

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

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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, etc¹. 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 CO₂ and N₂O emissions are negligible². Given that that project activity serves to reduce fugitive emissions, it is also conservative to exclude consideration of vented CO₂. In addition, it is conservative not to include either CO₂ or N₂O in the project scenario, as any reduction in fugitive methane emissions may also result in a decrease in CO₂ and / or N₂O emissions. For example, reduced venting at sour gas facilities may result in lower CO₂ 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. 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

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*.

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 frequency³.

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 emissions⁴. 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

³ 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*.

⁴ *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 sources⁵:

- 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.

⁵ 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) 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 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.

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FIGURE 1.1: Process Flow Diagram for Project Condition

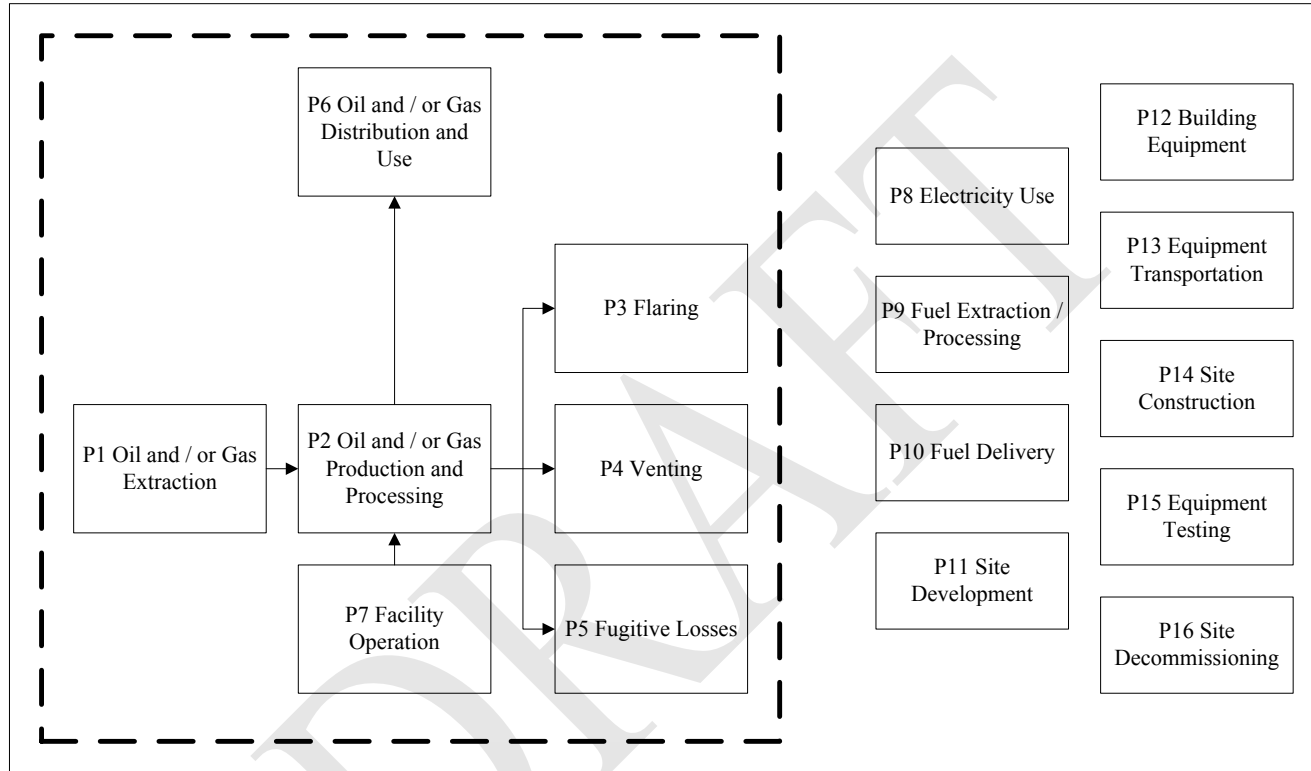
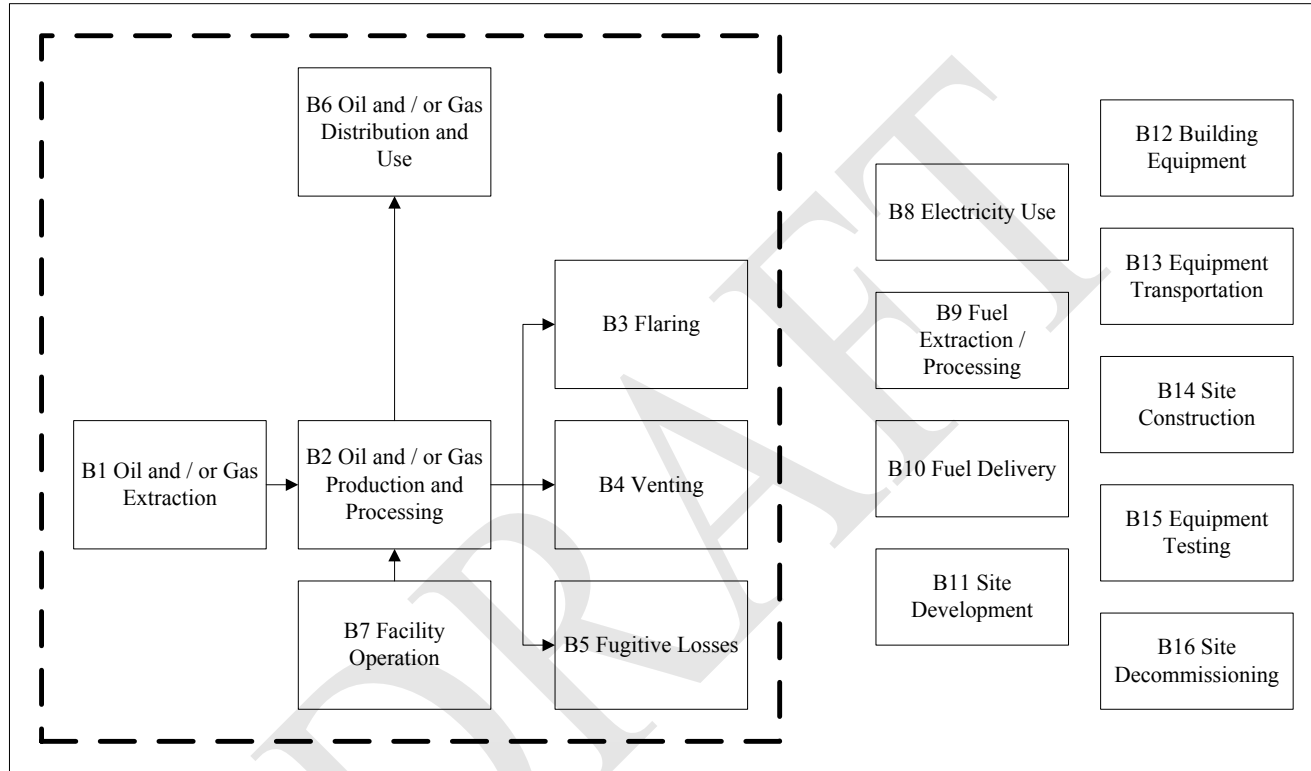


FIGURE 1.2: Process Flow Diagram for Baseline Condition



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 C⁶. 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 CO₂ 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 propose the use of a measurement and monitoring program that does not provide complete site coverage, provided that the approach allows for a level of accuracy consistent with the protocol requirements. Justification should be provided to explain how the chosen methodology and/or equipment provides equivalent and / or more conservative data than would have been achieved with complete site coverage;
 - a. This approach may be applicable to projects developed at for projects that involve a limited number of processes / equipment (i.e. replacing wet seals with dry seals on turbine compressors, modification of procedures in order to reduce natural gas venting during planned maintenance events, etc); and
3. Project proponents may propose a measurement and monitoring frequency other than what is outlined in this protocol (i.e. virtually continuous monitoring), provided that the monitoring frequency allows for a level of accuracy consistent with the protocol requirements. Justification should be provided to explain how methane emissions are forecast for the months that are not measured and to demonstrate that the approach is conservative;

⁶ 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 (i.e. single well batteries, satellite batteries, and field facilities);
- b. This approach may also be applicable at facilities where methane emissions are not found to vary materially from month to month. In this case, measurements would be used by the project proponent to create an annual methane emission profile for the facility.

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).

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, etc⁷.

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 (m³) of methane emitted. This common metric allows for analysis and comparison of total facility methane emissions.

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 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

⁷ Canadian Association of Petroleum Producers (CAPP). (2003). CH4 and VOC Emissions: Volume 4.

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”⁸.
- 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 flows⁹.

⁸ 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.*

⁹ *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

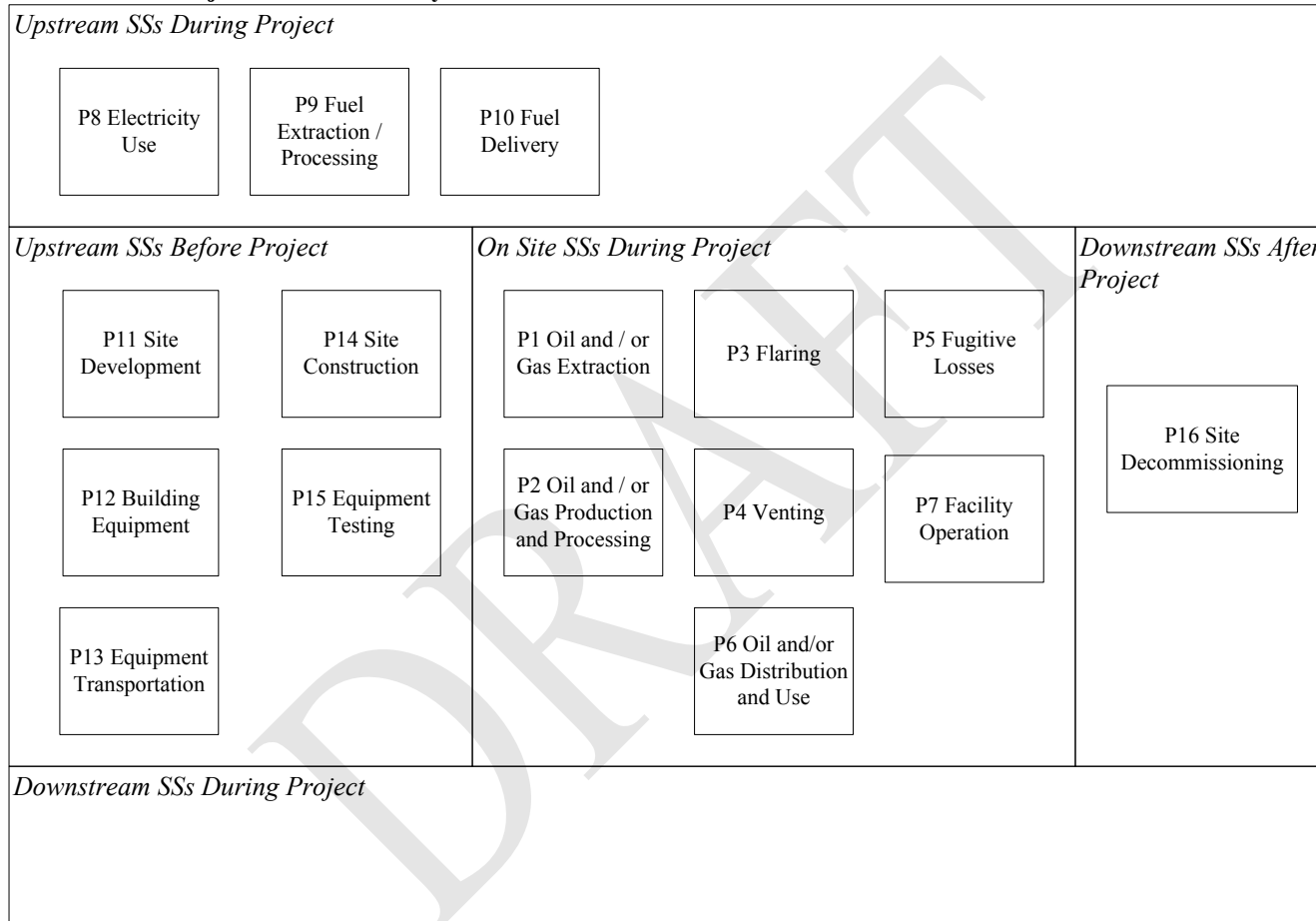


TABLE 2.1: Project SSs

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 be 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 ¹⁰	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 ¹¹	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

¹⁰ 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.*

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.*

1. SS	2. Description	3. Controlled, Related or Affected
	<p>devices. Venting may occur either continuously or intermittently. The quantity of gas vented would need to be tracked.</p> <p>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.</p> <p>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.</p>	
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
P6 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 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		
None.		
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 used to power equipment for the extraction of the raw materials, processing, fabricating and	Related

1. SS	2. Description	3. Controlled, Related or Affected
	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	<p>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.</p> <p>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.</p>
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	<p>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.</p> <p>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.</p> <p>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.</p>
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	<p>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.</p>

Baseline Options	Description	Static/ Dynamic	Accept or Reject and Justify
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 Partnership 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.

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

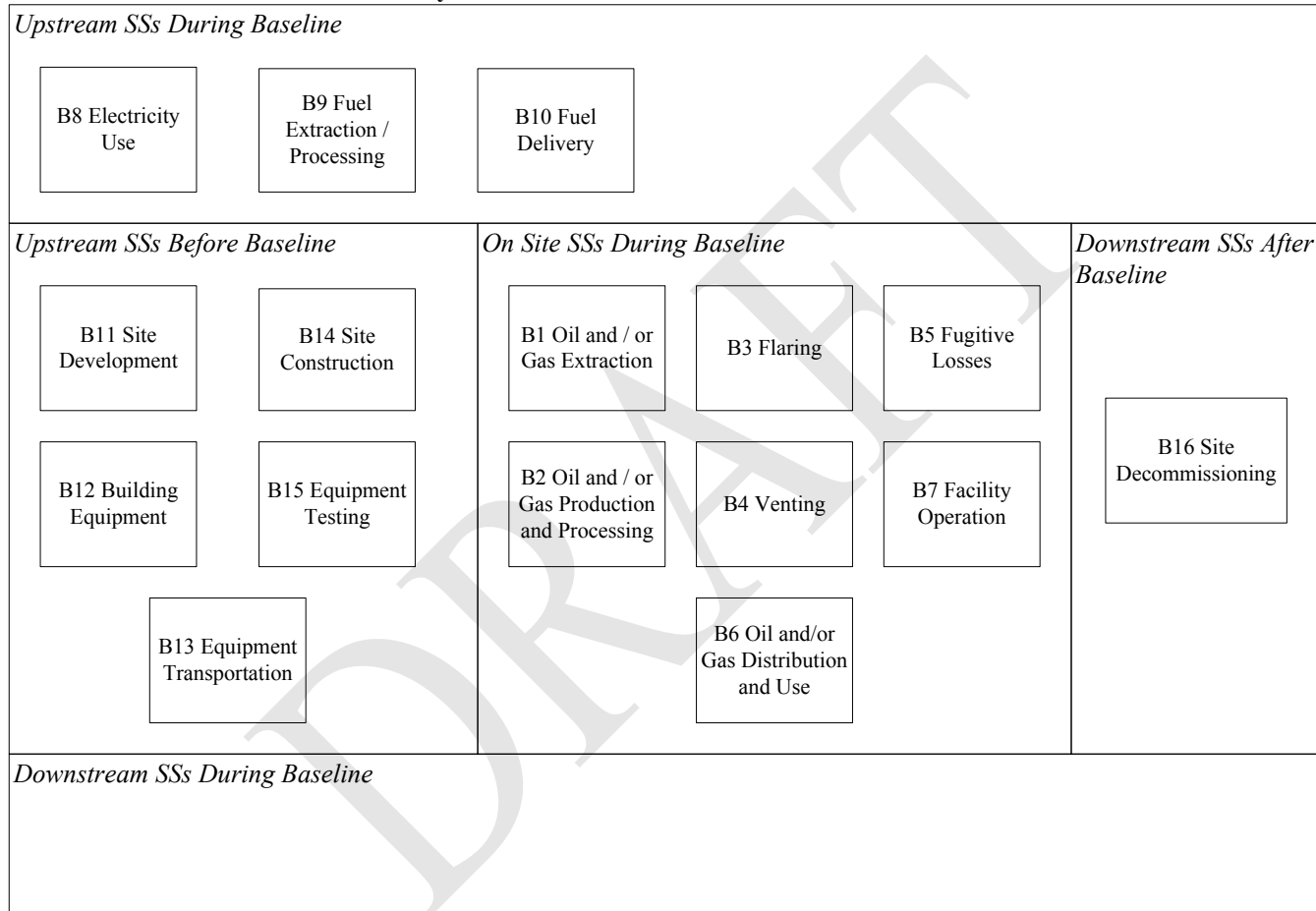


TABLE 2.3: Baseline SSs

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 be 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 ¹²	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 ¹³	Venting is a common means of disposing of waste gas at oil and gas facilities and is defined as	Controlled

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.*

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.*

1. SS	2. Description	3. Controlled, Related or Affected
	<p>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.</p> <p>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.</p> <p>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.</p> <p>Note that emissions of vent gases will be accounted for under the SS B5 Fugitive Losses.</p>	
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
B6 Oil and / or Gas Distribution and Usage	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		
None.		
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
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.	Related

1. SS	2. Description	3. Controlled, Related or Affected
	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.	
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.

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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
P6 Oil and / or Gas Distribution and Use	N/A	Related	Exclude	Excluded as these SSs are likely equivalent under the project and baseline conditions.
B6 Oil and / or Gas Distribution and Use	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				
None.				
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 required.
B16 Site Decommissioning	Related	N/A	Exclude	

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.

Comment [KB1]: Note that 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	$\text{Emissions}_{\text{Flaring}} = (\text{Emissions}_{\text{Methane (Baseline)}} - \text{Emissions}_{\text{Methane (Project)}}) * (1 - \text{Eff}) * \text{GWP}_{\text{CH}_4};$ $(((\text{Emissions}_{\text{Methane (Baseline)}} - \text{Emissions}_{\text{Methane (Project)}}) * \text{Eff} * \text{EF}_{\text{CO}_2}) / \rho_{\text{CH}_4});$ $(((\text{Emissions}_{\text{Methane (Baseline)}} - \text{Emissions}_{\text{Methane (Project)}}) * \text{Eff} * \text{EF}_{\text{N}_2\text{O}}) / \rho_{\text{CH}_4});$					
	Emissions Flaring	kg of CO _{2E}	N/A	N/A	N/A	<p>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 CO₂. The project proponent also has the option of demonstrating that methane is not flared.</p> <p>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.</p> <p>N₂O 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.</p>
	Total Baseline Methane Emissions / Emissions <small>Methane (Baseline)</small>	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 / Emissions <small>Methane (Baseline)</small>	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_{CH_4}	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. Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	EF _{N2O}	kg N ₂ O / 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 ₂ O emissions from combusting the methane gas stream. This approach is consistent with the Alberta Quantification Protocol for Landfill Gas Capture and Combustion. Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	$Emissions_{Methane (Project)} = \sum (Measured Leak Vol._{Methane} * \rho_{CH_4} * GWP_{CH_4})$					
P4 Venting P5 Fugitive Losses	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. 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. 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 / ρ _{CH4}	kg / m ³	Constant	717 kg/m ³ at standard temperature and pressure (STP).	Reference Value	N/A
Baseline SSts						
	$Emissions_{Methane (Baseline)} = \sum (N_i * F_i * \% \text{ Mass } CH_4 * Project \text{ Hrs} * GWP_{CH_4})$					
B4 Venting	Emissions Methane (Baseline)	kg of CO _{2E}	N/A	N/A	N/A	Quantity being calculated. 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.
B5 Fugitive Losses	Number of Fittings of Type i / N _i	-	Estimated	From the Canadian Association of Petroleum Producers (CAPP) and the Canadian Energy Partnership 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. 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 Partnership 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.
$\% \text{ Mass CH}_4 = (\% \text{ Vol. CH}_4 * \text{MW}_{\text{CH}_4}) / \text{MW}_{\text{Gas}}$						
	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_{CH_4}	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_{CH_4}	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. <i>Climate Change 1995: The Science of Climate Change</i> (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 to¹⁴:

- 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.

¹⁴ CAPP. (1999). CH₄ 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 <small>Methane (Baseline)</small>				None	
	Total Project Methane Emissions / Emissions <small>Methane (Baseline)</small>				None	
P4 Venting P5 Fugitive Losses	Measured Volume of Methane Emissions / Measured Leak Vol. <small>Methane</small>				None	
Baseline SSs						
B4 Venting 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

DRAFT

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 sampling¹⁵. 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	Virtually	Complete
	Quantification	Continuous	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

¹⁵ CAPP. (1999). CH₄ 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 rate¹⁶. The project proponent should refer to CAPP's (1999) publication entitled: *CH₄ 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 leaks¹⁷. 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 proprietary 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)¹⁸

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, CH₄, H₂S 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

¹⁶ CAPP. (1999). CH₄ and VOC Emissions from the Canadian Upstream Oil and Gas Industry – Volume 4

¹⁷ 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*.

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*.

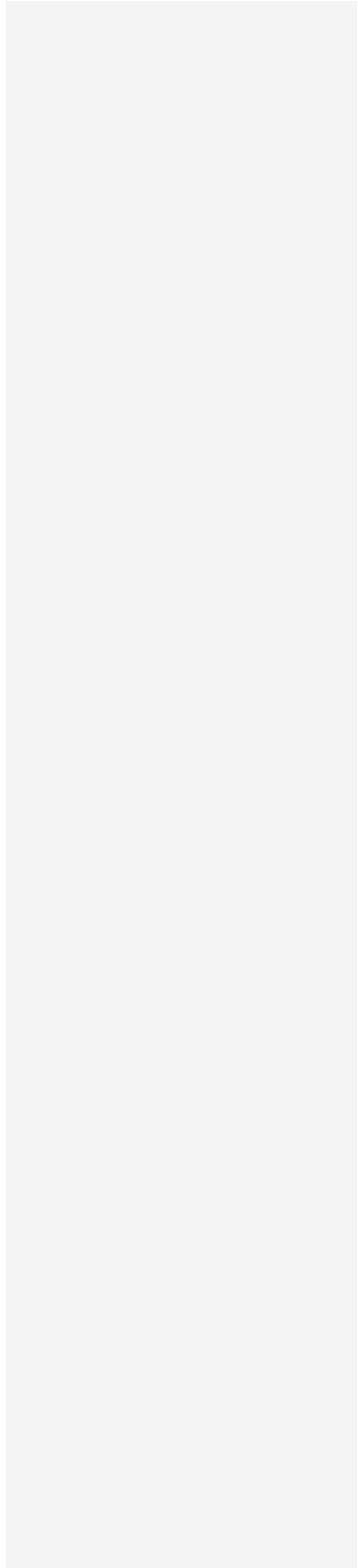
fraction of light absorption caused by the target gas molecules between the detector and a target or passive reflector, which is then used to calculate the gas's concentration.

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 CO₂. 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.

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Appendix B
Relevant Emission Factors

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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 Association 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 CH₄ 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 CH₄ 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"¹⁹.

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

¹⁹ 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 Partnership 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**.

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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	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 $2 \times 163 + 1172 = 1498$.

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 $2 \times 256 + 950 = 1462$.

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 (H₂S) 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 ₂ O)	0.000049	kg N ₂ O 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 ₂ O)	0.00006	kg N ₂ O per m ³

Appendix C
Alternate Quantification Approach

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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						
$\text{Emissions}_{\text{Methane (Project)}} = \sum (Q_{\text{Leak } i} * \% \text{ Vol. CH}_4 * \text{Project Hrs } i * \rho_{\text{CH}_4} * \text{GWP}_{\text{CH}_4})$						
P4 Venting P5 Fugitive Losses	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 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. 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 / ρ _{CH4}	kg / m ³	Constant	717 kg/m ³ at standard temperature and pressure (STP).	Reference Value	N/A
Baseline SSs						
Emissions _{Methane (Baseline)} = ∑ (Q _{Leak i} * % Vol. CH ₄ * Project Hrs _i * ρ _{CH4}) * GWP _{CH4}						
B4 Venting B5 Fugitive Losses	Emissions Methane (Baseline)	kg of CO _{2E}	N/A	N/A	N/A	Quantity being calculated. 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 _{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. 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.

	Project Hrs _i					
	Density of CH ₄ / ρ _{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. <i>Climate Change 1995: The Science of Climate Change</i> (Cambridge, UK: Cambridge University Press, 1996). This value should be used for all calculations, to maintain consistency with internationally accepted best practice guidance.