}) * \text{Eff} * \text{EF}_{N2O}] / \rho\ CH_4)$; | | | | | |
| | $\text{Emissions}_{\text{Flaring}}$ | kg of $CO_{2E}$ | N/A | N/A | N/A | Quantity being calculated. This equation assumes that any methane that was released in the baseline condition but conserved in the project condition at facilities that do not sell methane as a final product is flared. Note that in practice this may not be the case, but it is conservative to assume that conserved gas is flared and emitted as $CO_2$. The project proponent also has the option of demonstrating that methane is not flared.<br>This equation assumes that no supplemental fuel gas (i.e.natural gas or sales gas that is added to the gas stream to be flared) is required to meet ERCB heating value requirements.<br>$N_2O$ emissions are calculated using industrial emission factors for natural gas as this provides a conservative estimate of the emissions from flaring the captured methane gas stream. |
| | Total Baseline Methane Emissions / $\text{Emissions}_{\text{Methane (Baseline)}}$ | kg $CH_4$ | N/A | Quantity calculated under SS B5 | Monthly | The quantity of baseline methane emissions calculated for the SS B5. The difference between project and baseline emissions from the SS's B5 and P5 represents the quantity of methane conserved in the project condition. |
| | Total Project Methane Emissions / $\text{Emissions}_{\text{Methane (Baseline)}}$ | kg $CH_4$ | N/A | Quantity calculated under SS P5 | Monthly | The quantity of baseline methane emissions calculated for the SS P5. The difference between project and baseline emissions from the SS's B5 and P5 represents the quantity of methane conserved in the project condition. |
| | Flare Efficiency / Eff | % | Estimated | From the Canadian Association of Petroleum Producers | Annual | Reference values adjusted periodically. |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | (CAPP) reference documents flare efficiency is 98%. This value is in accordance with current regulations in Alberta ERCB Directive 060. | | |
| | Density of Methane / ρ CH4 | kg / $m^3$ | Constant | 0.717 kg/$m^3$ at standard temperature and pressure (STP). | Reference Value | Density should be corrected if actual temperatures and pressures of the gas stream are not consistent with reference values. |
| | $EF_{CO2}$ | kg $CO_2$ / $m^3$ methane | Estimated | From Environment Canada / the Canadian Association of Petroleum Producers (CAPP) (Appendix B). | N/A | Emission factors for natural gas are used to estimate the $CO_2$ emissions from combusting the methane gas stream. This approach is consistent with the Alberta Quantification Protocol for Landfill Gas Capture and Combustion.<br>Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory. |
| | $EF_{N2O}$ | kg $N_2O$ / $m^3$ methane | Estimated | From Environment Canada / the Canadian Association of Petroleum Producers (Appendix B). | Annual | Emission factors for natural gas are used to estimate the $N_2O$ emissions from combusting the methane gas stream. This approach is consistent with the Alberta Quantification Protocol for Landfill Gas Capture and Combustion.<br>Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory. |
| P4 Venting<br>P5 Fugitive Losses | $\text{Emissions}_{\text{Methane (Project)}} = \sum(\text{Measured Leak Vol.}_{\text{Methane}} * \rho_{CH4} * GWP_{CH4})$ | | | | | |
| | Emissions Methane (Project) | kg of $CO_{2E}$ | N/A | N/A | N/A | Quantity being calculated. Project emissions will be measured and monitored virtually continuously using an applicable technology as outlined in Appendix A.<br>Note that this quantity must also be calculated following the approach outlined in Appendix C for large unplanned emission sources, following repair. This information is required by AENV for comparison with the emission reductions quantified using the industry standard baseline approach used in this protocol. |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Measured Volume of Methane Emissions / Measured Leak Vol. $_{\text{Methane}}$ | $m^3$ | Measured | Direct measurement of volume of methane emitted, converted to STP conditions. | Virtually continuous monitoring using one of the technologies listed in Appendix A, or another similar technology. Quarterly reconciliation of measured data. | Direct measurement, complete site coverage and virtually continuous monitoring represent industry best practice. Frequency of measurement is highest level possible. |
| | Density of $CH_4$ / $\rho_{CH4}$ | kg / $m^3$ | Constant | 717 kg/$m^3$ at standard temperature and pressure (STP). | Reference Value | N/A |
| **Baseline SSs** | | | | | | |
| | $\text{Emissions}_{\text{Methane (Baseline)}} = \sum (N_i * F_i * \% \text{ Mass } CH_4 * \text{Project Hrs} * GWP_{CH4})$ | | | | | |
| B4 Venting<br>B5 Fugitive Losses | Emissions $_{\text{Methane (Baseline)}}$ | kg of $CO_{2E}$ | N/A | N/A | N/A | Quantity being calculated.<br>Note that this quantity must also be calculated following the approach outlined in Appendix C for large unplanned emission sources, prior to repair. This information is required by AENV for comparison with the emission reductions quantified using the industry standard baseline approach used in this protocol. |
| | Number of Fittings of Type i / $N_i$ | - | Estimated | From the Canadian Association of Petroleum Producers (CAPP) and the Canadian Energy Parternership for Environmental Innovation (CEPEI) (Appendix B). | Annual | Generic or average connector counts by equipment / process type are delineated for light oil, heavy oil, gas production, gas plants and offshore platforms. Factors are also available for gas transmission facilities.<br>Reference values adjusted periodically as part of CAPP's / CEPEI's reporting of emissions from the oil and gas industry. |
| | Fugitive Emission Factor for | kg/hr/ fitting | Estimated | From the Canadian Association of Petroleum Producers | Annual | Emissions factors for fugitive emission sources in vapour service are delineated by fitting type for oil and gas facilities. |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Fitting Type i / $F_i$ | | | (CAPP) and the Canadian Energy Parternership for Environmental Innovation (CEPEI) (Appendix B). | | Reference values adjusted periodically as part of CAPP's / CEPEI's reporting of emissions from the oil and gas industry. |
| | Weight Fraction of $CH_4$ in Gas Stream / % Mass $CH_4$ | - | Calculated | N/A | N/A | Quantity being calculated. |
| | % Mass $CH_4$ = (% Vol. CH4 * $MW_{CH4}$) / $MW_{Gas}$ | | | | | |
| | Volumetric Fraction of $CH_4$ in Gas Stream / % Vol. $CH_4$ | - | Measured | Direct measurement | Quarterly sampling. | Composition may vary throughout the project. Quarterly gas composition measurement is reasonable for facility operation and this frequency of sampling provides for reasonable diligence. |
| | Molecular Weight of $CH_4$ / $MW_{CH4}$ | g/mol | Constant | 16.04 g/mol | N/A | Accepted value. |
| | Molecular Weight of Mixed Gas Stream / $MW_{Gas}$ | g/mol | Measured | Direct measurement | Quarterly sampling. | Composition may vary throughout the project. Quarterly gas composition measurement is reasonable for facility operation and this frequency of sampling provides for reasonable diligence. |
| | Number of Hours in Project Monitoring Period / Project Hrs | hrs | Measured | Measurement of the number of hours over which the volume of methane is measured in the project monitoring period. | Monthly | This parameter will be used to quantify the monthly methane emissions from the facility. Depending on the frequency of reconciliation of data, the duration of the project monitoring period may be up to three months. |
| Multiple Project and Baseline SSs | Global Warming Potential of Methane / $GWP_{CH4}$ | kg $CO_{2E}$ / kg $CH_4$ | Estimated | From Environment Canada; IPCC. | Annual | The applicable global warming potential of $CH_4$ is 21, as per the Intergovernmental Panel on Climate Change. *Climate Change 1995: The Science of Climate Change* (Cambridge, UK: Cambridge University Press, 1996). This value should be used for all calculations, to maintain consistency with internationally accepted best practice guidance. |

### 2.5.2 Contingent Data Approaches

Contingent means for calculating or estimating the required data for the equations outlined in Section 2.5.1 are summarized in **TABLE 2.6**, below.

## 2.6 Management of Data Quality

In general, data quality management must include sufficient data capture such that the mass and energy balances may be easily performed with the need for minimal assumptions and use of contingency procedures. The data should be of sufficient quality to fulfill the quantification requirements and be substantiated by company records for the purpose of verification.

The project proponent shall establish and apply quality management procedures to manage data and information. Written procedures should be established for each measurement task outlining responsibility, timing and record location requirements. The greater the rigour of the management system for the data, the more easily an audit will be to conduct for the project.

### 2.6.1 Record Keeping

Record keeping practises should include:

a. Electronic recording of values of logged primary parameters for each measurement interval;
b. Printing of monthly back-up hard copies of all logged data;
c. Written logs of operations and maintenance of the project system including notation of all shut-downs, start-ups and process adjustments;
d. Retention of copies of logs and all logged data for a period of seven years; and
e. Keeping all records available for review by a verification body.

### 2.6.2 Quality Assurance/Quality Control (QA/QC)

QA/QC should be applied to the changes made at the facility resulting in reduced methane emissions. These include, but are not limited to:

a. Recording all significant changes made at the facility that may reduce fugitive methane emissions including process changes, installation of new equipment, implementation of different practices at the facility, equipment operation and maintenance activities, repairs, etc.; and
b. Listing of each change with as much detail as possible including date, location, cost, estimated emission reduction, etc.

QA/QC may need to be applied to the remote sensing technology depending on the technology selected to quantify facility methane emissions. These may include, but are not limited to[15]:

a. Calibration and checking of equipment according to manufacturer specifications;
b. Collection of sample that is representative in terms of time, location and conditions;
c. Collection of detailed meteorology observations concurrent with air measurements;
d. Period checks to ensure there is no interference from other nearby sources;
e. Review of air monitoring instrumentation to ensure detection limits are appropriate and equipment is rated to operate in cold weather;
f. Testing of equipment during precipitation or fog to ensure instrument performance is adequate; and
g. Collection of additional measurements and data for non-homogeneous sources. This will include the use of tracer to pollutant ratio testing to calibrate the dispersion model.

QA/QC can also be applied to add confidence that all measurements and calculations have been made correctly. These include, but are not limited to:

a Protecting monitoring equipment (sealed meters and data loggers);
b Protecting records of monitored data (hard copy and electronic storage);
c Checking data integrity on a regular and periodic basis (manual assessment, comparing redundant metered data, and detection of outstanding data/records);
d Comparing current estimates with previous estimates as a ‘reality check’;
e Provide sufficient training to operators to perform maintenance and calibration of monitoring devices;
f Establish minimum experience and requirements for operators in charge of project and monitoring; and
g Performing recalculations to make sure no mathematical errors have been made.

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[15] CAPP. (1999). $CH_4$ and VOC Emissions from the Canadian Upstream Oil and Gas Industry – Volume 4

## TABLE 2.6: Contingent Data Collection Procedures

| 1. Project/ Baseline SS | 2. Parameter / Variable | 3. Unit | 4. Measured / Estimated | 5. Method | 6. Frequency | 7. Justify measurement or estimation and frequency |
|---|---|---|---|---|---|---|
| **Project SSs** | | | | | | |
| P3 Flaring | Total Baseline Methane Emissions / $Emissions_{Methane\ (Baseline)}$ | None | | | | |
| | Total Project Methane Emissions / $Emissions_{Methane\ (Baseline)}$ | None | | | | |
| P4 Venting<br>P5 Fugitive Losses | Measured Volume of Methane Emissions / Measured Leak $Vol._{Methane}$ | None | | | | |
| **Baseline SSs** | | | | | | |
| B4 Venting<br>B5 Fugitive Losses | Volumetric fraction of $CH_4$ in Gas Stream / % Vol. $CH_4$ | % | Estimated | Interpolation of previous and following measurements taken. | Quarterly | Interpolating gas composition provides a reasonable estimate when the more accurate and precise method cannot be used. |
| | Molecular Weight of Mixed Gas Stream / $MW_{Gas}$ | g/mol | Estimated | Interpolation of previous and following measurements taken. | Quarterly | Interpolating gas composition provides a reasonable estimate when the more accurate and precise method cannot be used. |
| | Number of Hours in Project Monitoring Period / Project Hrs | None | | | | |

# Appendix A
# Methods of Direct Measurement of Methane Emissions

Remote monitoring systems sensitive to methane may be used to quantify the methane emissions at a given facility using this protocol. Remote monitoring systems may employ either point or path-integrated sampling[16]. A range of point source and path-integrated methods of measurement of fugitive emissions were considered as summarized in the Technical Seed Document that accompanies this protocol.

According to the Technical Seed Document, traditional point source measurement techniques do not provide complete and continuous coverage of the site. As such, these technologies are not appropriate. **TABLE A.1** contains a summary of available technologies. Only those technologies that provide direct quantification, virtually continuous monitoring and complete coverage are eligible.

For further detail on the technologies outlined in **TABLE A.1** refer to the Petroleum Alliance of Canada's *Review and Update of Methods for Air Emissions Leak Detection and Quantification*. This document is available at: http://www.ptac.org/eet/dl/eetp0701.pdf.

The technology selected should be calibrated and checked at the site as required by manufacturer specifications to ensure accuracy.

**Table A.1 Summary of Available Technologies**

| Technology | Direct Quantification | Virtually Continuous | Complete Coverage |
|---|---|---|---|
| **7.0 POINT SOURCE LEAK DETECTION AND CONCENTRATION MEASUREMENT METHODS.** | | | |
| 7.1 CLOSE RANGE DETECTION AND MEASUREMENT METHODS. | | | |
| 7.1.1 Flame Ionization Detection (FID). | Yes (in combination) | No | No |
| 7.1.2 Photoionization Detection (PID). | Yes (in combination) | No | No |
| 7.1.3 Catalytic Combustion (CC). | Yes (in combination) | No | No |
| 7.1.4 Thermal Conductivity (TC). | Yes (in combination) | No | No |
| 7.1.5 Solid State (SS). | Yes (in combination) | No | No |
| 7.1.6 Infrared Absorption (IR). | Yes (in combination) | No | No |
| 7.1.7 Tunable Diode Laser Absorption Spectroscopy (TDLAS). | Yes (in combination) | No | No |
| 7.1.8 Bubble Tests. | No | No | No |
| 7.1.9 Acoustic Leak Detection. | No | No | No |
| 7.2 REMOTE SENSING METHODS. | | | |
| 7.2.1 Passive IR Gas Imaging. | No | No | No |
| 7.2.1.1 Thermal Imaging. | No | No | No |
| 7.2.1.2 Image Multi – Spectral Sensing (IMSS). | No | No | No |
| 7.2.2 Open Path Gas Detection from Point Sources. | No | No | No |
| 7.2.2.1 Open Path Tunable Diode Laser Absorption Spectroscopy (TDLAS). | No | No | No |
| 7.3 AIRBORNE SENSING METHODS (PIPELINE INSPECTIONS). | | | |
| 7.3.1 Tunable Diode Laser Absorption Spectroscopy (TDLAS). | No | No | No |
| 7.3.2 Airborne Differential Absorption LIDAR (Airborne DIAL). | No | No | No |
| 7.3.3 Gas Filter Correlation Radiometry (GFCR). | No | No | No |
| **8.0 POINT SOURCE QUANTIFICATION METHODS.** | | | |
| 8.1 BAGGING. | Yes | No | No |
| 8.2 HI–FLOW SAMPLER. | Yes | No | No |
| 8.3 ROTAMETERS AND OTHER FLOW METERING DEVICES. | Yes | No | No |
| 8.4 TRACER GAS. | No | No | No |
| **9.0 AREA SOURCE LEAK DETECTION AND QUANTIFICATION TECHNOLOGIES.** | | | |
| 9.1 DIFFERENTIAL ABSORPTION LIDAR (DIAL). | Yes | No | Yes |
| 9.2 AIR DETECTION AND RANGING (AIRDAR). | Yes | Yes | Yes |
| 9.3 OPEN PATH, PATH-INTEGRATED OPTICAL REMOTE SENSING (PI-ORS). | No | Yes | Yes |
| 9.3.1 Open Path Tunable Diode Laser Absorption Spectroscopy (TDLAS). | * Yes | Yes | Yes |
| 9.3.2 Open Path Fourier Transform Infrared (FTIR) Spectroscopy. | No | Yes | Yes |
| 9.3.3 Radial Plume Mapping (RPM). | No | Yes | Yes |

* Recently added quantification capability

* Table 1 from the Technical Seed Document (2008) completed by Keyera, Husky, Shell and Nexen

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[16] CAPP. (1999). $CH_4$ and VOC Emissions from the Canadian Upstream Oil and Gas Industry – Volume 4

The following in-situ methods of quantification meet the requirements for direct, virtually continuous measurement with complete coverage, as outlined in the accompanying Technical Seed Document. Note that other technologies that provide the same level of coverage and / or accuracy in estimates of emissions may also be applied.

Generally, if the emission source is homogeneous the use of remote sensing data is sufficient to accurately model the emission rate. For heterogeneous sources, additional testing and measurement may be required to determine the size, location and emission rate[17]. The project proponent should refer to CAPP's (1999) publication entitled: *$CH_4$ and VOC Emissions from the Canadian Upstream Oil and Gas Industry – Volume 4* for further guidance.

### 1. Air Detection and Ranging (AIRDAR)

This technology is able to measure fugitive methane emissions for the overall facility, as well as the location and characteristics of important leaks[18]. AIRDAR is a proprietary technology that locates and quantifies emission sources based on concentrations of methane and wind measurements taken at various points around a facility. Emission plumes are intercepted with these point observations and characterised with AIRDAR's proprietarily algorithms to provide source locations and strengths. Variations in emission rates over time are also provided. The AIRDAR technology is capable of tracking plumes of very low concentrations and is currently readily available in Alberta.

This method provides an estimate of fugitive source locations and volumes based on direct measurement at specific points, and can provide emission rates over time. The AIRDAR method is accessible to project proponents and could be used to monitor fugitive emissions under the project condition.

### 2. Open-Path Tunable Diode Laser Absorption Spectroscopy (TDLAS)[19]

Tunable Diode Laser Absorption Spectroscopy (TDLAS) is a type of open path gas detection that is used to identify and quantify airborne pollutants. Open path technologies are sensitive to low concentrations and high volumes of hydrocarbons, $CH_4$, $H_2S$ and other gases. PTAC recommends that these technologies always be used in conjunction with point specific gas monitors to accurately assess the volume and concentration of gases.

The TDLAS technology involves the use of a laser diode and infrared absorption spectroscopy to scan the absorption line of a target gas. A photodiode detector measures the

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[17] CAPP. (1999). $CH_4$ and VOC Emissions from the Canadian Upstream Oil and Gas Industry – Volume 4

[18] Petroleum Technology Alliance Canada Technology for Emission Reduction and Eco-Efficiency(TEREE) Steering Committee. (2007). *Review and Update of Methods Used for Air Emissions Leak Detection and Quantification*.

[19] Petroleum Technology Alliance Canada Technology for Emission Reduction and Eco-Efficiency(TEREE) Steering Committee. (2007). *Review and Update of Methods Used for Air Emissions Leak Detection and Quantification*.

fraction of light absorption caused by the target gas molecules between the detector and a target or passive reflector, which is then used to calculate the gas's concentration.

The TDLAS technology is the most interference free method of any analytical method currently available for air emissions monitoring and leak detection and is not affected by water vapour or $CO_2$. The laser light is selective to detecting methane and has a measurement path of up to one kilometre. Further, it has very low detection limits and the system is self calibrating. Note that under heavy dust, steam or fog conditions the TDLAS system may be subject to error.

# Appendix B
# Relevant Emission Factors

## Gas Production and Processing Facility Emission Factors for Calculation of Baseline Emissions following the GFC Method

All values for gas production and processing facilities interpreted from the Guide to Calculating Greenhouse Gas Emissions, dated April 2003 by the Canadian Associated of Petroleum Producers (CAPP).

After the project developer has determined the number of equipment/processes at a given facility, the number of fittings per process (included in **TABLES B.2 to B.6**) may be used to determine the total number of fittings at the facility.

The total fugitive emissions are then calculated as outlined in **TABLE 2.5** of the protocol, using the total fitting count along with the fugitive emission factors listed in **TABLE B.1**. Factors for **TABLE B.1** were taken from "A Detailed Inventory of $CH_4$ and VOC Emissions from Upstream Oil and Gas Operations in Alberta", CAPP, Vol. II, D.J. Picard, March 1992, Table 6, page 75. They can also be found in "A Detailed Inventory of $CH_4$ and VOC Emissions From Upstream Oil and Gas Operations in Canada," Volume II, Table 14, page 79 (by Clearstone Engineering, December 3, 1998).

Note that **TABLE B.6** should be used with caution, because "although the number of PRVs shown per equipment is reasonable, it is unlikely that this number of PRVs will be vented to atmosphere at Canadian facilities. Operations staff should be consulted about how many PRVs actually vent to atmosphere at their facility. Operations staff should also review all allocated generic fitting counts prior to finalizing fugitive emission calculations"[20].

Note also that this approach does not take into account venting from gas operated field instrumentation and controllers and these losses must be determined separately.

Table B.1: Fugitive Emissions Factors in Vapour Service

| Fitting | Gas Facilities (kg/hr/fitting) | Oil Facilities (kg/hr/fitting) |
|---|---|---|
| Valves (sweet gas) | 0.04351 | 0.01417 |
| Valves (sour gas) | 0.00518 | |
| Flanges/Connectors (sweet) | 0.00253 | 0.00079 |
| Flanges/Connectors (sour) | 0.00031 | |
| Compressor seals | 0.80488 | 0.80488 |
| PRVs (vented to atmosphere) | 0.12096 | 0.12096 |
| Open-ended lines | 0.00373 | 0.00373 |

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[20] Canadian Association of Petroleum Producers (CAPP). (2003). *Calculating Greenhouse Gas Emissions*

Table B.2: Generic or Average Connector Counts by Equipment/Process Type

| Equipment/Process | Light Oil Facilities | Heavy Oil Facilities | Gas Production | Gas Plants | Offshore Platforms | Overall Onshore Average |
|---|---|---|---|---|---|---|
| Well | 53 | 44 | 60 | | 195 | 52 |
| Header | 389 | 108 | 105 | 145 | 310 | 187 |
| Heater | 146 | | 147 | | 197 | 147 |
| Separator | 111 | 41 | 160 | 48 | 299 | 90 |
| Filter | | | 122 | | 269 | 122 |
| Chiller | 94 | | | | | 94 |
| Meter | 91 | | 55 | 160 | 383 | 102 |
| Dehydrator | 119 | | 155 | 105 | 210 | 126 |
| Fractionation | | | | 81 | | 81 |
| Sulphur | 109 | | | 144 | | 127 |
| Compressor | 163 | | 195 | 129 | 417 | 162 |
| Vapour Recovery | | | 78 | | 162 | 78 |
| Scrubber | 105 | | 120 | 81 | 177 | 102 |
| Flare | 114 | | | 221 | 376 | 168 |

Table B.3: Generic or Average Valve Counts by Equipment/Process Type

| Equipment/ Process | Light Oil Facilities | Heavy Oil Facilities | Gas Production | Gas Plants | Offshore Platforms | Overall Onshore Average |
|---|---|---|---|---|---|---|
| Well | 13 | 8 | 16 | | 61 | 12 |
| Header | 109 | 17 | 26 | 38 | 82 | 48 |
| Heater | 28 | | 22 | | 45 | 25 |
| Separator | 24 | 10 | 30 | 17 | 81 | 20 |
| Filter | | | 19 | | 42 | 19 |
| Chiller | 25 | | | | | 25 |
| Meter | 21 | | 13 | 41 | 84 | 25 |
| Dehydrator | 26 | | 31 | 25 | 46 | 27 |
| Fractionation | | | | 23 | | 23 |
| Sulphur | 34 | | | 42 | | 38 |
| Compressor | 34 | | 31 | 26 | 88 | 30 |
| Vapour Recovery | | | 10 | | 41 | 10 |
| Scrubber | 22 | | 24 | 23 | 39 | 23 |
| Flare | 35 | | | 71 | 74 | 53 |

Table B.4: Generic or Average Open-ended Line Counts by Equipment/Process Type

| Equipment/Process | Light Oil Facilities | Heavy Oil Facilities | Gas Production | Gas Plants | Offshore Platforms | Overall Onshore Average |
|---|---|---|---|---|---|---|
| Well | 2 | 3 | 3 | | 20 | 3 |
| Header | 4 | 4 | 4 | 4 | 14 | 4 |
| Heater | 3 | | 4 | | 4 | 4 |
| Separator | 3 | 2 | 5 | 3 | 11 | 3 |
| Filter | | | 3 | | 8 | 3 |
| Chiller | 1 | | | | | 1 |
| Meter | 4 | | 2 | 13 | 10 | 6 |
| Dehydrator | | | 5 | 3 | 5 | 4 |
| Fractionation | | | | 2 | | 2 |
| Sulphur | 7 | | | 3 | | 5 |
| Compressor | 2 | | 5 | 2 | 12 | 3 |
| Vapour Recovery | | | 3 | | 8 | 3 |
| Scrubber | 3 | | 2 | 2 | 5 | 2 |
| Flare | 5 | | | 1 | 11 | 3 |

Table B.5: Generic or Average Compressor Seal Counts by Equipment / Process Type

| Equipment/Process | Light Oil Facilities | Heavy Oil Facilities | Gas Production | Gas Plants | Offshore Platforms | Overall Onshore Average |
|---|---|---|---|---|---|---|
| Compressor | 1 | | 2 | 3 | 2 | 2 |
| Vapour Recovery | | | | | 2 | |

Table B.6: Generic or Average PRV Counts by Equipment/Process Type

| Equipment/Process | Light Oil Facilities | Heavy Oil Facilities | Gas Production | Gas Plants | Offshore Platforms | Overall Onshore Average |
|---|---|---|---|---|---|---|
| Well | 1 | | | | | 1 |
| Header | | 3 | | | 2 | 3 |
| Heater | | | 2 | | 2 | 2 |
| Separator | 1 | | 3 | | 1 | 2 |
| Filter | | | | | 2 | 0 |
| Chiller | | | | | | 0 |
| Meter | | | 2 | 2 | 4 | 2 |
| Dehydrator | | | | 2 | 1 | 2 |
| Fractionation | | | | 1 | | 1 |
| Sulphur | | | | | | 0 |
| Compressor | | | 3 | 4 | 3 | 4 |
| Vapour Recovery | | | | | 1 | 0 |
| Scrubber | | | 2 | | 1 | 2 |
| Flare | | | | | 1 | 0 |

## Gas Transmission Facility Emission Factors for Calculation of Baseline Emissions following the Average Emission Factors Method

All values for gas transmission, storage and distribution facilities interpreted from the the Canadian Energy Parternership for Environmental Innovation (CEPEI) *Methodology Manual for the Estimation of Air Emission from the Canadian Natural Gas Transmission, Storage and Distribution System* (September, 2007).

As outlined in this guide, to apply this method, an inventory of equipment components must first be developed using the default equipment schedules in **TABLES B.7** and **B.8**. The total fugitive emissions are then calculated as outlined in **TABLE 2.5** of the protocol, using the emission factors listed in **TABLE B.9**.

## Table B.7 Default Equipment Schedules for Canadian Gas Distribution Facilities

| Type of Component | Border Meter Station[2] | District Regulator Station[1] | Gate Station[1] | Industrial Meter Set[1] | Mainline Block Valve | Reciprocating Compressor[3] | Electric Drive Reciprocating Compressor[3] | Centrifugal Compressor[3] | Compressor Station Yard Piping[4] | Compressor Discharge Coolers[5] | Residential Meter Set[1] | Commercial Meter Set[1] | Farm Tap[1] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Connectors** | 381 | 181 | 353 | 111 | 142 | 163 | 89 | 430 | 1172 | 527 | 19 | 90 | 48 |
| **Control Valves** | 1 | 1 | 2 | 0 | 1 | 1 | 1 | 5 | 19 | 0 | --- | 0 | 0 |
| **Open-Ended Lines** | 4 | 0 | 0 | --- | 1 | 4 | 4 | 5 | 22 | --- | --- | --- | --- |
| **Centrifugal Compressor Seal** | --- | --- | --- | --- | --- | --- | --- | 2 | --- | --- | --- | --- | --- |
| **Reciprocating Compressor Seal** | --- | --- | --- | --- | --- | 5 | 5 | --- | --- | --- | --- | --- | --- |
| **Pressure Relief Devices** | 3 | 2 | 3 | 1 | 1 | 2 | 1 | 2 | 18 | 1 | --- | 1 | 2 |
| **Pressure Regulators** | 8 | 8 | 12 | 4 | 2 | 1 | 0 | 3 | 18 | --- | 1 | 3 | 2 |
| **Block Valves** | 62 | 40 | 64 | 26 | 33 | 20 | 11 | 83 | 222 | 14 | 1 | 17 | 13 |
| **Blowdown Lines** | 0 | ---- | ---- | ---- | ---- | 1 | 1 | 1 | 3 | ---- | --- | --- | --- |
| **Orifice Meters** | ---- | 0 | 1 | 0 | 0 | 1 | 1 | 0 | 1 | ---- | ---- | 0 | ---- |
| **Other Flow Meters** | 1 | 0 | 1 | 1 | 0 | --- | --- | 1 | 1 | ---- | 1 | 2 | 0 |
| **Pump Seals** | --- | --- | --- | --- | --- | --- | --- | --- | 0 | ---- | ---- | ---- | ---- |
| **Instrument Controllers** | ---- | ---- | 0 | ---- | 0 | --- | --- | --- | ---- | ---- | --- | --- | --- |

[1] Number of components per meter set (for residential, commercial and industrial meter sets) or site (for district and gate stations).
[2] Number of components per meter run.
[3] Number of components per compressor unit.
[4] Number of components per compressor station. For a station with 2 reciprocating units the total number of connectors would be 2*163 + 1172 = 1498.
[5] Number of components associated with discharge coolers at compressor stations. If the station has discharge coolers, add these additional components.

Table B.8 Default Equipment Schedules for Canadian Gas Transmission Facilities

| Component | Mainline Block Valve | Receipt/ Sales Meter Station[2] | Reciprocating Compressor[3] | Electric-Drive Reciprocating Compressor[3] | Centrifugal Compressor[3] | Compressor Station Yard Piping[4] | Compressor Discharge Cooler[5] |
|---|---|---|---|---|---|---|---|
| **Connectors** | 200 | 33 | 256 | 182 | 502 | 950 | 3 527 |
| **Control Valves** | 0 | 0 | 1 | 1 | 5 | 13 | 0 |
| **Open-Ended Lines** | 1 | 0 | 0 | 0 | 4 | 6 | 2 |
| **Centrifugal Compressor Seal** | --- | --- | --- | --- | 2 | --- | --- |
| **Reciprocating Compressor Seal** | --- | --- | 4 | 4 | --- | --- | --- |
| **Pressure Relief Devices** | 0 | 0 | 2 | 1 | 3 | 8 | 0 |
| **Pressure Regulators** | 2 | 1 | 2 | 0 | 5 | 15 | 0 |
| **Block Valves** | 36 | 7 | 22 | 13 | 120 | 217 | 33 |
| **Blowdown Lines** | 0 | 0 | 1 | 1 | 1 | 4 | ---- |
| **Orifice Meters** | --- | 0 | 1 | 1 | 0 | 2 | ---- |
| **Other Flow Meters** | 0 | 1 | ---- | ---- | 0 | 1 | ---- |
| **Instrument Controllers** | 0 | 0 | 0 | 0 | 0 | 1 | ---- |

2 Number of components per meter run.
3 Number of components per compressor unit.
4 Number of components per compressor station. For a station with 2 reciprocating units the total number of connectors would be 2*256 + 950 = 1462.
5 Number of components associated with discharge coolers at compressor stations. If the station has discharge coolers, add these additional components.

Table B.9 Average Emission Factors for Estimating Fugitive Equipment Leaks at Gas Transmission and Distribution Facilities

| Source | Number of Sources | Average Emissions (kg TOC/h/source) | 95% Confidence Limits | |
|---|---|---|---|---|
| | | | Lower | Upper |
| **Gas Transmission Facilities** | | | | |
| Connector[1] | 145 829 | 4.471e-04 | 1.957e-04 | 6.985e-04 |
| Block Valve[2] | 17 029 | 4.131e-03 | 2.748e-03 | 5.514e-03 |
| Control Valve[3] | 782 | 1.650e-02 | 1.082e-02 | 2.219e-02 |
| PRV | 612 | 1.620e-01 | 2.906e-01 | 2.950e-01 |
| Regulator | 816 | 7.945e-03 | 0.000e+00 | 1.882e-02 |
| Orifice Meter[4] | 185 | 4.863e-02 | 0.000e+00 | 1.066e-01 |
| Other Flow Meter[5] | 443 | 9.942e-06 | 2.223e-07 | 1.966e-05 |

| | | | | |
|---|---|---|---|---|
| Station or Pressurized Comp. Blowdown System[6] | 219 | 3.405e+00 | 0.000e+00 | 7.885e+00 |
| Open-Ended Line | 928 | 9.183e-02 | 5.395e-02 | 1.297e-01 |
| Instrument Controller[7] | 50 | 2.371e-01 | 9.941e-02 | 3.747e-01 |
| Compressor Seal - Centrifugal[8] | 103 | 1.269e+00 | 8.197e-01 | 1.718e+00 |
| Compressor Seal - Reciprocating[8] | 167 | 1.073e+00 | 6.130e-01 | 1.533e+00 |
| **Gas Distribution Facilities and Meter/Regulator Stations** | | | | |
| **Source** | **Number of Sources** | **Average Emissions (kg TOC/h/source)** | **95% Confidence Limits** | |
| | | | **Lower** | **Upper** |
| Connector[1] | 52 051 | 8.227e-05 | 3.792e-05 | 1.266e-04 |
| Block Valve[2] | 9 817 | 5.607e-04 | 1.892e-04 | 9.322e-04 |
| Control Valve[3] | 605 | 1.949e-02 | 1.127e-02 | 2.771e-02 |
| PRV | 472 | 3.944e-03 | 0.000e+00 | 8.865e-03 |
| Regulator | 1 323 | 6.549e-04 | 0.000e+00 | 1.375e-03 |
| Orifice Meter[4] | 142 | 3.011e-03 | 1.890e-03 | 4.131e-03 |
| Other Flow Meter[5] | 348 | 7.777e-06 | 0.000e+00 | 1.752e-05 |
| Station or Pressurized Comp. Blowdown System[6] | 42 | 5.878e-03 | 0.000e+00 | 1.591e-02 |
| Open-Ended Line | 969 | 6.077e-02 | 3.086e-02 | 9.068e-02 |
| Instrument Controller[7] | 25 | 3.997e-01 | 1.158e-01 | 6.836e-01 |
| Compressor Seal - Centrifugal[8] | Use Transmission Factor | | | |
| Compressor Seal - Reciprocating[8] | Use Transmission Factor | | | |

1 Includes flanges, threaded connections and mechanical couplings.

2 Accounts for emissions from the stem packing and the valve body, and it applies to all types of block valves (e.g., butterfly, ball, globe, gate, needle, orbit and plug valves). Leakage past the valve seat is accounted for by the Open-Ended Line emission category. Leakage from the end connections is accounted for by the connector category (i.e., one connector for each end).

3 Accounts for leakage from the stem packing and the valve body. Emissions from the controller and actuator are accounted for by the Instrument Controller and Open-Ended Line categories respectively. This factor applies to all valves with automatic actuators (including fuel gas injection valves on the drivers of reciprocating compressors).

4 Accounts for emissions from the orifice changer. Emissions from sources on pressure tap lines etc. are not included in the factor (i.e., these emissions must be calculated separately).

5 Accounts for emissions from other types of gas flow meters (e.g., diaphragm, ultrasonic, roots, turbine and vortex meters).

6 Accounts for leakage past a valve seat through an open vent line to the atmosphere. These vents are typically six inches or greater in diameter and are used to blowdown major process units or sections of pipeline. Small diameter open-ended lines such as those used to blowdown chart recorders, meter runs etc. are accounted for by the Open-Ended Line category.

7 The Instrument Controller category accounts for emissions from pneumatic control devices that use natural gas as the supply medium.

8 The Compressor Seal categories account for emissions from individual compressor seals (i.e., for a four cylinder reciprocating compressor unit there are four seals so the compressor seal emissions for the unit would be four times the factor in the table).

9 Accounts for leakage past the seats on the compressor unit suction and discharge valves when the compressor is depressurized (i.e., the blowdown valve is open to the atmosphere) and there is pressure on the pipeline side of these two isolation valves.

## Emission Factors for Fossil Fuel Combustion

All values interpreted from Volume 1 of the technical report: A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide ($H_2S$) Emissions by the Upstream Oil and Gas Industry dated September 2004 completed by Clearstone Engineering Ltd. on behalf of the Canadian Association of Petroleum Producers (CAPP).

Table B.10: Emission Intensity of Combustion

| **Natural Gas** | | |
|---|---|---|
| **Industrial** | | |
| Emissions Factor ($CO_2$) | 1.891 | kg $CO_2$ per $m^3$ |
| Emissions Factor ($CH_4$) | 0.00049 | kg $CH_4$ per $m^3$ |
| Emissions Factor ($N_2O$) | 0.000049 | kg $N_2O$ per $m^3$ |
| **Producer Consumption** | | |
| Emissions Factor ($CO_2$) | 2.389 | kg $CO_2$ per $m^3$ |
| Emissions Factor ($CH_4$) | 0.0065 | kg $CH_4$ per $m^3$ |
| Emissions Factor ($N_2O$) | 0.00006 | kg $N_2O$ per $m^3$ |

# Appendix C

# Alternate Quantification Approach

The approach outlined in **TABLE C.1** below, may be used to quantify baseline methane emissions for large unplanned emission sources that are detected using one of the technologies described in Appendix A. This approach is included at the request of AENV, to allow for a comparison of the emission reductions calculated for a given facility, using the approach outlined in the protocol, with the emission reductions calculated based on an instantaneous measurement of methane emissions before and after repair (i.e. in both the project and baseline conditions).

It is generally the case that a relatively small number of fugitive sources account for the vast majority of the overall fugitive emissions at natural gas facilities. In work done by CETAC-west it was found that, on average, just 10 emission sources out of thousands of potential sources accounted for 80 to 90% of the overall fugitive gas emissions at large gas plants (CETAC-west, 2005).

As such, given that the majority of fugitive methane emissions are attributable to 10% to 20% of the emission sources at a given facility, measuring the large unplanned sources of emissions should provide a reasonable mechanism for comparison of the two approaches discussed above. Note however that the method outlined in the protocol is based on continuous monitoring of the overall methane emissions at the facility level, while the approach included in this appendix provides a snapshot of emissions at a given point in time. As such, they may not be directly comparable. Further, as discussed in the Technical Seed Document related to this protocol, the emissions measured using virtually continuous monitoring should increase the accuracy of the emission reduction claim.

The approach outlined in **TABLE C.1** may also be applicable for projects where the size / complexity of the facility warrants the use of a simpler and less costly approach. In this case, fugitive methane emissions may be quantified by measuring the flow rate using a direct measurement technique (i.e. in-line flow meter, bagging, hi-flow sampler, isolation flux chamber, etc.). Justification that the approach is appropriate and that emission reductions would not have been detected in the absence of the project, must be provided by the project proponent.

Table C.1: Quantification of Emissions from Large Unplanned Fugitive Emission Sources

| 1.0 Project/ Baseline SS | 2. Parameter / Variable | 3. Unit | 4. Measured / Estimated | 5. Method | 6. Frequency | 7. Justify measurement or estimation and frequency |
|---|---|---|---|---|---|---|
| **Project SSs** | | | | | | |
| P4 Venting<br>P5 Fugitive Losses | $\text{Emissions}_{\text{Methane (Project)}} = \sum (Q_{\text{Leak } i} * \% \text{ Vol. } CH_4 * \text{Project Hrs}_i * \rho_{CH4} * GWP_{CH4})$ | | | | | |
| | Emissions $_{\text{Methane (Project)}}$ | kg of $CO_{2E}$ | N/A | N/A | N/A | Quantity being calculated. Project emissions will be measured and monitored virtually continuously using direct measurement and complete site coverage. |
| | Flow Rate of Each Equipment Leak / $Q_{\text{Leak } i}$ | $m^3$ / hr | Measured | Direct measurement of flow rate of gas of leaking component using a bag and stopwatch, rotameter, hi-volume, hi-flow sampler or other appropriate measurement technique. | Following detection using one of the methodologies listed in Appendix A or other similar technology. Flow rate will be assessed on a per emission source / leak basis. | Direct measurement represents industry best practice. The flow rate of the leaking component will be measured prior to fixing the leak.<br>Note that similar equipment / processes may be aggregated. The project proponent should be prepared to provide justification to demonstrate that this is appropriate. |
| | $CH_4$ Composition in Gas Stream (Volumetric Basis) / % Vol. $CH_4$ | % | Measured | Direct measurement of the percent methane composition by volume of the gas stream. | Quarterly | Direct measurement represents industry best practice. Composition may vary throughout the project. Quarterly gas composition measurement is reasonable for operation of an oil and gas facility |
| | Hours Operational during Project Monitoring Period / Project Hrs $_i$ | Hrs | Measured | Measurement of the duration of time the unit or process has been operating. | Monthly | The number of hours the unit or process has been operational will be used to assess the project emissions from the process or component. |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Density of $CH_4$ / $\rho_{CH4}$ | kg / $m^3$ | Constant | 717 kg/$m^3$ at standard temperature and pressure (STP). | Reference Value | N/A |
| **Baseline SSs** | | | | | | |
| B4 Venting<br>B5 Fugitive Losses | $\text{Emissions}_{\text{Methane (Baseline)}} = \sum (Q_{\text{Leak } i} * \% \text{ Vol. } CH_4 * \text{Project Hrs}_i * \rho_{CH4}) * GWP_{CH4}$ | | | | | |
| | $\text{Emissions}_{\text{Methane (Baseline)}}$ | kg of $CO_{2E}$ | N/A | N/A | N/A | Quantity being calculated.<br>Note that this quantity must be determined for large unplanned emission sources, prior to repair. This information is required by AENV for comparison with the emission reductions quantified using the industry standard baseline approach used in this protocol. |
| | Flow Rate of Each Type of Equipment Leak / $Q_{\text{Leak } i}$ | $m^3$ / hr | Measured | Direct measurement of flow rate of gas of leaking component using a bag and stopwatch, rotameter, hi-volume, hi-flow sampler or other appropriate measurement technique. | Following detection using one of the methodologies listed in Appendix A or other similar technology. Flow rate will be assessed on a per emission source / leak basis. | Direct measurement represents industry best practice. The flow rate of the leaking component will be measured prior to fixing the leak.<br>Note that equipment / processes may be aggregated if applicable. The project proponent should be prepared to provide justification to demonstrate that this approach is appropriate. |
| | $CH_4$ Composition in Gas Stream (Volumetric Basis) / % Vol. $CH_4$ | % | Measured | Direct measurement of the percent methane composition by volume of the gas stream. | Quarterly | Direct measurement represents industry best practice. Composition may vary throughout the project. Quarterly gas composition measurement is reasonable for operation of an oil and gas facility |
| | Hours Operational during Project Monitoring Period / | Hrs | Measured | Measurement or reasonable approximation of the hours the unit or process has been operational in the project condition. | Monthly | The number of hours the unit or process has been operational will be used to assess the monthly methane emissions from the leaking component. |

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|---|---|---|---|---|---|---|
|  | Project Hrs $_i$ |  |  |  |  |  |
|  | Density of $CH_4$ / $\rho_{CH4}$ | kg / $m^3$ | Constant | 717 kg/$m^3$ at standard temperature and pressure (STP). | Reference Value | N/A |
| Multiple Project and Baseline SSs | Global Warming Potential of Methane / $GWP_{CH4}$ | kg $CO_{2E}$ / kg $CH_4$ | Estimated | From Environment Canada; IPCC. | Annual | The applicable global warming potential of $CH_4$ is 21, as per the Intergovernmental Panel on Climate Change. *Climate Change 1995: The Science of Climate Change* (Cambridge, UK: Cambridge University Press, 1996). This value should be used for all calculations, to maintain consistency with internationally accepted best practice guidance. |