Quantification protocol for vent gas reduction

Technology Innovation and
Emissions Reduction (TIER) Regulation
Version 1.0

Quantification Protocol for Vent Gas Reduction | Alberta Environment and Parks
 | November 9, 2021 | ISBN 978-1-4601-5166-2

Summary of Revisions

Version	Date	Summary of Revisions
1.0	November 2021	• Replaces the Quantification Protocol for Solution Gas Conservation; highlights of revisions compared with Solution Gas below: • The **Protocol Scope** was modified to only allow tie into existing flares, and disallow new flares. • The **Protocol Scope** was modified to reflect changes to regulatory additionality under AER's Directive 060, permitting destruction through incineration or tying in to existing flares as a project condition, clarifying the types of vent gas that are/are not eligible for offset creation and generally aligning requirements with Directive 060. • The **type of baseline** was changed to a capped dynamic baseline so that emission offsets are limited to the lower of actual metered vent gas captured or the Overall Vent Gas (OVG) Limit in Directive 060, to ensure project reductions meet the requirements of regulatory additionality. • Three **Flexibility Mechanisms** were added to account for different baseline requirements for: o sites where the Defined Vent Gas (DVG) applies o sites where the Crude Bitumen Fleet Average (CBFA) applies and o sites capturing vent gas from compressor seals. This is to ensure alignment with Directive 060 and therefore regulatory additionality. • **Offset eligible and priced emission reductions sections** were added to ensure alignment with carbon pricing. • The **Quantification Methodology** reflects a capped dynamic baseline, and align with the Alberta Greenhouse Gas Quantification Methodologies. • The **Documents and Records** requirements were updated to align with the updated scope and eligibility.

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Related Publications

- *Emissions Management and Climate Resilience Act* (the Act)
- Technology Innovation and Emissions Reduction Regulation (the Regulation)
- Standard for Greenhouse Gas Emission Offset Project Developers
- Standard for Validation, Verification and Audit
- Technical Guidance for Offset Protocol Development and Revision
- Carbon Offset Emission Factors Handbook
- Alberta Greenhouse Gas Quantification Methodologies

1 Offset Project Description

This quantification protocol establishes a methodology for quantifying GHG emission reductions from capturing small volumes of vented gas from oil and gas sites in Alberta for conservation or destruction.

Natural gas is composed mostly of methane, which is a greenhouse gas (GHG) with a global warming potential (GWP) many times that of carbon dioxide. The Alberta Energy Regulator (AER) regulates gas and methane venting at sites in the oil and gas industry via Directive 060. The current limit for venting from a site in Directive 060 is the Overall Vent Gas Limit (OVG), which is 15,000 m^3/month of vent gas, OR 9,000 kg/month of methane (CH_4) (this means that a site is in compliance with the OVG if it meets either the volume limit OR the mass limit – it does not need to meet both).

The opportunity for emission offset reduction activities applying this protocol is for projects that reduce emissions below the OVG.

Furthermore, Directive 060 sets out limits for venting at sites that produce first gas after January 1, 2022 (i.e. greenfield sites). Projects that are at sites that produce first gas after January 1, 2022 have an opportunity to generate emission offsets by applying Flexibility Mechanism 1

Directive 060 also provides an option for certain sites to subscribe to the Crude Bitumen Fleet Average (CBFA) approach. Projects that include sites subscribing to the CBFA have an opportunity to generate emission offsets by applying Flexibility Mechanism 2.

Directive 060 stipulates certain additional requirements for venting from compressor seals. There is an opportunity for emission offset projects to generate emission offsets that apply Flexibility Mechanism 3 at sites that include vent gas capture from compressor seals.

In order to use this protocol it is expected that emission offset project developers have familiarity with the requirements of Alberta's Emission Offset System, Directive 060, venting sources within the oil and gas industry, the application of vent gas capture and destruction technologies, and how to apply greenhouse gas quantification methodologies. This project activity may be aggregated per the Standard for Greenhouse Gas Emission Offset Project Developers; all subprojects must meet and follow all requirements listed for a 'project' in this protocol, unless otherwise noted.

1.1 Protocol Scope

This protocol is applicable to emission reductions by conserving or destroying vent gas at oil and gas sites regulated by Directive 060. This protocol is applicable only for emission reductions that are not subject to a carbon price by any other policy mechanism and that are not required by Directive 060.

The scope of the greenhouse gases eligible under this protocol are carbon dioxide, methane, and nitrous oxide.

The emission reductions eligible to generate emission offsets using this protocol are from either conserving or destroying vent gas. There are two separate and distinct categories of eligible emission reduction activities:

Category 1: conservation (conserving) activities including:

- Injection into a sales gas pipeline,
- Stationary fuel combustion including:
    - On-site use as fuel gas, and
    - On-site use for power generation.

Category 2: vent gas destruction (destroying) activities including:

- Incineration, and
- Tying in to an existing flare (no new flares).

Category 1 and Category 2 emission offset subprojects can be listed in the same emission offset project provided that each subproject is clearly identified as Category 1 or 2 in the accompanying Aggregated Project Planning Sheet (APPS).

The following project types are **<u>not</u>** <u>eligible</u> to generate emission offsets using this protocol:

- projects with a baseline condition of flaring (e.g. flare gas to power projects).
- projects that involve the installation of a new flare at a site that does not have a flare in the baseline/pre-project.
- projects that occur at a facility that is a large emitter or at a TIER opt-in facility. Note: Conventional oil and gas facilities that have entered TIER as part of an aggregate facility are currently eligible as long as the emission reduction is not subject to a carbon price.

- projects at a site that have a combined flared, vented and incinerated volumes (FVI) of more than 900 m^3/day and are required to conserve as defined by Directive 060.
- projects at a site that has been directed by the AER to conserve.
- projects that are at sites located in the Peace River Area as defined in Directive 084.
- projects at a site where the gas to oil ratio is >3,000 m^3/m^3.
- flaring projects at a site within 500 m of a residence.
- projects that achieve emission reductions from geological sequestration (e.g. enhanced oil recovery or injection for disposal).
- projects that achieve emission reductions from conservation or destruction of vented gas used to operate pneumatic devices, and compressor starters. Note: These projects may be eligible to use the Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices.
- projects that reduce emissions by shutting in a site.

1.2 Protocol Applicability

Emission offset project developers must demonstrate that the emission offset project meets the requirements of the Alberta Emission Offset System, relevant greenhouse gas regulations, this quantification protocol and the Carbon Offset Emission Factors Handbook. The emission offset project developer must explain and provide evidence to demonstrate that the project and all subprojects in an aggregated emission offset project meet the following requirements:

1. The emission reductions must occur at a site regulated by Directive 060.
2. The emission reductions must have an activity start date on or after January 1, 2020.
3. The site where the emission offset project (or subproject) is located must be compliant with Directive 060 in the project condition (i.e. after the emission offset project is implemented).
4. The emission reductions must occur at a site that is subject to the Overall Vent Gas (OVG) Limit in Directive 060 (unless the sites are using Flexibility Mechanism #1 or #2, which must be documented and justified).
5. The site where the emission offset project (or subproject) is located must be ‘active’ as defined by Directive 060 for the two years prior to the activity start date for the emission offset project (or subproject). The site must report production for at least 4,380 hours in each year for two years prior to the activity start date.
    - If the site is new and was developed less than two years prior to the activity start date for the emission offset project (or the subproject), the site must be ‘active’ as defined by Directive 060 in the baseline scenario for the emission offset project (or subproject) for each year before the activity start date for the emission offset project (or subproject).The site must report production for at least 4,380 hours in the 365 days prior to the activity start date for the subproject.
    - If the site where the emission offset project (or subproject) is located receives or produces first gas after either the publication of this protocol or January 1, 2022 and is subject to the Defined Vent Gas Limit (DVG) in Directive 060 it is only eligible to generate emission offsets if using and meeting all requirements under Flexibility Mechanism 1.
6. If the site where the emission offset project (or subproject) is located chooses to apply the crude bitumen fleet average (CBFA) as defined in Directive 060, it is only eligible to generate emission offsets if using and meeting all requirements under Flexibility Mechanism 2.
7. If the emission offset project (or subproject) includes the conservation or destruction of vent gas from compressor seals, it is only eligible to generate emission offsets if using and meeting all requirements under Flexibility Mechanism 3

1.3 Flexibility Mechanisms

Where an emission offset project developer uses one or more flexibility mechanisms listed below, they must provide additional justification and rationale for how the flexibility mechanism applies to their activity and how it is applied. This is in addition to meeting all other requirements of the protocol and Alberta Emission Offset System. A clear explanation of the flexibility mechanism and alignment with the protocol quantification must be demonstrated in the offset project plan and, if applicable, the offset project report.

Flexibility Mechanism 1:

Applies to a site that receives or produces first gas after January 1, 2022 and is subject to the defined vent gas limit (DVG) in Directive 060. The site may generate emission offsets using a capped dynamic baseline of 3,000 m^3/month of vent gas OR 1,800 kg/month of CH_4. The project developer must calculate monthly volume or mass calculations according to section 4.1.6. As with the OVG, this means that a site is in compliance with the OVG if it meets either the volume limit OR the mass limit – it does not need to meet both. All other protocol conditions/requirements remain unchanged.

Flexibility Mechanism 2:

Applies to a site that is opted into the Crude Bitumen Fleet Average (CBFA) in Directive 060. In order to use this flexibility mechanism, the site must be in compliance with the OVG in the baseline condition, and the fleet must be in compliance with the CBFA in the baseline condition. The site may generate emission offsets using a capped dynamic baseline of 15,000 m^3/month as long as it can be demonstrated that the fleet is in continual compliance with the CBFA during the offset crediting period. If the fleet is not in compliance with the CBFA, no sites are able to generate emission offsets for the time period that the fleet is not in compliance. All other protocol conditions/requirements remain unchanged. Note that where a site initiated a vent gas reduction project under the protocol prior to opting-in to the CBFA, this Flexibility Mechanism must be used from the date on which the site opted in to the CBFA.

Flexibility Mechanism 3:

Applies where a project involves vent gas capture from a compressor seal. The site may only generate emission offsets if the project developer can demonstrate that any included compressors met the requirements of Directive 060 in relation to compressor seal vent gas limits in the baseline condition i.e. pre-project. The project (or subproject) site must meet the requirements of the OVG, DVG, or CBFA whichever is applicable. All other protocol conditions/requirements remain unchanged.

1.4 Offset Crediting Period

Emission offset projects (and subprojects) that are in **Category 1** (conservation) are eligible for an eight year offset crediting period with the potential for extension(s). Category 1 projects may also apply to the Director for a 10-year crediting period (with no extensions, as outlined in the Standard for Greenhouse Gas Emission Offset Project Developers.

Emission offset projects (and subprojects) that are in **Category 2** (vent gas destruction) are eligible for an offset crediting period ending on or before September 30, 2025. Category 2 projects are not eligible to apply to the Director for a 10-year offset crediting period.

1.5 Glossary of Terms

Alberta Energy Regulator (AER)	The agency of the Government of Alberta that regulates the safe, responsible and efficient development of Alberta’s energy resources (oil, natural gas, oil sands, coal), pipelines and subsurface sequestration activities.
Combustion	Burning of a solid, liquid or gaseous fuel for the purpose of providing useful heat or energy. For the purpose of this Protocol, this includes a combustion device, such as an engine or boiler, but specifically excludes devices that are considered flares or incinerators (an enclosed combustor).
Conservation	The capture of vented gas for the purpose of injecting into a sales gas pipeline or providing useful heat or energy.
Crude Bitumen Fleet Average (CBFA)	As defined in Directive 060, this is the sum of the vent volumes from the crude bitumen fleet divided by the total number of facility IDs within the crude bitumen fleet.
Defined Vent Gas (DVG)	As defined in Directive 060, this is vent gas from routine venting, excluding from pneumatic devices, compressor seals, and glycol dehydrators.
Destruction	The flaring, or incineration of vented gas.
Directive	A document setting out new or amended requirements or processes to be implemented and followed by licensees, permittees, and other approval holders under the jurisdiction of the AER.

Directive 007	*Volumetric and Infrastructure Requirements (February 2016).* This directive sets out the AER's requirements for reporting volumetric data and well status changes using the Canada's Petroleum Information Network (Petrinex), and it prescribes the manner in which data is submitted.
Directive 017	*Measurement Requirements for Oil and Gas Operations (March 2016).* This directive clarifies, consolidates and updates the AER requirements for measurement points used for accounting and reporting purposes, as well as those measurement points required for upstream petroleum facilities and some downstream pipeline operations under existing regulations. The directive does not include instructions on how the volumes are reported to the AER (see *Directive 007*).
Directive 060	*Upstream Petroleum Industry Flaring, Incinerating, and Venting (January 2020).* This directive sets out requirements for flaring, incinerating, and venting in Alberta at all upstream petroleum industry wells and facilities. These requirements also apply to pipeline installations that convey gas (e.g., compressor stations, line heaters) licensed by the AER in accordance with the Pipeline Act. With the exception of oil sands mining schemes and operations, *Directive 060* applies to all schemes and operations approved under section 10 of the Oil Sands Conservation Act.
Directive 084	*Requirements for Hydrocarbon Emission Controls and Gas Conservation in the Peace River Area (September 2018).* This directive sets out requirements for addressing odours and emissions generated by heavy oil and bitumen operations in the Peace River area of Alberta.
Flare Gas	As defined by Directive 060, this is gas that is combusted in a flare or incinerator at upstream oil and gas operations.
Flaring	Flaring is the controlled burning of a gas or liquid stream produced at a facility, used for routine or emergency disposal of a hazardous waste stream, where the main purpose is not energy production. For the purpose of this Protocol, this includes flare pits, ground flares, flare stacks and enclosed flares but does not include enclosed combustors or incinerators.
GHG Sink	Process that removes a greenhouse gas from the atmosphere. [Source: ISO 14064-2:2019]
GHG Source	Process that releases a greenhouse gas into the atmosphere [Source: ISO 14064-2:2019]
Incineration	Incineration is the controlled mixing and burning of waste gas or liquid streams, air and fuel in an enclosed chamber, used for routine disposal of a hazardous waste stream, where the main purpose is not energy production. For the purpose of this Protocol, this includes incinerators and enclosed combustors only.
Pneumatic Devices	Gas-driven pneumatic instruments, including pneumatic instruments (e.g. controllers, switches, transducers and positioners) and pneumatic pumps, as defined by Directive 060.

Overall Vent Gas (OVG)	As defined in Directive 060, this is all routine and non-routine vent gas.
Site	As defined in Directive 060, a site is a single-surface lease (pads counted as one lease) where gas is flared or vented. For the purposes of applying this protocol the site is the project boundary (or the subproject boundary in the case of an aggregated project).
Vent Gas	As defined in Directive 060, this is uncombusted gas that is released to the atmosphere at upstream oil and gas operations. Vent gas does not include fugitive emissions.

2 Baseline Condition

The baseline condition for the emission reduction activity is venting of gas to the atmosphere.

The quantification of the baseline for this protocol is site specific and projection-based. This means that the gas captured during the project must be measured and is projected to the baseline to quantify what would have been vented in the absence of the project. The total quantity of gas captured must be measured after the point of capture, and upstream of any mingling or point of use.

To ensure emission reductions that are beyond regulatory requirements, the baseline is limited to a maximum “cap” that is the OVG limit in Directive 060, minus any venting reported at the project site during the project condition (as this also forms part of the OVG limit). This is called a capped, dynamic baseline. At the time of publication of this protocol, the OVG limit is 15,000 m^3/month OR 9,000 kg CH_4/month. If/when the OVG limit changes the baseline will change to match the new limit as of the date that the new limit comes into force. This change would be effective for both new and existing projects and subprojects. If the OVG limit changes during the offset crediting period the offset project developer must update the offset project plan within 60 days to reflect the new limit. Only emission reductions that are below the OVG are eligible to generate emission offsets.

The capped dynamic baseline is measured by metering the volume of gas captured during the project condition, projected to the baseline, **or** the baseline cap, **whichever is lower**. For example:

1. **Site A** implements a vent gas capture project. The meter records 14,500 m^3/month of captured vent gas. However, the project does not capture all sources of venting on-site, and the site continues to vent 1,000 m^3/month which is reported to Petrinex. The OVG for this site is 15,000 m^3/month.

   The baseline cap for this site is: OVG – reported venting = 15,000 m^3 – 1,000 m^3 = 14,000 m^3/month.

   The metered volume of gas captured during the project condition, projected to the baseline is 14,500 m^3/month.

   The baseline for this site is the baseline cap, which is 14,000 m^3/month, because it is the lower volume.

2. **Site B** implements a vent gas capture project. The meter records 9,000 m^3/month of captured vent gas. However, the project does not capture all sources of venting on-site, and the site continues to report 1,000 m^3/month of vented gas to Petrinex. The OVG for this site is 15,000 m^3/month.

   The baseline cap for this site is: OVG – venting = 15,000 m^3 – 1,000 m^3 = 14,000 m^3/month.

   The metered volume of gas captured during the project condition, projected to the baseline is 9,000 m^3/month.

   The baseline for this site is the metered volume of captured gas, which is 9,000 m^3/month, because it is the lower volume.

3. **Site C** implements a vent gas capture project. The meter records 30,000 m^3/month of captured vent gas. All venting on-site is captured by the project and the site does not report any venting to Petrinex. The OVG for this site is 15,000 m^3/month.

   The baseline cap for this site is: OVG – venting = 15,000 m^3 – 0 m^3 = 15,000 m^3/month.

   The metered volume of gas captured during the project condition, projected to the baseline is 30,000 m^3/month.

   The baseline for this site is the baseline cap, which is 15,000 m^3/month, because it is the lower volume.

4. **Site D** implements a vent gas capture project. However, the project equipment suffers an upset and the project site is forced to vent, rather than capture, most of the gas. The meter records 3,000 m^3/month of captured vent gas. Due to the upset, the site reports 16,000 m^3/month venting to Petrinex. The OVG for this site is 15,000 m^3/month.

   The baseline cap for this site is: OVG – venting = 15,000 m^3 – 16,000 m^3 = -1,000 m^3/month.

   The metered volume of gas captured during the project condition, projected to the baseline is 3,000 m^3/month.

   The baseline for this site is the baseline cap, which is -1,000 m^3/month, because it is the lower volume. In this case, the site does not generate any emission offsets for that month. See also section 4.1.5.

Note that as compliance with the OVG may also be demonstrated via the mass limit, sites may also show compliance by converting the volume of vented gas into a mass of vented CH_4 and comparing against the mass limit of 9,000 kg CH4/month; however, the principles illustrated above remain the same. This projected baseline is dynamic so it ensures the baseline correctly accounts for the month-to-month variation in captured vent gas.

2.1 Identification of Baseline Sources and Sinks

The identification of sources and sinks (SSs) in the baseline condition is based on ISO 14064-2*: Specification with guidance at the project level for quantification, monitoring and reporting of greenhouse gas emission reductions or* removal enhancements standard. SSs are determined to be either controlled, related or affected by the project activity and are defined as follows:

Controlled: The behaviour or operation of a controlled source and/or sink is under the direction and influence of an emission offset project developer through financial, policy, management or other instruments.

Related: A related source and/or sink has material and/or energy flows into, out of or within a project but is not under the reasonable control of the emission offset project developer.

Affected: An affected source and/or sink is influenced by the project activity through changes in market demand or supply for products or services associated with the project.

All SSs were identified by reviewing the relevant process flow diagrams, consulting with technical experts and reviewing best practice guidance. This iterative process confirmed that SSs in the process flow diagrams covered the full scope of activities under this protocol.

Based on the process flow diagram provided in Figure 1, the baseline SSs were organized into life cycle categories and depicted in Figure 2. A description of each SS and its classification as controlled, related or affected is provided in Table 1.

Figure 1: Baseline Process Flow Diagram

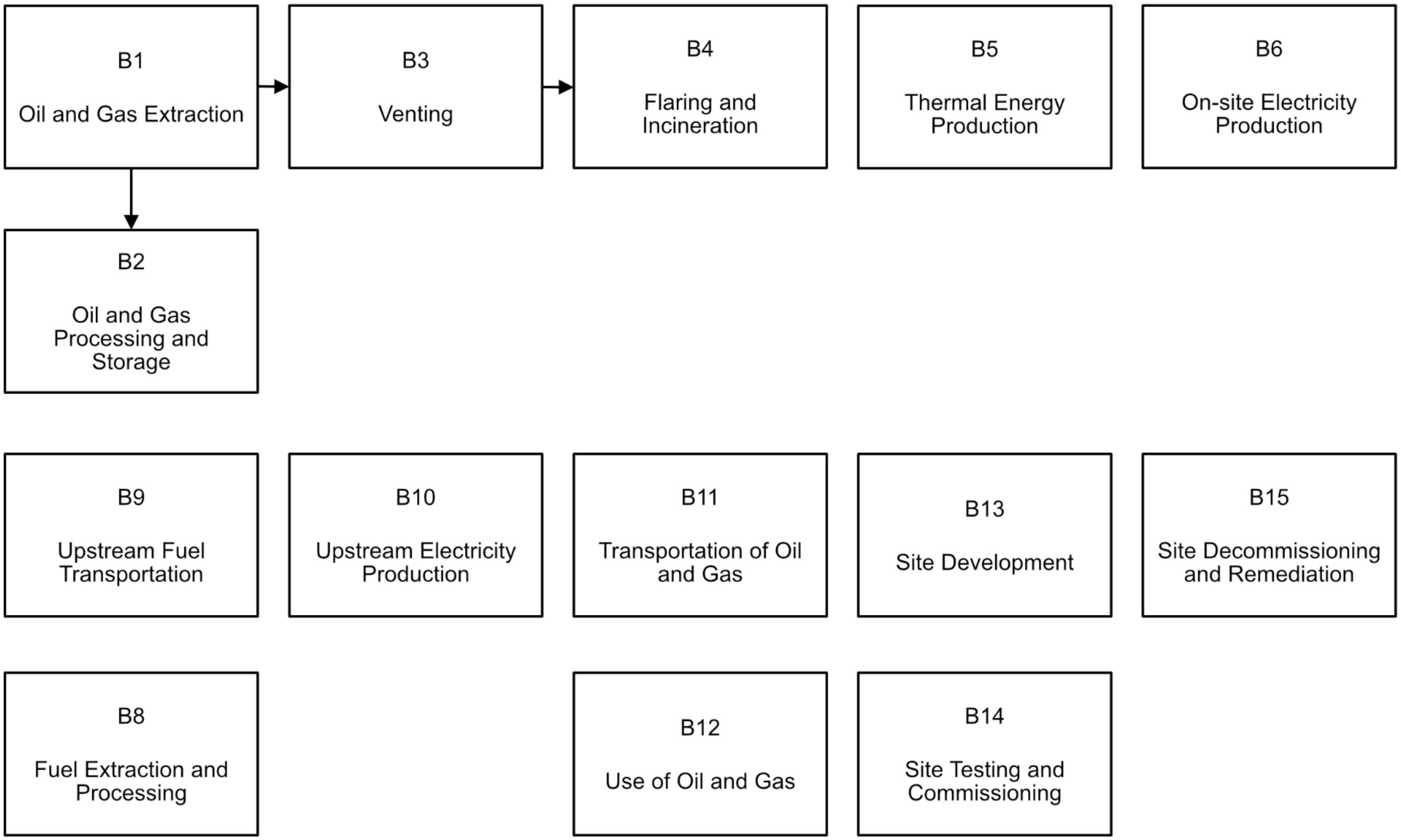

Figure 2: Baseline Condition Sources and Sinks

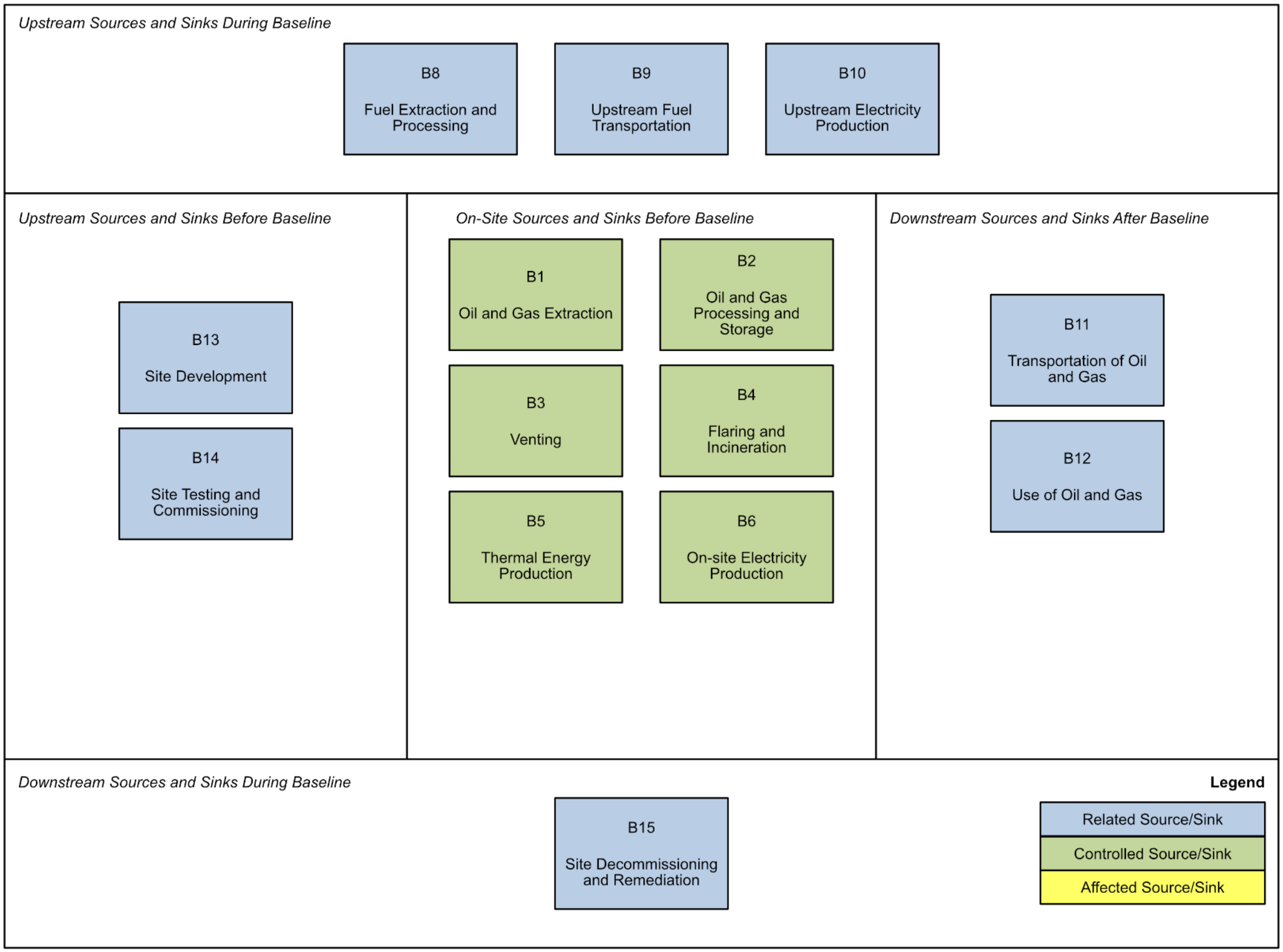

Table 1: Identification of Baseline Sources and Sinks

Sources and Sinks	Description	Controlled, Related or Affected
Upstream SSRs During Baseline		
B8 Upstream fuel extraction and processing	Fossil fuels consumed at the site will have been extracted and processed. This will result in upstream GHG emissions. Where the project is using captured gas for on-site fuel, this will be displaced.	Related
B9 Upstream fuel transportation	Fossil fuels consumed at the site will have been transported to site by pipeline or by tanker truck, for example. This will result in upstream GHG emissions. Where the project is using captured gas for on-site fuel, this will be displaced.	Related
B10 Upstream electricity production	Any electricity imported to the site will have been generated off-site. This may result in upstream GHG emissions. Where the project is using captured gas to generate power for on-site use, this will be displaced.	Related
Upstream SSs Before Baseline		
B13 Site Development	Site development will be required and may include clearing vegetation, site preparation, laying of foundations, drilling, construction of project equipment and housing, etc. The development of the site will result in GHG emissions from running development equipment and may remove sources of natural sequestration.	Related
B15 Site Testing and Commissioning	Site testing and commissioning will be required to ensure that the site equipment can be correctly and safely operated. This may involve combustion of fossil fuels, use of electricity, testing of safety venting and flare systems, etc.	Related
On-Site SSs During Baseline		
B1 Oil and gas extraction	The site will be extracting oil and/or gas. Energy consumed by the processing equipment may result in GHG emissions.	Controlled
B2 Oil and gas processing and storage	The site may include processing equipment, such as compressors, dehydrators, etc. and storage equipment, such as oil tanks. Energy consumed by this processing and storage equipment may result in GHG emissions.	Controlled
B3 Venting	The site will be venting gas direct to atmosphere. This may come from a variety of sources, such as compressor seals, tank relief valves, dehydrators, etc. This would result in direct release of CH_4 and CO_2. This is the main emissions source that will be impacted by the project.	Controlled

B4 Flaring and incineration	The site may have existing equipment for combusting gas in a flare or incinerator. This would result in GHG emissions.	Controlled
B5 Thermal energy production	The site may include existing equipment for some heat production. Energy consumed by the heat production equipment may result in GHG emissions. Where the project is using captured gas to generate heat, this may be displaced.	Controlled
B6 On-site electricity production	The site may include existing equipment for power production. Energy consumed by the power producing equipment may result in GHG emissions. Where the project is using captured gas to generate power, this may be displaced.	Controlled
On-Site SSs After Baseline		
B15 Site decommissioning and remediation	Once the site is no longer operational it will have to be safely decommissioned, and the site may need to be remediated. This may involve demolition and remedial environmental works. This work will result in GHG emissions from combustion of fossil fuels and consumption of electricity and may involve the restoration of some natural carbon sequestration ability on the site.	Related
Downstream SSs During Baseline		
B11 Downstream transportation of oil and gas	Oil and gas produced by the site will have to be transported to consumers, via pipeline, railcar, etc. These transportation systems result in GHG emissions from venting, fugitives, combustion of fossil fuels and consumption of electricity.	Related
B12 Downstream use of oil and gas	The oil and gas produced by the site will be used as a feedstock or directly as a fuel. The processing and/or use of the oil and gas will result in GHG emissions from venting, fugitives, combustion and consumption of electricity.	Related

3 Project Condition

The project condition is represented by the capture and conservation or destruction of gas that would have been vented to atmosphere in the baseline condition.

The project condition may include several components, depending on the nature of the project being implemented. This may include a capture and processing component, an on-site power and/or heat generation component, or a destruction (flaring or incineration) component. These components may require fuel and/or power to operate and emissions associated with this additional energy use must be included in the project condition.

Where the captured gas is combined with another gas stream (e.g. supplemental fuel gas for a flare), the total quantity of captured gas must be metered separately so that the quantity of captured gas can be accurately determined. As such, metering of captured gas volumes and composition must take place directly after the point of capture and upstream of any mingling or point of use. Projects with a destruction (flaring or incineration) component must be operated in accordance with manufacturer's specification and be in compliance with relevant AER Directives to generate emission offsets.

Based on the process flow diagram provided in Figure 1, the project SSs were organized into life cycle categories and depicted in Figure 4. A description of each SS and its classification as controlled, related or affected is provided in Table 2.

Figure 3: Process Flow Diagram for the Project Condition

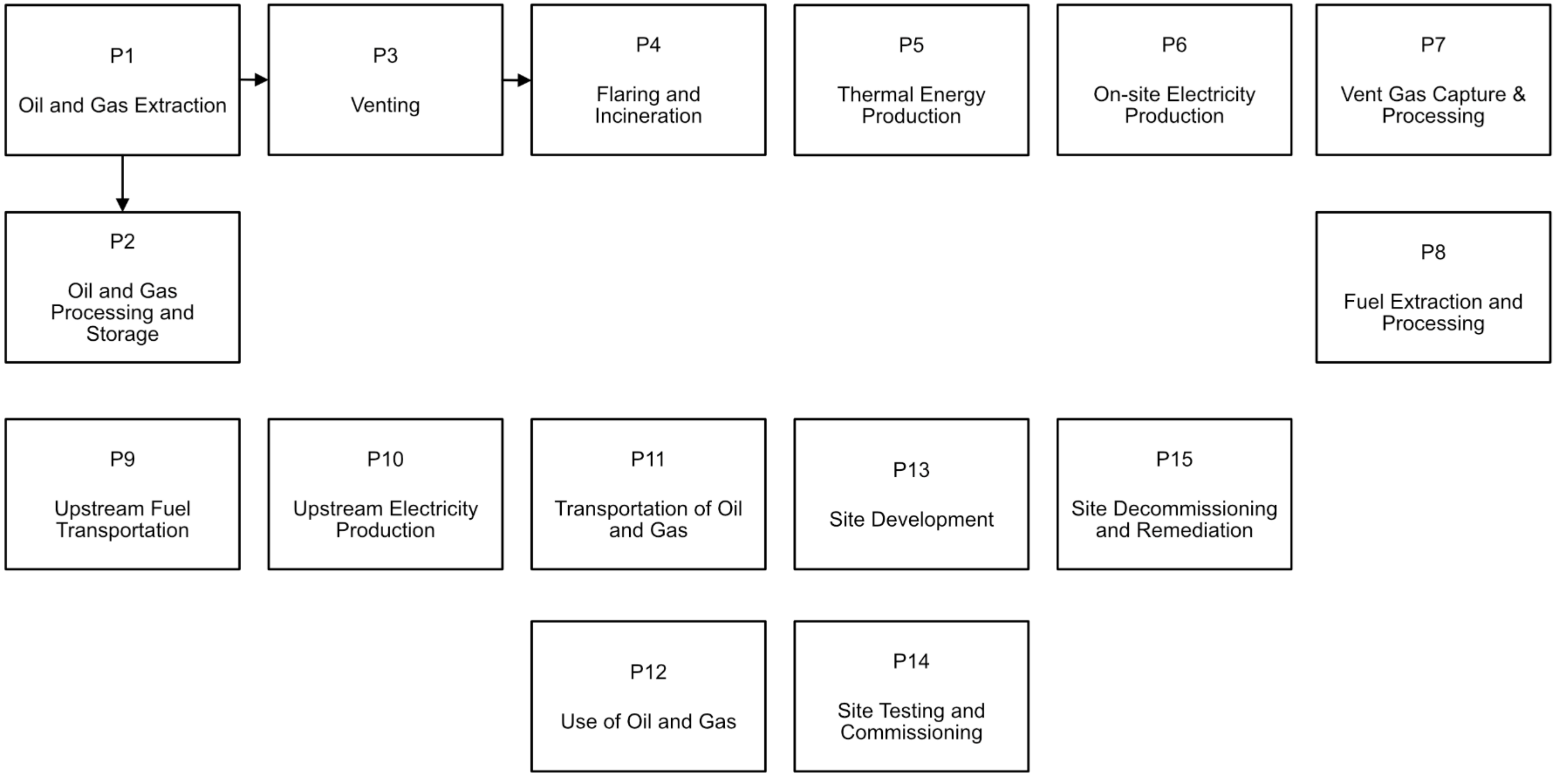

Figure 4: Project Condition SSs

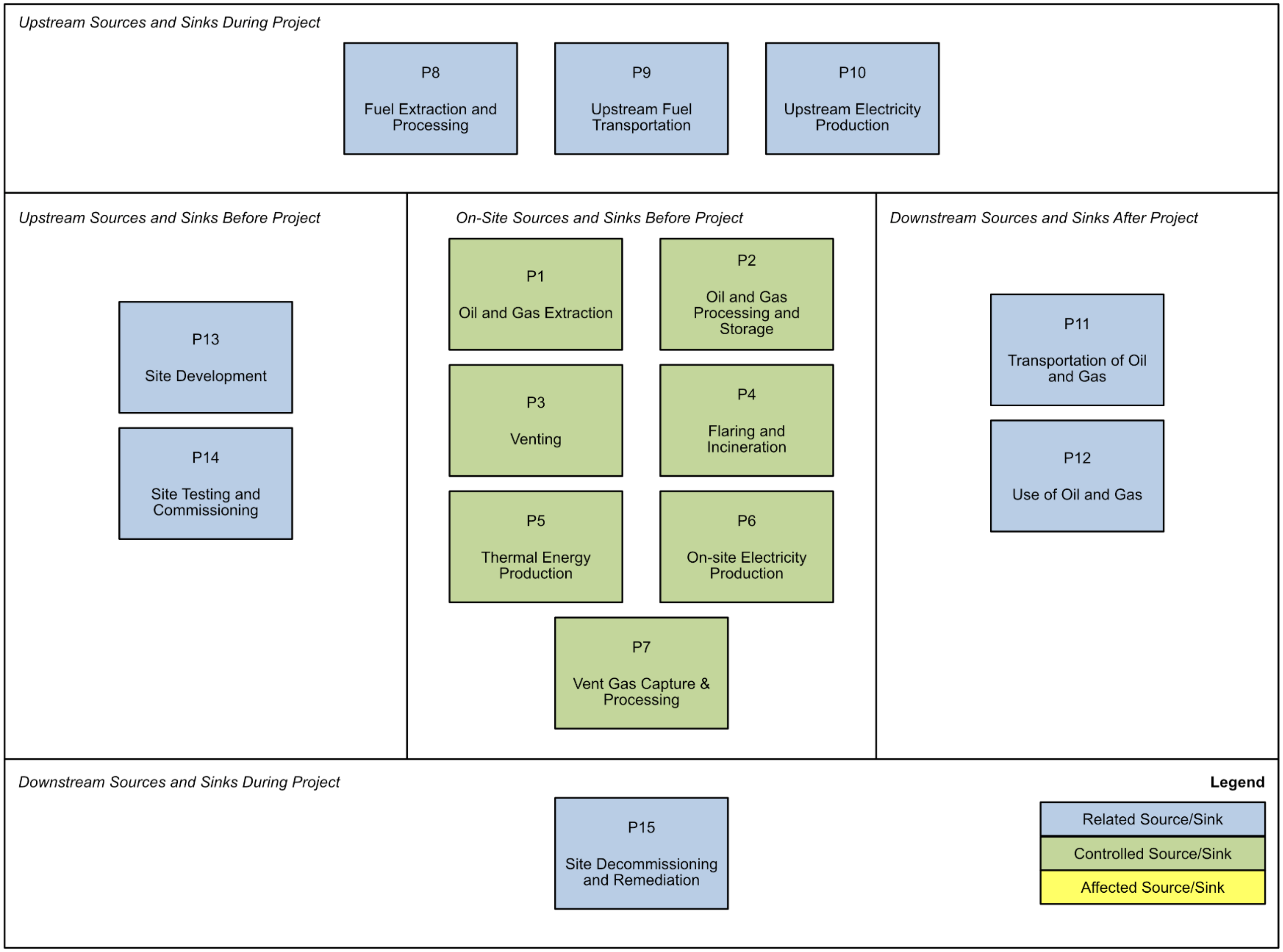

Table 2: Identification of Project Sources and Sinks

Source and Sinks	Description	Controlled, Related or Affected
Upstream SSs During the Project		
P8 Upstream fuel extraction and processing	Where the project results in additional consumption of fossil fuels to run the vent gas capture equipment (e.g. supplemental fuel gas for a flare) these will have been extracted and processed. This will result in upstream GHG emissions.	Related
P9 Upstream fuel transportation	Where the project results in additional consumption of fossil fuels to run the vent gas capture equipment (e.g. supplemental fuel gas for a flare) these will have been transported to site by pipeline or by tanker truck, for example. Alternatively fuel could be produced on-site. This may result in upstream GHG emissions.	Related
P10 Upstream electricity production	Where the project results in additional consumption of imported power (e.g. to run the vent gas capture equipment) this will have been generated off-site. This will result in upstream GHG emissions.	Related
Upstream SSs Before the Project		
P13 Site Development	Site development will be required and may include clearing vegetation, site preparation, laying of foundations, drilling, construction of project equipment and housing, etc. The development of the site will result in GHG emissions from running development equipment and may remove sources of natural sequestration.	Related
P14 Site Testing and Commissioning	Site testing and commissioning will be required to ensure that the site equipment can be correctly and safely operated. This may involve combustion of fossil fuels, use of electricity, testing of safety venting and flare systems, etc.	Related
On-Site SSs During the Project		
P1 Oil and gas extraction	The site will be extracting oil and/or gas. Energy consumed by the extraction equipment may result in GHG emissions.	Controlled
P2 Oil and gas processing and storage	The site may include processing equipment, such as compressors and dehydrators and storage equipment, such as oil tanks. Energy consumed by this processing and storage equipment may result in GHG emissions.	Controlled
P3 Venting	Although the site will be implementing vent gas capture, venting may nonetheless occur during periods of upset in the implemented project and/or may continue to occur from vent gas sources that are not included in the project scope	Controlled
P4 Flaring and incineration	The project may direct captured vent gas to existing or new equipment for destruction. Energy consumed by the destruction equipment and burning of the vent gas will result in GHG	Controlled

	emissions. This would include supplemental fuel gas added to ensure complete combustion, and pilot fuel gas.	
P5 Thermal energy production	The project may direct captured vent gas to existing or new equipment for heat production. Energy consumed by the heat production system and combustion of the vent gas will result in GHG emissions.	Controlled
P6 On-site electricity production	The project may direct captured vent gas to existing or new equipment for power production. Energy consumed by the power production system and combustion of the vent gas will result in GHG emissions.	Controlled
P7 Vent gas capture & processing	The project equipment used to capture and/or process the vented gas may consume power and/or fossil fuels, causing GHG emissions.	Controlled
On-Site SSs After Project		
P15 Site decommissioning and remediation	Once the site is no longer operational it will have to be safely decommissioned, and the site may need to be remediated. This may involve demolition and remedial environmental works. This work will result in GHG emissions from combustion of fossil fuels and consumption of electricity and may involve the restoration of some natural carbon sequestration ability on the site.	Related
Downstream SSs During Project		
P11 Downstream transportation of oil and gas	Oil and gas produced by the site will have to be transported to consumers, via pipeline, railcar, etc. These transportation systems result in GHG emissions from venting, fugitives, combustion of fossil fuels and consumption of electricity. Where projects involve conservation of gas for pipeline injection, this conserved gas will be sent downstream and add to the emissions from this source.	Related
P12 Downstream use of oil and gas	The oil and gas produced by the site will be used as a feedstock or directly as a fuel. The processing and/or use of the oil and gas will result in GHG emissions from venting, fugitives, combustion and consumption of electricity. Where projects involve conservation of gas for pipeline injection, this conserved gas will be sent downstream and add to the emissions from this source.	Related

4 Quantification

Baseline and project conditions were assessed against each other to determine the scope for vent gas reduction quantified under this protocol. SSs are either included or excluded depending on how they are impacted by the project activity. SSs that are not expected to change between baseline and project condition – because they will occur at the same magnitude and emission rate during the baseline and project, are functionally equivalent or are not impacted by the project activity – are excluded from the quantification.

Emissions that increase or decrease as a result of the project may be included and associated greenhouse gas emissions are therefore quantified as part of the project.

All SSs are identified in Table 3 as included or excluded with justification for the approach taken.

Table 3: Comparison of Sources and Sinks

Identified SSs		Baseline (C,R,A)		Project (C,R,A)	Include or Exclude from Quantification	Justification
	Upstream SSs					
B13	Site Development	Related		N/A	Exclude	Functionally equivalent between project and baseline.
P13		N/A		Related	Exclude	
B14	Site Testing and Commissioning	Related		N/A	Exclude	Functionally equivalent between project and baseline.
P14		N/A		Related	Exclude	
B8	Upstream fuel extraction and processing	Related		N/A	**Include**	Included as captured vent gas may displace fossil fuel use in the baseline (as quantified under B5 or B6).
P8		N/A		Related	**Include**	Included as the project may require the use of additional fossil fuels to operate (as quantified under P4, P5, P6 and/or P7).
B9	Upstream fuel transportation	Related		N/A	Exclude	This source is excluded as it is assessed to be negligible.
P9		N/A		Related	Exclude	
B10	Upstream electricity production	Related		N/A	**Include**	Included as captured vent gas may displace imported electricity use in the baseline.
P10		N/A		Related	**Include**	Included as the project may require the use of additional imported electricity to operate.
	On-site SSs					
B1	Oil and gas extraction	Controlled		N/A	Exclude	Functionally equivalent between project and baseline.
P1		N/A		Controlled	Exclude	

Identified SSs		Baseline (C,R,A)		Project (C,R,A)	Include or Exclude from Quantification	Justification
B2	Oil and gas processing and storage	Controlled		N/A	Exclude	Functionally equivalent between project and baseline.
P2		N/A		Controlled	Exclude	
B3	Venting	Controlled		N/A	**Include**	Included as the objective of the projects implemented under this protocol is to reduce venting gas. To be clear, B3 represents gas that would have been vented in the absence of the project.
P3		N/A		Controlled	Exclude	This source is excluded as it would be unchanged between the baseline and project i.e. any project level venting would also be released during the baseline. However, the impact of project venting is included within the quantification of B3 as the term $Vol_{Metered}$ to ensure regulatory additionality of B3 is maintained.
B4	Flaring and incineration	Controlled		N/A	Exclude	Baseline flaring activity is excluded from the scope of the Protocol.
P4		N/A		Controlled	**Include**	Included as captured vent gas may be sent to a combustion device for destruction. For projects that include the installation of a new destruction device this will also include gas used as pilot gas, purge gas or supplemental fuel. For projects that are tying into an existing destruction device it is assumed that emissions from pilot, purge gas or supplemental fuel are the same in the baseline and the project and can be excluded.
B5	Thermal energy production	Controlled		N/A	**Include**	Included as captured vent gas may displace fossil fuel use for on-site thermal energy production in the baseline.
P5		N/A		Controlled	**Include**	Included as the captured vent gas may be used for on-site thermal energy production.
B6	On-site electricity production	Controlled		N/A	**Include**	Included as captured vent gas may displace on-site generated electricity in the baseline.
P6		N/A		Controlled	**Include**	Included as the captured vent gas may be used for on-site electricity production.

Identified SSs		Baseline (C,R,A)		Project (C,R,A)	Include or Exclude from Quantification	Justification
P7	Vent gas capture and processing	N/A		Controlled	**Include**	Included as the equipment used to capture and process the vent gas may require imported electricity and/or the use of fossil fuels to operate.
	Downstream SSs					
B11	Downstream transportation of oil and gas	Related		N/A	Exclude	Functionally equivalent between project and baseline.
P11		N/A		Related	Exclude	
B12	Downstream use of oil and gas	Related		N/A	Exclude	Functionally equivalent between project and baseline.
P12		N/A		Related	Exclude	
B15	Site decommissioning and remediation	Related		N/A	Exclude	Functionally equivalent between project and baseline.
P15		N/A		Related	Exclude	

4.1 Quantification Methodology

The quantification methodology includes net emission reductions, offset-eligible emission reductions and priced emission reductions. In some projects, some SSs may be subject to a carbon price, whereas in others they may not be subject to a carbon price. The project developer will need to determine if the SS's are subject to a carbon price and whether or not to include them in offset-eligible or priced emission reductions, depending on the nature of the project implemented and the regulatory status of the site at which the project is implemented. This is discussed further in Section 4.1.2 and Table 4. Regardless, quantification of included sources and sinks for each greenhouse gas emissions must be completed using the methodologies outlined in Table 5. The results will be used to complete the equations below for net emission reductions, offset-eligible emission reductions and priced emission reductions.

Different project types will have different sources and sinks included depending on the emission reduction activity.

4.1.1 Net Emission Reductions

Net emissions reductions are the reductions resulting from a comparison of project and baseline emissions for all SSs included in the quantification. In cases where the SS is subject to a carbon price, the emission from the SS is quantified and reported but does not contribute to the offset-eligible emission reduction calculation in section 4.1.2. Net emission reductions must be calculated using the equation below:

$$\textbf{Net Emission Reductions} = \textbf{Emissions}_{\textbf{Baseline}} - \textbf{Emissions}_{\textbf{Project}}$$

Where baseline emissions are:

$$\textbf{Emissions}_{\textbf{Baseline}} = \text{Emissions}_{\text{Venting}} + \text{Emissions}_{\text{Thermal Energy Production}} + \text{Emissions}_{\text{On-site Electricity Production}} + \text{Emissions}_{\text{Upstream Fuel Extraction \& Processing}} + \text{Emissions}_{\text{Upstream Electricity Production}}$$

Baseline emissions sources including the following:

$\text{Emissions}_{\text{Baseline}}$	=	sum of the emissions under the baseline condition
	+	emissions under B3 Venting
	+	emissions under B5 Thermal Energy Production
	+	emissions under B6 On-site Electricity Production
	+	emissions under B8 Upstream Fuel Extraction & Processing
	+	emissions under B10 Upstream Electricity production

Where project emissions are calculated according to the following:

$$\textbf{Emissions}_{\textbf{Project}} = \text{Emissions}_{\text{Venting}} + \text{Emissions}_{\text{Flaring and Incineration}} + \text{Emissions}_{\text{Thermal Energy Production}} + \text{Emissions}_{\text{On-site Electricity Production}} + \text{Emissions}_{\text{Vent gas capture and processing}} + \text{Emissions}_{\text{Upstream Fuel Extraction \& Processing}} + \text{Emissions}_{\text{Upstream Electricity Production}}$$

Project emission sources including the following:

$\text{Emissions}_{\text{Project}}$	=	sum of the emissions under the project condition
	+	emissions under P4 Flaring and Incineration
	+	emissions under P5 Thermal Energy Production
	+	emissions under P6 On-site Electricity Production

+ emissions under P7 Vent Gas Capture and Processing

+ emissions under P8 Upstream Fuel Extraction & Processing

+ Emissions under P10 Upstream Electricity Production

4.1.2 Offset Eligible Emission Reductions

Reductions of emissions that are not subject to a carbon price are eligible for emission offsets; reductions of emissions that are subject to a carbon price are not eligible for emission offsets. Projects (and subprojects) that quantify offset eligible emission reductions must also quantify and report on priced emission reductions as per section 4.1.3.

Offset eligible emission reductions are calculated from a comparison of project and baseline emissions for all sources and sinks excluding emissions that are subject to a carbon price. Some emissions such as P4 Flaring and Incineration B5/P5 Thermal Energy Production, B6/P6 On-site Electricity Production, B10/P10 Upstream Electricity Production may be subject to a carbon price in some scenarios and not in others.

- For conventional oil and gas sites that are designated under TIER as an aggregate facility:
  - Stationary fuel combustion emissions are subject to a carbon price. As such, the emissions from B5/P5 and B6/P6 are subject to a carbon price and so must be reported under *priced emission reductions*, not included under *offset eligible* emission reductions.
  - Flaring and incineration emissions (P4) and Upstream Electricity Production (B10/P10) are not subject to a reduction requirement. As such, emissions from these SSs are not currently subject to a carbon price and therefore must be included under *offset eligible emission reductions*, not included *under priced emission reductions.*
- For oil and gas sites not regulated under TIER as an aggregate facility and subject to any carbon price, the emissions from P4, B5/P5, B6/P6 and B10/P10 are all subject to a carbon price and must be reported under *priced emission reductions*, not included under *offset eligible emission reductions*.

Table 4 outlines five scenarios and shows which baseline sources and sinks would likely be included for a variety of scenarios. Sources and sinks that may be subject to a carbon price are marked with a footnote. This Table is provided for illustrative guidance only and it is the responsibility of the project developer to ensure that all appropriate SSs for their project are included and that SSs that are subject to a carbon price are not included in the quantification of offset eligible emission reductions.

Table 4: Applicable project scenarios and appropriate baseline and project sources and sinks

Scenario (Project Condition)	Baseline SSs	Project SSs
Category 1 Project Examples		
1. Vent gas capture for injection into a pipeline	B3 Venting	P7 Vent Gas Capture and Processing + P8 Upstream fuel extraction & processing
2. Vent gas capture for on-site heat production displacing existing use of fossil fuels for on-site heat production	B3 Venting + B5 Thermal Energy Production[1] + B8 Upstream Fuel Extraction & Processing	P5 Thermal Energy Production[1] P7 Vent Gas Capture and Processing + P8 Upstream Fuel Extraction & Processing
3. Vent gas capture for on-site power	B3 Venting +	P6 On-site Electricity Production[1] +

[1] May be subject to a carbon price. Where this is the case, SS is not included in offset eligible emission reductions.

Scenario (Project Condition)	Baseline SSs	Project SSs
production displacing imported electricity	B10 Upstream Electricity Production[1]	P7 Vent Gas Capture and Processing + P8 Upstream Fuel Extraction & Processing
4. Vent gas capture for on-site power production displacing existing use of fossil fuels for on-site power production	B3 Venting + B6 On-site Electricity Production[1] + B8 Upstream Fuel Extraction & Processing	P6 On-site Electricity Production[1] + P7 Vent Gas Capture and Processing + P8 Upstream Fuel Extraction & Processing
Category 2 Project Example		
5. Vent gas capture for on-site destruction in an incinerator or existing flare	B3 Venting	P4 Flaring and Incineration[1] P7 Vent Gas Capture and Processing + P8 Upstream Fuel Extraction & Processing

Offset Eligible Emission Reductions = Emissions $_{\text{Non-priced Baseline}}$ – Emissions $_{\text{Non-priced Project}}$

Where offset eligible baseline emissions are:

Emissions $_{\text{Non-priced Baseline}}$ = Emissions $_{\text{Venting}}$ + Emissions $_{\text{Thermal Energy Production}}$ + Emissions $_{\text{On-site Electricity Production}}$

Baseline emissions sources including the following:

Emissions $_{\text{Non-priced Baseline}}$ = sum of the emissions under the baseline condition that are not subject to a carbon price

\+ emissions under B3 Venting

\+ emissions under B5 Thermal Energy Production[1]

\+ emissions under B6 On-site Electricity Production[1]

Where project emissions are calculated according to the following:

Emissions $_{\text{Non-priced Project}}$ = Emissions $_{\text{Venting}}$ + Emissions $_{\text{Flaring and Incineration}}$ + Emissions $_{\text{Thermal Energy Production}}$ + Emissions $_{\text{On-site electricity production}}$ + Emissions $_{\text{Vent Gas Capture and Processing}}$

Project emission sources including the following:

Emissions $_{\text{Non-priced Project}}$ = sum of the emissions under the project condition that are not subject to a carbon price

+ emissions under P4 Flaring and Incineration[1]

+ emissions under P5 Thermal Energy Production[1]

+ emissions under P6 On-site Electricity Production[1]

+ emissions under P7 Vent Gas Capture and Processing

4.1.3 Priced Emission Reductions

Emissions that are subject to a carbon price are not eligible for emission offsets. Projects (and subprojects) must quantify and report on reductions of emissions that are subject to a carbon price.

Priced emission reductions are calculated from a comparison of project and baseline emissions for all sources and sinks.

Priced emission reductions are calculated from a comparison of project and baseline emissions for all SSs that are subject to a carbon price. Some emissions such as P4 Flaring and Incineration B5/P5 Thermal Energy Production, B6/P6 on-site electricity production, may be subject to a carbon price in some scenarios and not in others. It is the responsibility of the emission offset project developer to ensure that SSs that are subject to a carbon price are included in the quantification of priced emission reductions. See Section 4.1.2 for more information on SSs subject to a carbon price.

$$\textbf{Priced Emission Reductions} = \textbf{Emissions}_{\textbf{Priced Baseline}} - \textbf{Emissions}_{\textbf{Priced Project}}$$

Where priced baseline emissions are:

$$\textbf{Emissions}_{\textbf{Priced Baseline}} = \text{Emissions}_{\text{Thermal Energy Production}} + \text{Emissions}_{\text{On-site Electricity Production}}$$

Baseline emissions sources including the following:

Emissions $_{\text{Priced Baseline}}$ = sum of the emissions under the baseline condition that are subject to a carbon price

+ emissions under B5 Thermal Energy Production[1]

+ emissions under B6 On-site Electricity Production[1]

Where project emissions are calculated according to the following:

$$\textbf{Emissions}_{\textbf{Priced Project}} = \text{Emissions}_{\text{Flaring and Incineration}} + \text{Emissions}_{\text{Thermal Energy Production}} + \text{Emissions}_{\text{On-site Electricity Production}}$$

Project emission sources including the following:

Emissions $_{\text{Priced Project}}$ = sum of the emissions under the project condition that are subject to a carbon price

+ emissions under P4 Flaring and Incineration[1]

+ emissions under P5 Thermal Energy Production[1]

+ emissions under P6 On-site Electricity Production[1]

4.1.4 Total Vented Reduction

Project developers must quantify and report on total vented reductions resulting from the implementation of the project. Total vented reductions in tonnes of carbon dioxide equivalent are calculated from the metered volume of previously vented gas, as follows:

$$Emissions_{Total\ Vented\ Reductions} = (Vol._{Metered} * \%\ CO_2 * \rho_{CO2}) + [(Vol._{Metered} * \%\ CH_4 * \rho_{CH4}) * GWP_{CH4}]$$

4.1.5 Negative “VolGasVented” During a Calendar Month

Should a project or sub-project vent more gas than allowed by the OVG (or DVG or CBFA, as applicable) during a calendar month, that project or sub-project may calculate a negative value for the term “VolGasVented” under SS B3. Where this occurs, the project or sub-project will calculate a negative value for the term “EmissionsVenting” under SS B3. This must be reported as a negative value for that month (i.e. this will reduce the Net Emissions Reductions for the reporting period in which this month occurs).

4.1.6 Time Period for Calculations

As additionality is assessed against the vented gas volume/vented CH_4 mass limits of D060, and these limits are set on a calendar month basis, all calculations must be completed on a calendar month basis. To be clear, Net Emissions Reductions, Offset Eligible Emissions Reductions, Priced Emissions Reductions and Total Vented Reductions must be calculated per calendar month, as well as per reporting period.

Table 5: Quantification Procedures

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
Project SSs						
P4 Flaring and Incineration	$Emissions_{Flaring\ and\ Incineration} = (Vol._{Gas\ Flaring} * EF\ CO_2) + (Vol._{Gas\ Flaring} * \%\ CH_4 * \rho_{CH4} * (1 - DE) * GWP_{CH4}) + (Vol._{Gas\ Flaring} * EF\ N_2O * GWP_{N2O}) + (Vol._{Supplemental\ Gas} * EF\ CO_2) + (Vol._{Supplemental\ Gas} * \%\ CH_4 * \rho_{CH4} * (1 - DE) * GWP_{CH4}) + (Vol._{Supplemental\ Gas} * EF\ N_2O * GWP_{N2O})$					
	$Emissions_{Flaring\ and\ Incineration}$	tonnes CO_2e	N/A	N/A	N/A	Calculation of emissions from project flare, incinerator or combustor.
	Volume of Captured Vent Gas Destroyed in Flare or Incinerator / $Vol._{Gas\ Flaring}$	e^3m^3	Measured	Online metering of volume of captured vent gas that is sent to flare or incinerator. Correlate to operational hours of flare or incinerator.	Continuous metering, daily polling	Online metering is standard practice in the Quantification Methodologies.
	Volume of Supplemental Gas to operate flare or incineration equipment at STP[2]. Pilot purge and/or supplemental fuel / Vol. Supplemental Gas	e^3m^3 at STP	Measured or Estimated	Online metering of volume of gas used to operate the flare or incinerator (pilot/purge/supplemental fuel). If offline metering of volume of gas used to operate the flare or incinerator use method in Alberta Quantification Methodology	Continuous metering, daily polling Weekly	Online and offline metering is outlined in the Quantification Methodologies.
	Methane Composition of Vent Gas / % CH_4	%	Measured	Direct Measurement as outlined in Directive 017. Measurement of the concentration must be representative of the captured gas stream that was being vented in the baseline. Alternatively, if this is not available, use the default value for rich gas from the Alberta Greenhouse Gas Quantification Methodologies.	Annual	Direct measurement is the most accurate. Gas composition is typically reasonably stable and annual provides sufficient accuracy. Defaults are conservative and accepted in the Alberta Greenhouse Gas Quantification Methodologies.

[2] STP (Standard Temperature and Pressure) is defined in this protocol as 15°C and 101.3 kPa.

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Density of CH_4 / ρ_{CH4}	kg/m^3	Constant	0.6785 kg/m^3 at STP	N/A	Accepted value as per Alberta Greenhouse Gas Quantification Methodologies.
	Destruction Efficiency of Flare or Incinerator / DE	%	Estimated	Field measured destruction efficiency OR, if this is not available, use manufacturer's specifications OR, if this is not available, use default methane destruction efficiency for unassisted flares in the Alberta Greenhouse Gas Quantification Methodologies	Once	Field measured destruction efficiency will be most accurate and relevant, but many sites will not have this data. Where manufacturer's specifications are available, these will be also be relevant. If neither is available, the unassisted flare defaults from the Alberta Greenhouse Gas Quantification Methodologies are conservative.
	Emission Factor for CO_2 / EF_{CO2}	tonnes CO_2/e^3m^3	Estimated	Site specific, calculated based on gas analysis using the procedures in Appendix C, Section C.1. of the Quantification Methodologies. Alternatively, if this is not available, use the default value for rich gas for the appropriate device type (unassisted flare, assisted flare or incinerator) from the Flaring Chapter of the Alberta Greenhouse Gas Quantification Methodologies.	Annual	Direct measurement will be the most accurate. Gas composition is typically reasonably stable and annual provides sufficient accuracy. Defaults are as accepted in the Alberta Greenhouse Gas Quantification Methodologies.
	Emission Factor for N_2O / EF_{N2O}	tonnes N_2O/e^3m^3	Estimated	Use the default N_2O emission factor for flaring hydrocarbon gas from the Flaring Chapter of the Alberta Greenhouse Gas Quantification Methodologies.	Annual	Accepted value as per Quantification Methodologies (note this does not vary by flare/incinerator device type).

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Global Warming Potential / $GWP_{CH4, N2O}$	Unitless	Estimated	As per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard.
P5 Thermal Energy Production, P6 On-site Electricity Production, P7 Vent Gas Capture and Processing	$Emissions_{ProjectEquipment} = Emissions_{OnSiteFuelUse} + Emissions_{OnSiteElecUse}$ Where: $Emissions_{OnSiteFuelUse} =$ $[\Sigma (Vol.\ Fuel\ i * EF\ Fuel\ i_{CO2}) +$ $\Sigma (Vol.\ Fuel\ i * EF\ Fuel\ i_{CH4} * GWP_{CH4}) +$ $\Sigma (Vol.\ Fuel\ i * EF\ Fuel\ i_{N2O} * GWP_{N2O})]$ $/ 1000 / 1000$ And: $Emissions_{OnSiteElecUse} =$ $Elec * EF\ Elec_{CO2e}$					
	$Emissions_{ProjectEquipment}$	tonnes CO_2e	N/A	N/A	N/A	Calculation of emissions from running project equipment
	$Emissions_{OnSiteFuelUse}$	tonnes CO_2e	N/A	N/A	N/A	Calculation of emissions from fuel used for project equipment
	$Emissions_{OnSiteElecUse}$	tonnes CO_2e	N/A	N/A	N/A	Calculation of emissions from power used for project equipment
	Volume of Each Type of Fuel used on-site for thermal energy production, on-site electricity production and/or to run vent gas capture and	L, m^3 , or other	Measured	Direct metering or reconciliation of volume in storage (including volumes received) of incremental fuels used for thermal energy production, electricity production or vent gas capture system. Where the individual equipment is not directly metered, fuel consumption may be estimated based on metered site-	Continuous metering or monthly reconciliation.	Both methods are standard practise. Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence.

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	processing systems / Vol Fuel i			wide fuel consumption and appropriate engineering calculations of the proportionate share of fuel consumed by the project system in accordance with Equation C7-1 of the Alberta Greenhouse Gas Quantification Methodologies.		
	Electricity produced and used on-site for thermal energy production, on-site electricity production and/or to run vent gas capture and processing systems / Elec	MWh	Measured	Direct metering of electricity used to run thermal energy production, electricity production or vent gas capture system. Where the individual equipment is not directly metered, electricity consumption may be estimated based on metered site-wide electricity consumption and appropriate engineering calculations of the proportionate share of electricity consumed by the project system in accordance with Equation C7-1 of the Alberta Greenhouse Gas Quantification Methodologies.	Continuous metering	Frequency of metering is highest level possible.
	CO_2 Emissions Factor for Each Type of Fuel / EF Fuel i $_{CO2}$	g CO_2 per L, m^3 or other	Estimated	Where the displaced fuel is gas, then this should be site specific, calculated based on gas analysis using the procedures in Appendix C, Section C.1. of the Alberta Greenhouse Gas Quantification Methodologies. Gas analysis must be representative of the captured gas stream that was being vented in the baseline. Alternatively, if this is not available, use the default value from the Quantification Methodologies. Where the displaced fuel is non-variable (for example, diesel), as per the Carbon Offset Emission Factors Handbook	Annual	Where the displaced fuel is gas, direct measurement will be the most accurate. Gas composition is typically reasonably stable and annual provides sufficient accuracy. Defaults are as accepted in the Alberta Greenhouse Gas Quantification Methodologies. Where the displaced fuel is non-variable (for example, diesel), use the relevant version of the Carbon Offset Emission Factors Handbook

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	CH_4 Emissions Factor for Each Type of Fuel / EF Fuel i $_{CH4}$	g CH_4 per L, m^3 or other	Estimated	Where the displaced fuel is gas, then this should be site specific, calculated based on gas analysis. Gas analysis must be representative of the captured gas stream that was being vented in the baseline. Alternatively, if this is not available, use the default value from the Alberta Greenhouse Gas Quantification Methodologies. Where the displaced fuel is non-variable (for example, diesel), as per the Carbon Offset Emission Factors Handbook	Annual	Where the displaced fuel is gas, direct measurement will be the most accurate. Gas composition is typically reasonably stable and annual provides sufficient accuracy. Defaults are as accepted in the Alberta Greenhouse Gas Quantification Methodologies. Where the displaced fuel is non-variable (for example, diesel), use the relevant version of the Carbon Offset Emission Factors Handbook
	N_2O Emissions Factor for Each Type of Fuel / EF Fuel i $_{N2O}$	g N_2O per L, m^3 or other	Estimated	As per the Carbon Offset Emission Factors Handbook	Annual	Use the relevant version of the Carbon Offset Emission Factors Handbook
	CO_2e Emissions Factor for Electricity / EF Elec CO_2e	tonnes CO_2e / MWh	Estimated	As per the Carbon Offset Emission Factors Handbook	Annual	Use the relevant version of the Carbon Offset Emission Factors Handbook
	Global Warming Potential / $GWP_{CH4, N2O}$	Unitless	Estimated	As per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard.
P8 Upstream Fuel Extraction and Processing	$Emissions_{Fuel\ Extraction\ \&\ Processing} = [(\Sigma (Vol.\ Fuel\ i * EF\ Fuel\ i_{CO2}) + \Sigma (Vol.\ Fuel\ i * EF\ Fuel\ i_{CH4} * GWP_{CH4}) + \Sigma (Vol.\ Fuel\ i * EF\ Fuel\ i_{N2O} * GWP_{N2O})] / 1000$					

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Emissions $_{\text{Fuel Extraction \& Processing}}$	tonnes CO_2e	N/A	N/A	N/A	Calculation of emissions associated with extraction and processing of fossil fuels used to run the project equipment
	Volume of Fuel Combusted for Flaring/Incineration Supplemental Gas and/or On-Site Thermal Energy and/or Electricity Production and/or Vent Gas Capture & Processing / $Vol._{Fuel}$	Volumes taken from P4 ($Vol._{\text{Supplemental Gas}}$), P5, P6 and/or P7				
	CO_2 Emissions Factor for Each Type of Fuel / EF Fuel i $_{CO2}$	kg CO_2 per L, m^3 or other	Estimated	As per the Carbon Offset Emission Factors Handbook	Annual	Use the relevant version of the Carbon Offset Emission Factors Handbook
	CH_4 Emissions Factor for Each Type of Fuel / EF Fuel i $_{CH4}$	kg CH_4 per L, m^3 or other	Estimated	As per the Carbon Offset Emission Factors Handbook	Annual	Use the relevant version of the Carbon Offset Emission Factors Handbook
	N_2O Emissions Factor for Each Type of Fuel / EF Fuel i $_{N2O}$	kg N_2O per L, m^3 or other	Estimated	As per the Carbon Offset Emission Factors Handbook	Annual	Use the relevant version of the Carbon Offset Emission Factors Handbook
	Global Warming Potential / $GWP_{CH4,\ N2O}$	Unitless	Estimated	As per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard.
P10 Upstream Electricity Production	$\text{Emissions}_{\text{Electricity}} = E * EF_{\text{Electricity}}$					
	$\text{Emissions}_{\text{Electricity}}$	tonnes CO_2e	N/A	N/A	N/A	Calculation of emissions associated with production, transmission and distribution of electricity used to run site equipment

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
						in the absence of the fuel and/or power provided by the project equipment
	Electricity / E	MWh	Measured	Direct metering	Continuous metering	Standard practise. Frequency of metering is highest level possible.
	Emissions Factor for Electricity / $EF_{Electricity}$	t CO_2e per MWh	Estimated	As per the Carbon Offset Emission Factors Handbook	Annual	Use the relevant version of the Carbon Offset Emission Factors Handbook. Emission Factor includes line losses.
Baseline SSs						
B3 Venting	**Volume Method A** $Emissions_{Venting} =$ $(Vol._{GasVented} * \% CO_2 * \rho_{CO2}) +$ $(Vol._{GasVented} * \% CH_4 * \rho_{CH4} * GWP_{CH4})$ Where: IF $Vol_{Metered} + Vol_{ReportedVenting} < Vol_{Cap}$ THEN $Vol_{GasVented} = Vol_{Metered}$ ELSE $Vol_{GasVented} = Vol_{Cap} - Vol_{Reported\ Venting}$ AND Where: Vol_{Cap} = OVG, OR *For Flexibility Mechanism 1*, DVG **OR** **Mass Method B** $Emissions_{Venting} =$ $(Vol._{GasVented} * \% CO_2 * \rho_{CO2}) +$ $(Mass._{CH4Vented} * GWP_{CH4})$					

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Where: IF $Mass_{Metered} + Mass_{ReportedVenting} < Mass_{Cap}$ THEN $Mass._{CH4Vented} = Mass_{Metered}$ ELSE $Mass._{CH4Vented} = Mass_{Cap} - Mass_{Reported\ Venting}$ AND Where: $Mass_{Cap}$ = OVG, OR *For Flexibility Mechanism 1*, DVG					
	Emissions $_{Venting}$	tonnes CO_2e	N/A	N/A	N/A	Calculation of emissions vented during baseline that are now captured by the project equipment. OVG (or DVG or CBFA) is a monthly limit, so parameter should be calculated monthly.
	Volume of Gas Vented / $Vol._{Gas\ Vented}$	e^3m^3	Estimated	Calculated. IF $Vol_{Metered} + Vol_{ReportedVenting} < Vol_{Cap}$ THEN $Vol._{GasVented} = Vol_{Metered}$ ELSE $Vol._{GasVented} = Vol_{Cap} - Vol_{Reported\ Venting}$	N/A	Calculation of volume of vented gas that is additional. OVG (or DVG or CBFA) are monthly limits, so parameter should be calculated monthly.
	Mass of CH_4 Vented / $Mass._{CH4Vented}$	tonnes CH_4	Estimated	Calculated. IF $Mass_{Metered} + Mass_{ReportedVenting} < Mass_{Cap}$ THEN $Mass._{CH4Vented} = Mass_{Metered}$ ELSE $Mass._{CH4Vented} = Mass_{Cap} - Mass_{Reported\ Venting}$	N/A	Calculation of mass of vented CH_4 that is additional. OVG (or DVG are monthly limits, so parameter should be calculated monthly.
	Volume of Previously Vented Gas Captured by Project Equipment / $Vol_{Metered}$	e^3m^3	Measured	Direct metering	Continuous metering, reconciled monthly.	Highest possible accuracy. Required to establish accurate calculations and functional equivalence. OVG (or DVG or CBFA) is a monthly limit, so parameter should be calculated monthly and corrected to STP.

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Mass of Previously Vented CH_4 Captured by Project Equipment / $Mass_{Metered}$	tonnes CH_4	Calculated	Calculated: $Mass_{Metered} = Vol_{Metered} * \% \, CH_4 * \rho_{CH4}$	Monthly	Required to establish accurate calculations and functional equivalence. OVG (or DVG) is a monthly limit, so parameter should be calculated monthly.
	Volume of Gas Reported as Vented in the Project Condition / $Vol_{ReportedVenting}$	e^3m^3	Estimated	As reported to AER as VENT volumes via Petrinex	Monthly	Industry standard practice.
	Mass of CH_4 Reported as Vented in the Project Condition / $Mass_{ReportedVenting}$	tonnes CH_4	Calculated	Calculated: $Mass_{ReportedVenting} = Vol_{ReportedVenting} * \% \, CH_4 * \rho_{CH4}$	Monthly	Industry standard practice.
	Volume Cap on Vented Gas Emissions Established by Directive 060 / Vol_{Cap}	e^3m^3	N/A	N/A	Monthly	Established by Directive D060 on a monthly basis by the Overall Vent Gas (OVG) Limit, or by the Defined Vent Gas (DVG) Limit (Flexibility Mechanism 1) or by the Crude Bitumen Fleet Average (CBFA) (Flexibility Mechanism 2)
	Mass Cap on Vented Methane Emissions Established by Directive 060 / Vol_{Cap}	tonnes CH_4	N/A	N/A	Monthly	Established by Directive D060 on a monthly basis by the Overall Vent Gas (OVG) Limit, or by the Defined Vent Gas (DVG) Limit (Flexibility Mechanism 1)
	Carbon Dioxide Composition of Vent Gas / % CO_2	%	Measured	Direct Measurement as outlined in *Directive 017*. Must be representative of the captured gas stream that was being vented in the baseline.	Annual	Direct measurement will be the most accurate. Gas composition is typically reasonably stable and annual provides sufficient

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
				Alternatively, if this is not available, use the default value for rich gas from the Alberta Greenhouse Gas Quantification Methodologies.		accuracy. Defaults are as accepted in the Alberta Greenhouse Gas Quantification Methodologies.
	Methane Composition of Vent Gas / % CH_4	%	Measured	Direct Measurement as outlined in *Directive 017*. Must be representative of the captured gas stream that was being vented in the baseline. Alternatively, if this is not available, use the default value for rich gas from the Alberta Greenhouse Gas Quantification Methodologies.	At least Annual	Direct measurement will be the most accurate. Gas composition is typically reasonably stable and annual provides sufficient accuracy. Defaults are as accepted in the Alberta Greenhouse Gas Quantification Methodologies.
	Density of CH_4 / ρ_{CH4}	kg/m^3	Constant	0.6785 kg/m^3 at STP	N/A	Accepted value as per Alberta Greenhouse Gas Quantification Methodologies
	Density of CO_2 / ρ_{CO2}	kg/m^3	Constant	1.861 kg/m^3 at STP	N/A	Accepted value as per Alberta Greenhouse Gas Quantification Methodologies
	Global Warming Potential / GWP_{CH4}	Unitless	Estimated	As per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard.
	Emissions $_{On\text{-}SiteFuelUse}$ = [Σ (Vol. Fuel i * EF Fuel i_{CO2}) + Σ (Vol. Fuel i * EF Fuel i_{CH4} * GWP_{CH4}) +					

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
B5 Thermal Energy Production, B6 On-site Electricity Production	Σ (Vol. Fuel i * EF Fuel i_{N2O} * GWP_{N2O})] / 1000 / 1000 Where: Vol. Fuel i = ($Vol_{Metered}$ * $HHV_{VentGas}$) / HHV Fuel i					
	Emissions $_{On-SiteFuelUse}$	tonnes CO_2e	N/A	N/A	N/A	Calculation of emissions from fuel used to run site equipment in the absence of the fuel and/or power provided by the project equipment
	Volume of each type of displaced fuel used on-site for thermal energy production, on-site electricity production in the absence of the project / Vol Fuel i	L, m^3 or other	Calculated	Calculated on an energy equivalent basis based on vent gas captured in B3 and used to generate electricity/heat on-site. , as per Vol. Fuel i = ($Vol_{Metered}$ * $HHV_{VentGas}$) / HHV $_{Fuel\ i}$	Monthly	Vent Gas Volumes are calculated monthly.
	Volume of Previously Vented Gas Captured by Project Equipment / $Vol_{Metered}$	e^3m^3	Measured	Taken from B3.	Continuous metering, reconciled monthly.	Highest possible accuracy. Required to establish accurate calculations and functional equivalence. OVG (or DVG or CBFA) is a monthly limit, so parameter should be calculated monthly and corrected to STP.
	Energy content (higher heating value) of captured vent gas / $HHV_{VentGas}$	MJ/m^3	Measured	Measured based on site specific gas analysis. Gas analysis must be representative of the captured gas stream that was being vented in the baseline. Alternatively, if this is not available, use the default value for sales gas from	Annual	Direct measurement will be the most accurate. Defaults are as accepted in the Alberta Greenhouse Gas Quantification Methodologies.

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
				Chapter 15 the Alberta Greenhouse Gas Quantification Methodologies.		
	Energy content (higher heating value) of displaced fuel / HHV Fuel i	MJ/L, m^3 or other	Estimated	If available, measured based on site specific fuel analysis.	Annual	Direct measurement will be the most accurate. Defaults are as accepted in the Alberta Greenhouse Gas Quantification Methodologies.
	CO_2 Emissions Factor for Each Type of Fuel / EF Fuel i $_{CO2}$	g CO_2 per L, m^3 or other	Estimated	Where the displaced fuel is gas, then this should be site specific, calculated based on gas analysis using the procedures in Appendix C, Section C.1. of the Quantification Methodologies. Gas analysis must be representative of the captured gas stream that was being vented in the baseline. Alternatively, if this is not available, use the default value for sales gas from Chapter 15 the Alberta Greenhouse Gas Quantification Methodologies. Where the displaced fuel is non-variable (for example, diesel), as per the Carbon Offset Emission Factors Handbook.	Annual	Where the displaced fuel is gas, direct measurement will be the most accurate. Defaults are as accepted in the Alberta Greenhouse Gas Quantification Methodologies. Where the displaced fuel is non-variable (for example, diesel), use the relevant version of the Carbon Offset Emission Factors Handbook
	CH_4 Emissions Factor for Each Type of Fuel / EF Fuel i $_{CH4}$	g CH_4 per L, m^3 or other	Estimated	Where the displaced fuel is gas, then this should be site specific, calculated based on gas analysis. Gas analysis must be representative of the captured gas stream that was being vented in the baseline. Alternatively, if this is not available, use the default value from the Alberta Greenhouse Gas Quantification Methodologies. Where the displaced fuel is non-variable (for example, diesel), as per	Annual	Where the displaced fuel is gas, direct measurement will be the most accurate. Gas composition is typically reasonably stable and annual provides sufficient accuracy. Defaults are as accepted in the Alberta Greenhouse Gas Quantification Methodologies.

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
				the Carbon Offset Emission Factors Handbook		Where the displaced fuel is non-variable (for example, diesel), use the relevant version of the Carbon Offset Emission Factors Handbook
	N_2O Emissions Factor for Each Type of Fuel / EF Fuel i $_{N2O}$	g N_2O per L, m^3 or other	Estimated	As per the Carbon Offset Emission Factors Handbook	Annual	Use the relevant version of the Carbon Offset Emission Factors Handbook
	Global Warming Potential / $GWP_{CH4,\ N2O}$	Unitless	Estimated	As per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard.
B8 Upstream Fuel Extraction and Processing	Emissions $_{Fuel\ Extraction\ \&\ Processing}$ = [Σ (Vol. Fuel i * EF Fuel i $_{CO2}$) + Σ (Vol. Fuel i * EF Fuel i $_{CH4}$ * GWP_{CH4}) + Σ (Vol. Fuel i * EF Fuel i $_{N2O}$ * GWP_{N2O})] / 1000					
	Emissions $_{Fuel\ Extraction\ \&\ Processing}$	Tonnes CO_2e	N/A	N/A	N/A	Calculation of emissions associated with extraction and processing of fossil fuels used to run site equipment in the absence of the fuel and/or power provided by the project equipment
	Volume of Fuel Combusted for On-Site Thermal Energy and/or Electricity Production and/or Vent Gas Capture & Processing / $Vol._{Fuel}$	Volumes taken from B5 and/or B6				

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	CO_2 Emissions Factor for Each Type of Fuel / EF Fuel i $_{CO2}$	kg CO_2 per L, m^3 or other	Estimated	As per the Carbon Offset Emission Factors Handbook	Annual	Use the relevant version of the Carbon Offset Emission Factors Handbook
	CH_4 Emissions Factor for Each Type of Fuel / EF Fuel i $_{CH4}$	kg CH_4 per L, m^3 or other	Estimated	As per the Carbon Offset Emission Factors Handbook	Annual	Use the relevant version of the Carbon Offset Emission Factors Handbook
	N_2O Emissions Factor for Each Type of Fuel / EF Fuel i $_{N2O}$	kg N_2O per L, m^3 or other	Estimated	As per the Carbon Offset Emission Factors Handbook	Annual	Use the relevant version of the Carbon Offset Emission Factors Handbook
	Global Warming Potential / $GWP_{CH4,\ N2O}$	Unitless	Estimated	As per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard.
B10 Upstream Electricity Production	$Emissions_{Electricity} = E * EF_{Electricity}$					
	$Emissions_{Electricity}$	tonnes CO_2e	N/A	N/A	N/A	Calculation of emissions associated with production, transmission and distribution of electricity used to run site equipment in the absence of the fuel and/or power provided by the project equipment
	Electricity / E	MWh	Measured	Direct metering	Continuous metering	Standard practise. Frequency of metering is highest level possible.
	Emissions Factor for Electricity / $EF_{Electricity}$	t CO_2e per MWh	Estimated	As per the Carbon Offset Emission Factors Handbook	Once	Use the relevant version of the Carbon Offset Emission Factors Handbook. Emission Factor includes line losses.

5 Data Management

Documentation (documents and records) is a key element to emission offset project development, verification, and meeting all Alberta Emission Offset System requirements. The types of document and records required to demonstrate that an emission offset project meets regulatory and protocol requirements can vary by project. It is the project developer's responsibility to ensure they are meeting all protocol requirements and clearly document how they are going to meet protocol and system requirements in the emission offset project plan.

The verification process relies heavily on the quality and availability of documentation to support each emission offset project report. Projects are verified to a reasonable level of assurance, which means that objective evidence of project implementation is required to make an emission offset project claim. Reasonable assurance means the verifier is able to reach a positive finding on the accuracy and correctness of the GHG assertion. Attestation is not considered objective evidence and is not accepted.

In order to support the third party verification and any supplemental government reverifications, the emission offset project developer must put in place a system that meets the following criteria:

- All records must be kept in areas that are easily located;
- All records must be legible, and dated;
- All records must be maintained in an orderly manner;
- All documents must be retained in accordance to regulatory requirements;
- Electronic and paper documentation are both satisfactory; and
- Copies of records should be stored to prevent loss of data.

In the case of aggregated projects, the site owner/operator and the emission offset project developer must both maintain and retain records as required above for all emission reduction claims.

The project developer shall establish and apply quality management procedures to manage data and information. Written procedures must be established for each measurement task outlining responsibility, timing and record location. The greater the rigour of a management system for the data, the more easily verification can be conducted for the project.

5.1 Project Documentation

Documents are the instructions or plans of how a certain activity is carried out.

Documents are required to demonstrate that a project meets program criteria, eligibility, baseline eligibility and project offset quantification requirements. Examples of documents include offset project plan, procedures, specifications, drawings, regulations, standards, guidelines, etc. These documents must include a list of records available to the verifier that demonstrate the offset and protocol criteria have been met. The offset project documents should also indicate how the records will be managed (i.e., retention, storage and access).

Documents may be stand-alone or interdependent but must be complete. Documents may be subject to change or periodic update. The project developer must be able to demonstrate that the relevant version of a document is being used. Older versions applicable to specific GHG assertions must be retained as part of the project documentation as per section 31(6) of the Technology Innovation and Emissions Reduction Regulation.

In addition to the criteria outlined in this protocol, the emission offset project developer is required to provide documents to show that general offset criteria in the Standard for Greenhouse Gas Emission Offset Project Developers have been met.

Required documentation for project eligibility includes, but is not limited to:

- The name, contact information of the project developer(s);
- Evidence of project (or each subproject) activity start date;
- A list of subprojects and specific details for aggregated projects as required by the Director;
- Evidence and explanation of ownership for each project (or each subproject);
- Evidence that the project has been implemented (for example, permits for project condition, photographs of the pre- and post- project cases, updated PFDs, work orders, invoices, etc);
- Evidence that each project or subproject result in emission reductions in the province of Alberta including legal land location and GPS coordinates of the site;
- Project quantification methodology and calculations; and
- Evidence that the sources and sinks whether SS's are subject to a carbon price or not, and whether the project (or subprojects) are Category 1 or Category 2.

Required documentation for baseline condition includes, but is not limited to:

- Justification for changes to which sources and sinks are included (including any justifiable exclusion to Included SSs);
- The total GHG emissions for sources and sinks included in the baseline;
- Evidence (e.g. picture, P&ID) that a flare existed in the baseline condition if the project condition is tying in to a flare;
- Calculations applied to measured baseline data and justification for any alteration to those calculations; and
- The measured baseline data as recorded from the measurement device before calculations are applied.

Documentation for the project condition includes, but is not limited to:

- Justification for changes to which sources and sinks are included (including any justifiable exclusion to Included SSs);
- For each reporting period,
  - the total emissions accounted under each source and sink;
  - calculations applied to measured project data and justifications for any deviations from those calculations; and
  - the measured project data as recorded from the measurement device before calculations are applied; and
  - for destruction projects, evidence that the volume of captured methane was destroyed, and if some captured methane was vented, evidence that the vented emissions were reported

5.2 Monitoring and Measurement Requirements

- Meter readings must be temperature and pressure compensated such that the meter output is set to standard reference temperatures and pressures;
- Flow meters must be placed based on manufacturer recommendations:
  - Flow meters should be located downstream of all capture and compression equipment to account for any fugitive losses or venting, but upstream of any commingling with non-project gas streams. If a project simultaneously captures eligible and non-eligible vent gas sources the project must arrange its metering so that the eligible vent gas flow can be accurately metered
  - For destruction projects, project developers must correlate operational hours of destruction device with data from flow meter. If the data indicates that the destruction equipment is not operational but the meter is registering flow, it is assumed that the gas is vented and not being destroyed.
- Where the captured vent gas is directed to more than one end use than each stream must be metered separately. For example, if some captured vent gas generates electricity on-site and some is directed to the sales gas pipeline then each stream must be metered separately.
- Flow meters should be maintained and calibrated or validated according to manufacturer specifications and in accordance with the **more stringent of** a) AER requirements b) the requirement in the Alberta Greenhouse Gas Quantification Methodologies and c) the Specified Gas Reporting Regulation (which requires a calibration frequency of at least once every 3 years). For meters that cannot be calibrated or validated in the field, documentation must be provided by the emission offset project developer or the meter manufacturer to substantiate the use of an alternative meter maintenance program;
- Where a site or subproject does not have a representative gas analysis available for captured vent gas, it may use the default gas composition for rich gas from Chapter 15 of the Alberta Greenhouse Gas Quantification Methodologies. To be clear, this does not allow a project developer to choose to use the default gas analysis instead of gas analysis when it is available.

5.3 Records

Alberta Environment and Parks requires that emission offset project developers retain records as per the requirements in section 31(6) of the Technology Innovation and Emissions Reduction Regulation. Where the emission offset project developer is different from the person or entity implementing the activity, both must maintain sufficient records to support the offset project and any emission reduction claims. If the emission offset project developer or site ownership changes, sufficient records to support the emission offset project must be provided to the new owner to support any previous claims. Records may be requested anytime per Regulation, and must be provided.

Record keeping requirements include, but are not limited to:

- Evidence demonstrating if an emission source/sink is subject to a carbon price, if applicable;
- A record of all adjustments made to raw baseline data with justification;
- All data and analysis used to support estimates and factors used for quantification;
- Metering equipment specifications (model number, serial number, manufacturer's calibration or validation procedures/field meter proving method);

- Manufacturer's specifications test records for destruction efficiency (if using manufacturer's specifications);
- A record of changes in static factors along with all calculations for non-routine adjustments;
- All calculations of greenhouse gas emissions/reductions including methodology and emission factors;
- Measurement equipment maintenance activity logs;
- Measurement equipment calibration or validation records or field meter proving records;
- All AER approvals and requirements; and
- All verification records and results.

Specific records requirements for this protocol are set out in Table 6.

Table 6: Records Requirements

Eligibility/Project/Baseline	Record Requirement	Why it is required
Right to Transact	Record of ownership for each project and subproject for each reporting period; If the site has more than one owner, signed written agreement between the owners that is applicable to the reporting period; and Contract or some similar agreement between the emission offset project developer and the site owner(s) for the ability to serialize emission offsets.	To confirm the right to transact emission offsets.
Site Boundary	Dated map or aerial photo showing site boundary and any residences within 500 m; and GPS coordinates of specific equipment (if relevant); or Surface legal land location; and Downhole legal land location (if relevant).	To support the justification of including or excluding any sources/sinks if different from protocol. To ensure there is no double counting of emission reductions. To enable duplication review. To support that the emission reductions are occurring in Alberta. To demonstrate that the site is not within 500 m of a residence. To demonstrate that the site is not within the Peace River area as defined in Directive 084.
Site Commissioning Date	Petrinex data to demonstrate date site had first receipt or production.	To determine if the DVG applies. DVG applies for sites that receive or produce for the first time on or after January 1, 2022. Needed to use Flexibility Mechanism 1.
Gas to Oil Ratio	Petrinex data to demonstrate the gas to oil ratio is below 3000 m^3/m^3 for each reporting period.	To confirm site meets eligibility requirements under protocol.
FVI	Petrinex data to demonstrate the baseline FVI for each site; and	To confirm site meets eligibility requirements under protocol.

	Results of economic test (if relevant)	
Activity Start Date	Work order completion; or Complete (“as-built”) process and instrumentation diagram (P&ID); and Date/time-stamped photos of installation	To confirm the date the project or subproject is eligible to begin generating emission offsets. To confirm that the activity began after January 1, 2020. To confirm that the date subprojects are added to a project is accurate.
Aggregate Status	If the site is an aggregate site: AEP approval/acceptance indicating the site is an aggregate facility under TIER.	To determine which sources and sinks are appropriate to include/exclude. To determine project eligibility. If the site is an aggregate it is eligible. If the site is not aggregate and not opted into TIER it is eligible. Individual sites that are opted in to TIER or a regulated facility are not eligible.
Active Status	Petrinex records demonstrating that the site was ‘active’ for the two years prior to project initiation; and Petrinex records demonstrating that the site is ‘active’ for the reporting period. For sites that were developed less than two years before the initiation of the emission offset project this record is not required, but a Petrinex record demonstrating that the site was ‘active’ in the baseline scenario of each year before the initiation of the emission offset project.	To demonstrate project or subproject eligibility and ongoing eligibility and to demonstrate functional equivalence. To demonstrate that the site is regulated by Directive 060.
Operational Status	Petrinex records demonstrating that the site was producing for at least 50% of the 365 days prior to the activity start date.	To demonstrate that the site is not avoiding suspended status.
Baseline Condition	Raw data from project meters to show gas that is conserved, flared or combusted.	To calculate projected baseline.
Baseline Condition	Date/time-stamped photos of equipment pre-installation, showing gas was venting; or Original P&ID showing the gas was vented (and not flared) in the baseline condition; or Petrinex records demonstrating that venting was the baseline condition. Original P&ID showing that a flare existed in the baseline condition if the project condition is tie in to an existing flare; or	To establish project eligibility.

	Petrinex records demonstrating that a flare existed at the site in the baseline condition.	
Project Condition	Petrinex records indicating that the site is venting less than the OVG in the project condition.	To demonstrate legal additionality of the subproject.
Project Condition	Date/time-stamped photo of project that is conserving or destroying the vented gas; or As built P&ID showing equipment/piping changes.	To demonstrate that the equipment was installed.
Project Condition	Serial number on device (for implemented project equipment//technology); or Unique ID tag on pipe/pipeline for gas that is sent to sales.	To demonstrate that the equipment is unique and no double counting of emission reductions.
Flexibility Mechanism 2	Petrinex records that the fleet complies with the CBFA in the baseline / pre-project condition.	To demonstrate that the fleet complies with the CBFA prior to the project.
Flexibility Mechanism 2	Petrinex records that the fleet complies with the CBFA in the project condition during the offset reporting period.	To demonstrate that the fleet complies with the CBFA during the project.
Default Gas Composition	Search results from central gas records storage.	To demonstrate that there are no available, appropriate gas analysis.
Flexibility Mechanism 3	Annual methane emission report (as required by D060)	To demonstrate that any included compressors met the requirements of D060 in relation to compressor seal vent gas limits in the baseline condition.

5.4 Quality Assurance/Quality Control (QA/QC) Considerations

QA/QC procedures are applied to ensure that all measurements and calculations have been made correctly. Emission offset project developers remain responsible for clearly providing evidence and information that support their emission offset project meet all rules and requirements of the system, regulation, protocols. Some standard QA/QC procedures include, but are not limited to:

- Protecting monitoring equipment (sealed meters and data loggers);
- Protecting records of monitored data (hard copy and backup electronic storage);
- Checking data integrity on a regular and periodic basis (manual assessment, comparing redundant metered data, and detection of outstanding data/records);
- Comparing current estimates with previous estimates as a reality check;
- Providing sufficient training to operators to perform maintenance and calibration or validation of monitoring devices or contract with qualified third parties;
- Establishing minimum experience and requirements for operators in charge of project and monitoring;
- Ensuring that the measurement and calculation system and greenhouse gas reduction reporting remains in place and accurate;
- Checking the validity of all data before it is processed, including emission factors, static factors and acquired data;
- Performing recalculations of quantification procedures to reduce the possibility of mathematical errors;
- Storing the data in its raw form so it can be retrieved for verification;
- Recording and explaining any adjustment made to raw data in the associated report and files; and

Developing a contingency plan for potential data loss.

6 References

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