Enhanced Oil Recovery Quantification Protocol

Technology Innovation and Emissions Reduction Regulation
Version 2.1

1

Enhanced Oil Recovery Quantification Protocol Version 2.1 | Environment and Protected Areas

Contents

List of Tables

List of Figures

Summary of Revisions

Version	Date	Summary of Revisions
2.1	October 2025	Updated description of reversal to align with Quantification Protocol for Carbon Dioxide Capture and Permanent Geologic Sequestration Added definition of targeted geologic storage zone(s) Updated descriptions of emissions from subsurface to atmosphere, in both the baseline and project conditions Terminology related to ‘scheme’ under AER Directive 065 has been clarified to consistently refer to the ‘CO_2 EOR Storage Scheme,’ emphasizing its role in permanent geological sequestration and aligning with the definitions used in the CCS protocol. This update improves consistency in referencing the approved injection area and strengthens the delineation of project boundaries. Section 1.6 Reversals was revised to include: • Expanded definition of reversal to include AER determination, irreparability, and expert investigation criteria. • Added classification of reversals into Net Reversal and Post-Crediting Reversal. • Introduced last-in, first-out accounting for shared pore space reversals. • Added reference to error correction and true-up processes. • Included exemption clause for reversals caused by external events such as natural disasters or terrorism. Section 1.6.1.1 was added to: • Explain negative greenhouse gas statements when project emissions exceed baseline for reasons other than subsurface reversal. • Clarify reporting and correction process for negative statements. • List relevant emission sources Section 1.6.1.2 was added to: • Define net reversal due to subsurface CO_2 emissions. • Outline verification and reporting requirements for such reversals. Section 1.6.2 was added to: • Address reversals occurring after the crediting period. • Introduce requirement for annual containment assurance reports. • Define consequences such as holdback retirement or offset cancellation. Section 1.7 was added to: • Define and regulate removal credits from direct air capture or biogenic CO_2. • Specify analytical methods and frequency. • Outline verification and labelling requirements for removal credits. The calculation method for B1 Injected CO_2 in Table 6 now allows emissions to be calculated using either mass flow measurement or volumetric flow measurement, whereas previously only volumetric flow measurement was permitted. The calculation methods in Table 6 for **P10 Off-Site Electricity Generation** and **P11 Off-Site Heat Generation** have been updated to reflect how to quantify emissions from electricity and heat imported from outside the project boundary.
2.0	January 2022	The **Protocol Scope** was modified to reflect the carbon dioxide emissions and handling and to exclude the oil production and oil handling emissions and to cover various stages and activities of projects The **Protocol Eligibility** section requires the emission offset project developer must obtain Director approval prior to project initiation on the Alberta Emissions Offset Registry The crediting period was extended to align with carbon capture and storage protocol Protocol applicability conditions and **Protocol Flexibility** mechanisms were modified to align with the modified scope

		The **Baseline Condition** was updated to include relevant sources, sinks and reservoirs (SSRs) for the modified scope The **Project Condition** was updated to include relevant SSRs for the modified scope The **Quantification Methodology** was revised to account for the modified scope and to align as closely as possible to the carbon capture and storage offset protocol The **Documents and Records** requirements were clarifiedand updated Levied and non-levied emissions section was added Transfers of CO_2 and the associated holdback are allowed for Type 2 EOR schemes, when the remaining holdback is greater than 2% of the total cumulative holdback from project (other movement of CO_2 outside the project boundary is a project emission) Clarified: Holdback return process and CO_2 Transfers Added requirement for annual Containment Assurance Report submission to the Director to support the project Further defined offset project to include one EOR scheme Approval Area Provided quanitification for Type 1 and Type 2 CO_2 transfers and for reversals
1.0	October 2007	Version first approved for use.

Related Publications

- *Emissions Management and Climate Resilience Act (the Act)*
- Technology Innovation and Emissions Reduction Regulation (the Regulation)
- Specified Gas Reporting Regulation
- Standard for Greenhouse Gas Emission Offset Project Developers (the Standard)
- Standard for Validation, Verification and Audit
- Technical Guidance for Offset Protocol Development and Revision
- Carbon Offset Emission Factors Handbook
- Quantification Protocol for CO_2 Capture and Permanent Storage in Deep Saline Aquifers

1. Offset Project Description

Capturing carbon dioxide (CO_2) that would otherwise be emitted to the atmosphere and utilizing it in CO_2 Enhanced Oil Recovery (EOR) storage schemes can result in permanent net geological sequestration of CO_2. EOR schemes are typically operated with externally sourced CO_2 from industrial processes or power generation that are unrelated to the operation of the EOR scheme.

This quantification protocol establishes the methodology for quantifying the eligible greenhouse gas (GHG) emission reductions through net geological sequestration of CO_2 for EOR project activities. For this protocol only new (recently generated and captured), anthropogenic, CO_2 is eligible for emission offsets, CO_2 that was previously injected into a reservoir and recycled is ineligible for emission offsets.

This protocol was developed using a life cycle analysis and included an evaluation of emissions from the following elements of a typical EOR activity scheme which includes:

- CO_2 capture infrastructure. Includes a process or process modification within a facility to capture CO_2 emissions. The carbon capture facility may be integrated or separate from the emission source facility, and may use any commercial CO_2 capture technology;
- CO_2 transportation system. The transportation system may be a pipeline including compression and/or pumps to transport CO_2 from the capture facility to the EOR injection well(s) and/or may be CO_2 moved by vehicle from the capture facility to the EOR injection well(s); and
- Net geological sequestration of CO_2 through injection into an oil reservoir under a CO_2 EOR Storage Scheme, under the requirements and approval process outlined in AER Directive 065.Produced CO_2, emerging from the subsurface due to oil production is typically processed and reinjected (i.e. recycled) into the storage complex at CO_2 injection wells. Reinjected CO_2 quantities are not eligible for emission offsets in this quantification protocol to ensure no double counting of volumes. Applicable sources and sinks (SSs) are included in the project condition to account for situations where produced CO_2 is vented to atmosphere or transferred off site, (i.e. produced CO_2 that is vented to atmosphere is accounted for and quantified as a project emission).

Emission offset project developers using this protocol have familiarity with CO_2 capture and net geological sequestration projects in order to apply greenhouse gas quantification methodologies.

1.1. Protocol Scope

This protocol is applicable to emission reductions from the geological sequestration of CO_2 through enhanced oil recovery (EOR) activity in Alberta. This protocol is applicable only for emission reductions and sequestration that are not subject to a carbon price by any other policy mechanism and that are not required by law. Project activities which are in scope may include the capture of new CO_2, the compression, transport, injection, (inclusive of any re-injection) and the permanent net geological sequestration of CO_2. A process flow diagram for a typical CO_2-EOR project is shown in Figure 1.

This protocol does not apply to carbon capture and storage (CCS) activities for Carbon Dioxide Capture and Permanent Geological Sequestration (ie., dedicated storage), or to acid gas injection schemes associated with sour natural gas processing operations. Emission offset project developers with CCS projects should refer to the applicable Alberta approved quantification protocol.

Protocol Approach

This protocol applies to CO_2-EOR emission offset projects where the imported CO_2 is from a large emitter or opted-in facility regulated under the Techonology Innovation and Emissions Reduction

(TIER) Regulation, and would otherwise have been emitted to atmosphere and, under the project condition, is injected into an approved CO_2 EOR storage scheme. This protocol provides the methodology for emission offset project developers to follow and outlines the requirements for measurement, monitoring, quantification, reporting and verification. The regulated facility reports the exported CO_2 as part of their Total Regulated Emissions (TRE).

Baseline Condition

A projection-based baseline is used to quantify the CO_2 emissions that would have otherwise been emitted to the atmosphere in the absence of the emission offset project implementation. The baseline emissions are measured by metering the mass of new CO_2 injected into the CO_2 EOR storage scheme and do not include the mass of any re-injected CO_2 (i.e. recycled CO_2), or from another EOR scheme that has generated emission offsets. Baseline emissions include new injected CO_2 quantities only, not captured quantities. The scope of the greenhouse gases eligible under the baseline condition of this protocol is CO_2 only. The sequestration of methane (CH_4) or nitrous oxide (N_2O) is not eligible for emission offsets.

Project Condition

Project emissions which may be applicable to this activity include the CO_2 capture, compression, transport, injection, and re-injection activities associated with injecting CO_2 into an oil-producing geological formation. In addition, any potential CO_2 leakage or reversal from the storage formation must be accounted for, as per the monitoring and quantification requirements outlined in this protocol.

EOR projects primarily sequester CO_2. However, the CO_2 stream may contain several impurities such as CH_4, N_2O, H_2S, nitrogen, etc. A wide range of light hydrocarbons and/or sulfur-based gases may be emitted as a result of CO_2 capture, compression, transport, injection, re-injection and venting.

The scope of greenhouse gases that must be included in the project condition includes all related emissions of CO_2, CH_4, and N_2O, as per the quantification section of this protocol.

Emission Offset Project Developer

The CO_2 capture, compression, transport and net geological sequestration may or may not be conducted by the emission offset project developer. It is likely that several entities may be involved in the project activities. Each entity must maintain the records that need to be available for verification/reverification of the emission offset project and must allow access to the records to any third party assurance provider.

The emission offset project developer as described in the Regulation is accountable for the project meeting the requirements of both the Regulation and the Standard for Greenhouse Gas Emission Offset Project Developers (the Standard). It's the emission offset project developer's responsibility to work with all entities to obtain access to all records, data and equipment that may be required for monitoring, measurement, quantification and verification and must retain all project records according to the requirements in the Regulation, the Standard and this protocol.

CO_2 Capture Entity

The CO_2 capture entity is the originator of records, data and equipment related to CO_2 capture that may be required for GHG emissions quantification, reporting and verification. This may include evidence of captured CO_2 quantities, including concentration or composition and records for any heat, power or fuel used on-site for CO_2 capture.

Transport Entity

The transport entity is the originator of records, data and equipment related to CO_2 compression and transportation that may be required for GHG emissions quantification, reporting and verification. This may include evidence of delivered CO_2 quantities, including concentration or composition and records for any heat, power or fuel used on-site or fuel used to transport CO_2 by vehicles.

Injection/Sequestration Entity

The injection/sequestration entity is the originator of records, data and equipment related to CO_2 injection, reinjected CO_2 (i.e. recycled CO_2), as well as monitoring data and any GHG emissions (downstream of the injection meter) that may be required for quantification, reporting and verification. This will include evidence of injected gas CO_2 concentration, injected CO_2 quantities, evidence of closed loop re-injection system and records for any heat, power or fuel used on-site. Evidence of pressure monitoring as may already be required under project scheme regulatory approvals may also be provided.

1.2. Offset Crediting Period

The offset crediting period for this quantification protocol activity is 20 years, with possible extension period eligibility as set out in the Standard for Greenhouse Gas Emission Offset Project Developers.

1.3. Protocol Applicability

Emission offset project developers must be able to demonstrate that the emission offset project meets the requirements of the Alberta emission offset system, the relevant greenhouse gas regulations, this quantification protocol, the Carbon Offset Emission Factors Handbook, and other related Standards and guidance documents.

***The emission offset project developer must obtain a Director approval letter <u>prior to</u> project creation on the Alberta Emissions Offset Registry*.** The Director approval is needed to ensure the project boundary, CO_2 source and eligibility requirements are met. The information required for the emission offset project developer's submission will explain and provide evidence to demonstrate the project meets the following requirements:

1. A Director approval letter for the creation of an emission offset project on the Alberta registry using this quantification protocol. The emission offset projet developer will submit a written request to the Director and must include; an explanation of the emission offset project activity, a description of the overall scope, how the project meets all applicability criteria outlined here as 2-6, any flexibility mechanism to be utilized, any plan for alternate sequestration or transfers of the CO_2 outside of the project boundary, a completed Reservoir Pressures Table (see Required Project Documentation Section), the CO_2 EOR Storage Scheme approval for the activity, provided in accordance with the requirements outlined in AER Directive 065, along with an explanation of any special conditions that may apply to the activity (i.e. see item 7 below).

2. The emission offset project developer provides evidence to demonstrate that the CO_2 is captured from a large emitter or opted-in facility under the Regulation. This is demonstrated by actual EOR project schematics and by compliance with the measurement requirements set forth in the quantification section of this protocol.

3. The CO_2-EOR storage scheme must have obtained approval from the Alberta Energy Regulator (AER) under Directive 065 – Resources Applications for Conventional Oil and Gas Reservoirs and Section 39 of the Oil and Gas Conservation Act, and meets the requirements outlined under Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging and Testing Requirements.

4. The emission offset project boundary must be clearly described, which includes the emissions system; the CO_2 sources and if they are inside or outside the project boundary, the transportation system, the EOR geologic pool called the scheme Approval Area and the surface locations. A clear delineation of where the large emitter or opt-in facility stops and the emission offset project starts is part of the description.

The physical boundary for injection will be equivalent to the boundary set out in the CO_2 EOR storage scheme approval. The EOR emission offset project boundary includes:

- One EOR scheme approval and the geologic pool, called the scheme Approval Area, (the part of project boundary corresponding to the injection/sequestration entity), and
- The capture and transportation elements of the project unless the associated emissions are accounted for by the regulated facility,

5. The project must have obtained all required operating permits and relevant regulations in Alberta prior to emission offset project creation on the registry.

6. The net geological sequestration from the project must be quantified using actual measurements and monitoring as indicated in this protocol.

7. The emission offset project developer must provide confirmation of whether or not the project has any special conditions. These will require further details to be provided to the Director in order to obtain emission offset project approval, and include (but are not limited to):

- Projects with an CO_2 EOR Storage Scheme Approval that stipulate the reservoir pressure be reduced to or below the initial reservoir pressure, when production ceases or becomes very low.
- Projects that employ alternate technologies for CO_2 capture, transport, injection, or re-injection or use technologies and processes other than those commercially available and outlined in this protocol.

1.4. Flexibility Mechanisms

The quantification protocol is written for a single capture, single storage scenario (shown in Appendix A). If the project developer is implementing an emission offset project that is a single capture multiple storage, multiple capture single storage, or multiple capture multiple storage, they must measure CO_2 concentration or gas composition, and gas quantity according to the relevant scenarios shown in Appendix A. If the project developer would like to use a mass balance equation to calculate CO_2 concentration and/or prorate project emissions amongst project developers or EOR storage schemes they must apply one or both of the flexibility mechanisms (below) and fully justify the rationale for the flexibility mechanisms used. A clear explanation of the flexibility mechanism and alignment with the protocol quantification must be demonstrated and be verifiable.

Flexibility Mechanism 1:

This flexibility mechanism allows project developers to calculate (rather than measure) CO_2 concentration based on the weighted average in a single variable mass balance equation. The requirements for calculating CO_2 concentration for the various potential scenarios is outlined in **Appendix A**.

Flexibility Mechanism 2:

This flexibility mechanism allows project developers to prorate their emissions based on the amount of eligible CO_2 they inject. In cases where:

- there are more than one EOR emissions offset project using the same capture and transport systems but different injection schemes, or
- there is more than one capture and compression facility using the same transport of CO_2 to the same injection schemes,

Then all associated projects must use the same proration approach and must clearly justify and explain the proration method and the metering scheme and in the project plan and the project report.

Flexibility Mechanism 3:

This flexibility mechanism allows project developers to source CO_2 from direct air capture facilities in Alberta, as an eligible source. Project developers must notify the Director of their intent to utilize a DAC source, provide the details of the project boundary and the expected quantity of CO_2 per year. Project developers using this source of CO_2 must additionally quantify all vented, flared and fugitive emissions upstream of the injection meters except for emissions of the captured CO_2.

The quantification must meet the same rigor as for facilities as outlined in the Alberta Quantification Methodology(ies).

1.5. Risk Assurance – Discount Factors: Permanence and Holdback

CO_2-EOR project activities typically involve the injection of CO_2 into depleted oil pools until there is sufficient pressure for the CO_2 to become miscible with the oil in a single phase mixture, which helps move oil toward producing wells. It is expected that eventually CO_2 will be produced with the oil, and reinjected into the same EOR storage scheme for permanent storage.

1.5.1. Discount Factor (Df)

The risk for unintentional release of CO_2 is estimated to be low, and in Alberta, many risk mitigating regulatory processes are in place related to site selection, well drilling and completions, production, operations and abandonment requirements established by the AER. However, some risk remains which may result in the unintentional release of sequestered CO_2 either during the emission offset project or in the future. A discount factor of 0.005 is applied as a conservative approach to manage uncertainty associated with unintentional releases of CO_2. This discount is applied to the projection-based baseline and considered 'retired to the atmosphere'.

1.5.2. Holdback Factor (Hf)

The risk of intentional releases of CO_2 is mitigated by applying a holdback factor. The project developer must transparently calculate the holdback and include the quantification in each offset project report. The holdback factor is a percentage based on the type of CO_2-EOR storage scheme approval. The holdback factor for Type 1 EOR schemes is different than the holdback factor for Type 2 EOR schemes (see Section 4.2). Holdback factors are described in section 4 and are applied to the projection-based baseline. The calculated holdback is not serialized at the time of reporting. Project developers can request a release of holdback amounts and if approved, the holdback amount can be serialized after the end of the EOR activity and receipt of the related reclamation certificate. In a case where permanence cannot be verified, all holdback accumulated for an emission offset project will expire and be considered 'retired to the atmosphere'.

1.5.3. Holdback Release Process

A request for release of holdback must be submitted to the Director, with the required documents and conditions that must be met at the time of request for holdback release.

The project developer must submit a verified post project report that includes:

- The quantified amount of CO_2 that was released to the atmosphere from the CO_2 EOR Storage Scheme since the end of offset crediting period,
- The quantified amount of new CO_2 that was recently captured and not previously injected and produced from an EOR reservoir, and that was injected into the scheme since the end of the crediting period or last emission offset project report, whichever was most recent, and
- Evidence to show that produced CO_2 was recycled, re-injected and not released to atmosphere or moved outside the EOR scheme boundary.

The evidence for CO_2 remaining and CO_2 releases which may consist of:

- historic annual progress report submitted to the AER as required,
- produced volumes reported,
- previous offset project reports which must document all releases, that may have happened during the crediting period, were accounted for, and
- a summary of the verified holdback amounts from each project report, by vintage year, during the crediting period and any extension, and of the quantified amount of CO_2 that was transferred out of the project boundary since the end of the offset crediting period and where it was transferred. The Report Balance Sheet for CO_2 is in **Appendix C**.

The project developer must also provide the Director with:

- evidence of ownership of the project,
- any Operational Containment Assurance report, or other containment evidence that was submitted to the AER, and
- evidence that the CO_2 EOR Storage Scheme approval has been formally rescinded in accordance with AER Directive 065, andevidence that all project wells associated with the project have been abandoned, and
- a reclamation certificate obtained from the AER.

If the EOR scheme becomes an opt-in or large emitter under the Regulation, a summary of annual compliance reports can support the above request for release of holdback.

The returned holdback will be serialized as “Net Geological Sequestration at release of holdback” emission offsets. The vintage year of these emission offsets will be set at the year the reclamation certificate was issued by the AER, regardless of the timing of the request for release. The credit expiration period will be based on the vintage year per the Regulation.

1.5.4. Holdback Return Calculation for Emissions Offset Project

The method used to determine the amount of holdback returned as emission offsets, where:

Net Geological Sequestration at release of holdback = NGS HB Release

Total Cumulative Holdback from project = HB Total

Releases of CO_2 from project post crediting period = Releases post credit

Transfers of CO_2 from project post crediting period = Transfers post credit

Injections of newly captured CO_2 to the EOR scheme during the post crediting period = INJ post credit

NGS HB Release = min (HB Total - Releases post credit - Transfers post credit + INJpost credit or HB Total)

If NGS HB Release is less than zero it will be treated as a project reversal (see Section 1.6 Reversals).

Note that NGS HB Release cannot exceed HB Total from the end of the offset crediting period.

1.5.5. Transfers of CO_2 from an EOR Emission Offset Project

In order to meet the permanence requirements, and generate emission offsets, the geologically sequestered CO_2 must stay in the geologic formation in which it was injected (i.e. within the targeted geologic storage zone(s)). Accurate accounting of sources and sinks and the holdback are the mechanisms to ensure permanence during the offset crediting period. Accurate accounting in the Containment Assurance Report and the holdback are the mechanisms used to ensure permanence after the end of the offset crediting period. The mechanisms vary depending on whether the EOR storage scheme is a Type 1 or Type 2 approval.

Transfers of previously injected CO_2 are not eligible for generating emission offsets. Transfers of previously injected CO_2 from a CO_2-EOR emission offset project must be transparently tracked and reported in all project reporting documents to clearly delineate the quantity, where the CO_2 was transferred to and be included in the annual containment assurance report and the report balance sheet for CO_2. The project developer must provide evidence that all CO_2 that has been removed or released, has been or is now accounted for.

Transfers from Type 1 EOR emission offset projects:

- As Type 1 EOR storage schemes are not required to lower the reservoir pressure at abandonment, any transfers of CO_2 out of the EOR project during either the crediting period or the post crediting period:
    - must be accounted for as a forfeit of the same quantity of holdback (ie., 1,000 tonnes Holdback forfeited for 1,000 tonness CO_2 transferred), or

If there is insufficient holdback accumulated to forfeit the same quantity as CO_2 transferred, with the remaining holdback in the CO2-EOR project greater than 2% of cumulative baseline emissions:

- the project proponent must account for the rest of the transferred CO_2 as a project emission (P22). If this results in net positive emissions during a crediting period it will be treated as a reversal.

Transfers from Type 2 EOR emission offset projects:

- As Type 2 EOR storage schemes are required to lower the reservoir pressure at end of operations or abandonment, there are two scenarios where some amount of CO_2 (and holdback) may be transferred from a Type 2 EOR emission offset project to another EOR emission offset project:

Scenario 1) A Type 2 EOR emission offset project that is still within its offset crediting period (including extension) may transfer a quantity of CO_2 to another EOR emission offset project and account for it by transferring the equivalent quantity of holdback to the new EOR project, on the condition that the original EOR emission offset project:

- has sufficient accumulated holdback,
- the remaining holdback in the transferring project is greater than 2% of cumulative baseline emissions, after the transfer,

Then the transferred CO_2 will not count as a project emission for the EOR emission offset project exporting the CO_2 and

- the transferred CO_2 is removed from the net injection quantity for the reporting period.

This transfer of holdback effectively moves that portion of the holdback from the source project to the receiving project and moves the holdback return further out in time.

Scenario 2) A Type 2 EOR emission offset project that is within its crediting period, but has insufficient holdback accumulated to transfer according to scenario 1, must transfer all the allowed holdback and then account for the rest of the transferred CO_2 as a project emission (P22). If this results in net positive emissions during a crediting period it will be treated as a reversal.

After the offset crediting period has ended for a Type 2 EOR emission offset project, the transfer of previously injected CO_2 from an EOR emission offset project to another EOR emission offset project must be counted as a transfer of holdback. If insufficient holdback remains (including 2% of cumulative baseline emissions, after the transfer), it will be considered a reversal and the related emission offsets will be cancelled at the time of the transfer.

The hierarchy used to account for transfers of CO_2 must first be taken from the holdback quantity (Type 1 holdback forfeited, Type 2 transfer holdback), then from the previously credited CO_2 and finally from the non-credited, but injected CO_2 quantities, if any.

1.6. Reversals

This protocol defines a reversal as either:

1. an accidental release of CO_2 from the targeted geologic storage zone(s) during or after the offset crediting period that meets all of the following criteria:
   A. The AER has determined that a loss of containment has occurred under the CO_2 EOR Storage Scheme approval associated with the emission offset project, in accordance with AER Directive 065.
   B. The loss of containment cannot be remedied; and
   C. An expert investigation determines the quantity of CO_2 that is subject of the loss of containment which will reasonably leak into the atmosphere within 100 years of the occurrence of the loss of containment,

   or
2. the venting or removal of CO_2 after the injection meter through an injection well or a production well, and which is not accounted for during an offset crediting period, or after a crediting period with an adjustment to the project holdback.

The timing of a reversal will determine how the reversal is accounted for as per sections 1.6.1, and 1.6.2. Distinct time frames for reversals are considered as follows:

- Net Reversal – A reversal that occurs during any offset reporting period and results in a negative greenhouse gas statement.
- Post-Crediting Reversal – A reversal that occurs after the end of the offset crediting period.

True-up processes will consider the last CO_2 injected, to be the first emissions released as part of a reversal. In cases where multiple emission offset projects are injecting into shared pore space:

- The impacted sequestration reservoir will be the approved targeted geologic zone(s) identified in the CO_2 EOR Storage Scheme approval issued in accordance with AER Directive 065, andthe last-in, first-out accounting will be applied, causing the reversal to be apportioned to the appropriate offset projects holdback and/or serialized credits invalidation, until it is fully accounted for.

Once the impacted emission offset projects and/or holdback/credits are identified and apportioned, the error correction process as outlined in the Standard for Greenhouse Gas Emission Offset Project Developers and the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports will be applied.

Emission offset project developers shall not require true-up action under section 1.6 of this protocol in the event of a loss of containment of CO_2 if the project developer provides empirical evidence satisfactory to the Director demonstrating that the loss of containment was the result of an event unrelated to the selection, operation, or maintenance of the targeted geological zone(s) and associated injection infrastructure other than trespass into the targeted geological zone(s). Examples include a natural disaster or terrorist attack.

1.6.1.1. Negative Greenhouse Gas Statement

A negative greenhouse gas statement occurs when project emissions are greater than baseline emissions during any reporting period, resulting in a negative greenhouse gas statement in an emission offset project report. Section 1.6 provides information when the cause of the negative greenhouse gas statement is due to a reversal from the subsurface to atmosphere (under P22). However, a negative statement may also occur for other reasons, such as where project emissions are greater than net reductions due to a low volume of injected CO_2 during a reporting period. Project emissions for fugitive and venting from the capture, transport and injection of CO_2 are quantified through the existing sources outlined in Section 3.0 of this protocol, such as:

- P19 – Fugitive Emissions during Transport
- P20 – Venting at Injection and Production Wells and in Recycle Streams
- P21 – Fugitives at Injection and Production Wells and in Recycle Streams

Once the offset project report with a negative statement is verified and submitted to the Registry, the project developer must notify the director of the negative statement and a total number of invalid emission offsets must be removed from any previous reporting period for the project by following the error correction process set out in the Standard for Greenhouse Gas Emission Offset Project Developers. If any emission offsets that are removed were used to meet a compliance obligation, a facility must follow the true-up process set out in the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports.

The project reporting periods must be contiguous and not be of greater length than outltined in the Standard, for the duration of the offset crediting period.

1.6.1.2. Net Reversal

A net reversal occurs when project emissions are greater than baseline emissions during any reporting period due to emissions associated with a reversal of CO2 from the permitted geologic storage zone(s) resulting in a negative greenhouse gas statement. Emissions from a reversal must be quantified under P22 – Emissions from subsurface to atmosphere, in any reporting period, or after the crediting period, according to the methods outlined in this quantification protocol. If there is a reversal event that occurs during the reporting period and emissions from P22 result in a negative greenhouse gas statement this is considered a net reversal and must be verified and reported by the project.

Once an offset project report with a negative statement is verified and submitted to the Registry, the project developer must notify the director of the negative statement and a total number of invalid emission offsets must be removed from any previous reporting period for the project by following the error correction process set out in the Standard for Greenhouse Gas Emission Offset Project Developers. If any emission offsets that are removed were used to meet a compliance obligation, the regulated facility must follow the true-up process set out in the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports.

1.6.2 Post-Crediting Reversal

If a reversal occurs after the end of the offset crediting period, it will be considered a post-crediting reversal. In the post crediting period, the emission offset project developer will not be submitting regular offset reports. To ensure the department continues to have assurance of containment, the emission offset project developer of a project must submit an annual containment assurance report to the Director. A containment assurance report template is provided in Appendix C and must be used to report post-crediting status by the project developer or the projects' Holdback will be retired to the atmosphere.

Reversals of carbon dioxide during the post-crediting period must be reported on the containment assurance report and, as applicable will result in the Director cancelling Holdback from the project or cancelling invalid emission offsets in the amount of the reversal within the project. If any emission offsets that are invalid were used to meet a compliance obligation, the regulated facility must follow the true-up process set out in the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports.

1.7. Removal Credits

A removal or sequestration activity involves a removal of CO_2 from the atmosphere that would have otherwise remained in the atmosphere. Under this protocol, the net CO_2 captured from a direct air capture facility (under flexibility mechanism 1) or the net CO_2 captured from a biogenic source that is permanently sequestered in a targeted geologic storage zone(s) capable of permanent storage, may be labelled as a 'Removal' credit on the Alberta Emissions Offset Registry.

The emission offset project developers state their intent to label removal credits by written request to the Director, under section 1.3 requirement 1 and document in the offset project plan and each offset project report. The offset project plan should outline how the project have met, or will meet, the following requirements:

1. The project must capture CO_2 from a direct air capture facility or capture biogenic CO_2 (i.e., biomass energy with CCS).
2. For biogenic CO_2, the project must determine the biogenic portion of the CO_2 emissions using ASTM D6866-16 "Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis". Facilities are free to conduct analyses at a greater frequency than listed below if they choose. Facilities that are using fuel base assessment or analysis may apply to the Director for a deviation to use that method for this purpose.
    a. Analysis must occur at least every three months if the biogenic CO_2 is within a mixed stream at the point of metering upstream of co-mingling.
    b. Analysis must occur at least once every two years if the biogenic CO_2 is not within a mixed stream at the point of metering upstream of co-mingling.
3. Allocate total emission offsets between removal and non-removal types using a weighted average of the composition analysis outlined in each verified offset project report.
4. A verifier must confirm assertions of claimed emissions reductions associated with the generation of removal credits and non-removal credits in their verification report that matches the offset project report. In the event of any discrepancies between the offset project report and verification report (or verification finding), no emission offsets will be able to be labelled as Removal credits for that reporting period.

CO_2 removal credit types on the Alberta Emissions Offset Registry will carry no additional compliance benefit and are subject to all requirements and restrictions of an emission offset under TIER. An emission offset projects' Holdback may not be labelled in the registry, at the point of release.

1.8. Glossary of Terms

Alberta Electricity Grid	A system of conductors through which electrical energy is transmitted and distributed throughout the province. This electricity grid is an interconnected network of high voltage transmission and lower voltage distribution for delivering electricity from suppliers (generators) to consumers across the province.
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.
Capture Site	The point in the process where gas containing CO_2 that would otherwise be emitted is separated and captured for eventual injection as part of a CO_2-EOR storage scheme.
Containment Assurance	Demonstration that the features and geologic structure of the CO_2-EOR activity are adequate to provide safe, long-term containment of CO_2, and that the CO_2 flood is operated in a way to assure containment of the CO_2 in the EOR storage complex. [Source: ISO 27916:2019]
Directive 007	*Volumetric and Infrastructure Requirements* (February 2016). This directive sets out the Alberta Energy Regulator'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 must be submitted.
Directive 017	*Measurement Requirements for Oil and Gas Operations* (March 2016). This directive clarifies, consolidates and updates the Alberta Energy Regulator's 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 must be reported to the Alberta Energy Regulator (see Directive 007).
Directive 020	*Well Abandonment* (March 2016). This directive details the minimum requirements for abandonments, casing removal, zonal abandonments and plug backs as required under Sections 3.013 of the Oil and Gas Conservation Regulations.
Directive 051	*Injection and Disposal Wells: Well Classifications, Completion, Logging, and Testing Requirements* (March 1994). This directive classifies injection and disposal wells according to the injected or disposed fluid and specifies design, operating, and monitoring requirements for each class of well.
Directive 065	*Resources Applications for Oil and Gas Reservoirs* (April 2016). This directive details the process to apply to the Alberta Energy Regulator for all necessary approvals to establish the strategy and plan to deplete a hydrocarbon pool or portion of a pool using one resource application.
Directives	Documents 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 Alberta Energy Regulator.
Discount factor (Df)	A set percentage of the projected baseline is deducted from the baseline emissions to account for the risk of the unintentional release of CO_2 from the emission offset project, during its operations and in the future. It is calculated separately for transparency and accounting purposes.
Enhanced Oil Recovery	Oil recovery over and above what is obtained using the natural pressure of the reservoir by injecting CO_2 and/or water alternating gas. For the purposes of this protocol, CO_2 – Enhanced Oil Recovery produces hydrocarbons from a reservoir using the injection of CO_2. [adapted from: ISO $_2$7916:$_2$019]
Enhanced Oil Recovery Storage Scheme (Storage Complex)	Storage reservoir, trap, and such additional surrounding geology in the subsurface as defined by the AER Directive 065 storage scheme approval within which injected CO_2 will remain in safe, long-term containment. Includes the subsurface geological system which comprises the geological stratum (or strata) into which CO_2 is injected for the purpose of storage and identified seal(s). See also, targeted geologic storage zone(s).

Higher Heating Value (HHV)	The amount of heat released during the combustion of a fuel and includes the heat in the water component product of combustion. Use of HHV assumes that heat above 150°C can be utilized.
Holdback Factor (Hf)	A set percentage of the projected baseline emissions is deducted and held back from the baseline emissions to account for possible intentional or operator caused reversals from the project during its lifetime. The net holdback will be released or considered sequestered after specific conditions (i.e., application with evidence of well abandonments, reclamation certificate and true up for any reversals) have been provided by the EOR emission offset project developer. The holdback percentage is based on the type of CO_2-EOR storage scheme approval.
Incremental, Directly Connected Electricity	Electricity sourced for the project, from a site that is not a large emitter or opted-in facility that meets the following three criteria: Direct Connection: the source of electricity is directly connected to the site or connected through a recognized Industrial System Designation (ISD) that is separate from the provincial electricity grid; and Dedicated Electricity Contract: the electricity is sourced using a dedicated electricity purchase agreement; and Incremental Generation under contract: the electricity used in the project represents incremental, and under contract, electricity generation that was not previously utilized. This may include either newly installed generation capacity or capacity that has not been utilized in the average year, over the three-year baseline period prior to and ending within 6 months of the initiation of the project. It is determined as: the quantity of generated electricity in the offset reporting period beyond average generation in the three baseline years or generation from new capacity installed.
Industrial System Designation	A designation granted by the Alberta Utilities Commission to describe a regional integrated electric system. The system includes: 1) one or more generating units, located on the property of the industrial operations it is intended to serve; 2) one or more industrial operations that are serviced by the generating unit(s); and 3) a high degree of integration of the electric system with the industrial operations. There is common ownership and management of the components of the system.
Injected Fluid	The total quantity of new CO_2 rich fluid that is measured directly upstream of the CO_2-EOR storage scheme or at each wellhead. Injected fluid does not include any quantity of reinjected CO_2 (i.e. recycled CO_2). Injected fluid is measured in the project condition upstream of the re-injection stream.
Injection Meter	Meter used for quantifying injected CO_2. This is expected to be a custody transfer meter as close as possible to the injection field and wells.
Regulated Facility	A facility subject to Alberta's' provincial greenhouse gas Regulation. The facility emissions are fully accounted for and verified.
Monitoring, Measurement and Verification (MMV)	Monitoring and measurement are surveillance activities for ensuring safe and reliable operation of a carbon storage project. Verification, in relation to the monitoring and measurement of CO_2 containment, refers to the comparison of measured and predicted performance. MMV is not required by this emission offset protocol. MMV may or may not be required by the AER storage scheme approval.
New CO_2	Anthropogenic CO_2 recently captured and not previously injected into a reservoir and recycled (including CO_2 from biomass use), or recently captured CO_2 from a direct air capture facility. Must not have previously been credited for sequestration.
Opt-In Facility	A facility that met the requirements and applied to be regulated under the provincial greenhouse gas Regulation.
Permanent Storage/Net Geological Sequestration	The isolation of CO_2 in subsurface formations. Injected CO_2 is trapped within pore spaces, dissolved in formation fluids and (over long time periods) mineralized.
Process Element	Components of the baseline or project that illustrate the flow of CO_2 but are not the sources or sinks included in the quantification of baseline and project emissions.

Project Reservoir	Geologic reservoir into which CO_2 is injected for production of hydrocarbons in paying or commercial quantities. [Source: ISO 27916:2019] Also called storage complex in this protocol.
GHG Reservoir	Component, other than the atmosphere, that has the capacity to accumulate greenhouse gases, and to store and release them. [Source: ISO 14064-2:2019]
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]
Regulated Facility	A facility subject to TIER, as a large emitter or opted-in facility. Emissions are accounted for and verified on an annual basis.
Steam Methane Reforming	The most common process by which hydrogen is produced. Heated methane and steam are brought into contact with a catalyst, which produces H_2, CO_2, CO, and other trace compounds. The CO stream is further reacted with steam in a shift reactor to produce H_2 and CO_2. The CO_2 and H_2 are then separated using pressure swing adsorption units, membranes or absorption columns to generate pure hydrogen.
Targeted Geologic Storage Zone(s)	The targeted geological formation(s) that contribute to providing secure long-term sequestration of CO_2 as outlined in the D065 CO_2 EOR storage scheme approval. It may include one or more seals and one or more zones that have the potential to accept sequestered CO_2.
Trap	Any feature or mechanism that alone or in combination provides a low-permeability confining geologic layer (cap rock or seal). This includes mechanisms for storage in the pore spaces of the EOR complex (physical, stratigraphic, or structural trapping), by capillary pressure from the water in the pore spaces between the rock (residual trapping), by dissolution in the in situ formation fluids (solubility), by hydrodynamic trapping, by adsorption onto organic matter or by reacting in geologic formations to produce minerals (geochemical trapping). [adapted from ISO 14064-2:2019]
Type 1 CO_2-EOR Scheme	Where the AER scheme approval does not require lowering the reservoir pressure at abandonment below the reservoir pressure at the end of production operations.
Type 2 CO_2-EOR Scheme	Where the AER scheme approval requires lowering reservoir pressure at abandonment below the pressure at the end of production operations.
Well Blowout	An unintended flow of wellbore fluids (oil, gas, water or other substance) at surface that cannot be controlled by existing wellhead and/or blowout prevention equipment; or a flow from one pool to another pool(s) that cannot be controlled by increasing the fluid density (underground blowout), as defined by the Alberta Energy Regulator Directive 059.
Well Kick	Any unexpected entry of water, gas, oil or other formation fluid into a wellbore that is under control and can be circulated out, as defined by the Alberta Energy Regulator Directive 059.

1

2. Baseline Condition

The baseline scenario for this activity is non CO_2-enhanced oil recovery and emitted CO_2 from a regulated facility.

The operation during the baseline is assumed to be enhanced oil recovery, without the use of CO_2. Thus, the oil produced from a CO_2-EOR project can be assumed to be unchanged. The oil production is not an additional activity and does not factor into the calculation of sequestered CO_2. The emissions associated with oil production are considered equivalent in the baseline and the project condition so are excluded.

The baseline for this protocol is dynamic projection-based. Therefore, during the project, the total quantity of CO_2 measured directly upstream of the injection wellheads is projected to the baseline condition. This does not include the quantity of any reinjected CO_2 (i.e. recycled CO_2) or previously credited CO_2.

This projected baseline ensures the baseline correctly accounts for the year to year variation in CO_2 that is captured and injected in the project, and is therefore dynamic. Any CO_2 produced with the oil must be re-injected or accounted for as an emission or transfer if it leaves the offset project boundary. The baseline condition is presented in detail in Figure 1, with the relevant GHG sources, sinks and reservoirs (SSRs) and the EOR process flow diagram. Descriptions of each of the SSRs is provided below.

2.1. Identification of Baseline Sources, Sinks, and Reservoirs (SSRs)

The identification of sources, sinks and reservoirs 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. SSRs 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 sources, sinks and reservoirs were identified by reviewing the relevant process flow diagrams, consulting with technical experts and reviewing best practice guidance. This iterative process confirmed that SSRs 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 SSRs were organized into life cycle categories and depicted in Figure 2. A description of each SSR and its classification as controlled, related or affected is provided in Table 1 and a description of each source sink is included in Table 2.

Figure 1: Baseline Process Flow Diagram

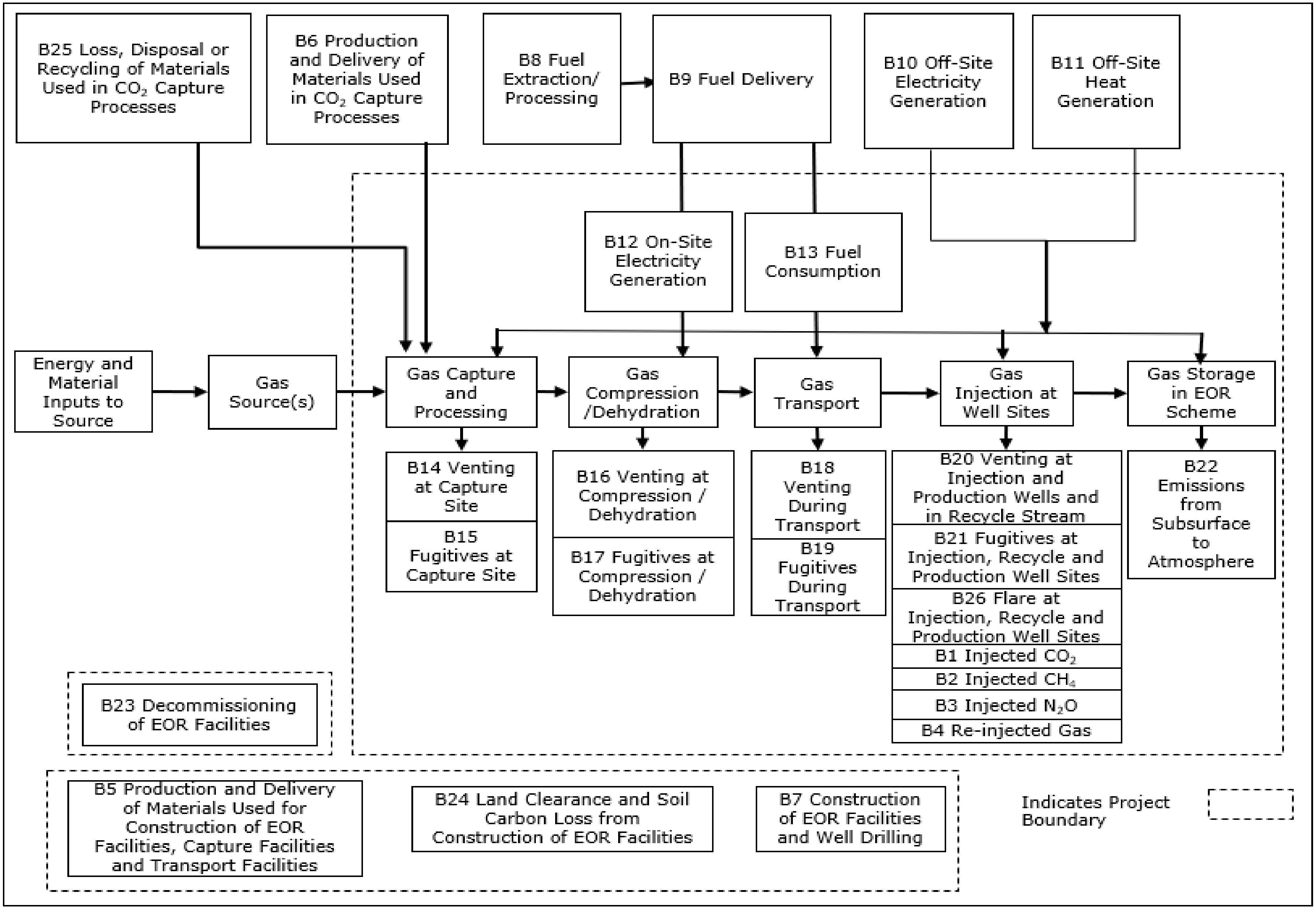


Table 1. Baseline Process Elements

Process Elements	Description
Energy and Material Inputs to Gas Source	Energy and material inputs to the gas source may include electricity, heat and fuel, which may be supplied from on-site or off-site sources.
CO_2 Source(s)	The CO_2 source includes any type of process that generates CO_2-rich fluid, such as steam methane reforming from a GHG regulated facility in Alberta.
Capture and Processing	The CO_2-rich stream coming from the CO_2 source may need further purifying and processing before it can be injected. The capture technology applied at the capture facility may use amine as a solvent to separate CO_2 from other components of the gas source.
Compression/Dehydration	The CO_2-rich stream is compressed before it can be transported to the CO_2-EOR site. Dehydration may also be required to prevent hydrate formation. This may be achieved through heating or other processes.
Fluid Transport	The CO_2-rich stream will be transported to the injection site via pipeline, or in some cases, by vehicle. Depending on the length of the pipeline or the location of capture facilities, additional booster compression may be needed.
Fluid Injection	The CO_2-rich stream will be injected at the EOR storage scheme, for example with the water-alternating-gas method. In certain cases, additional energy inputs may be required at the injection wells for the injection operation or to operate monitoring equipment.
Re-injected/Recycled Fluid	Any injected fluid that comes back to surface as solution gas is recovered and re-injected (recycled), and additional compression may be required.
Storage in EOR Scheme	The CO_2-rich stream will be injected into one or more project reservoirs that are suitable and approved by AER for permanent storage via EOR.

NOTE: Process elements are included for illustrative purposes only.

Figure 2: Baseline Condition SSRs

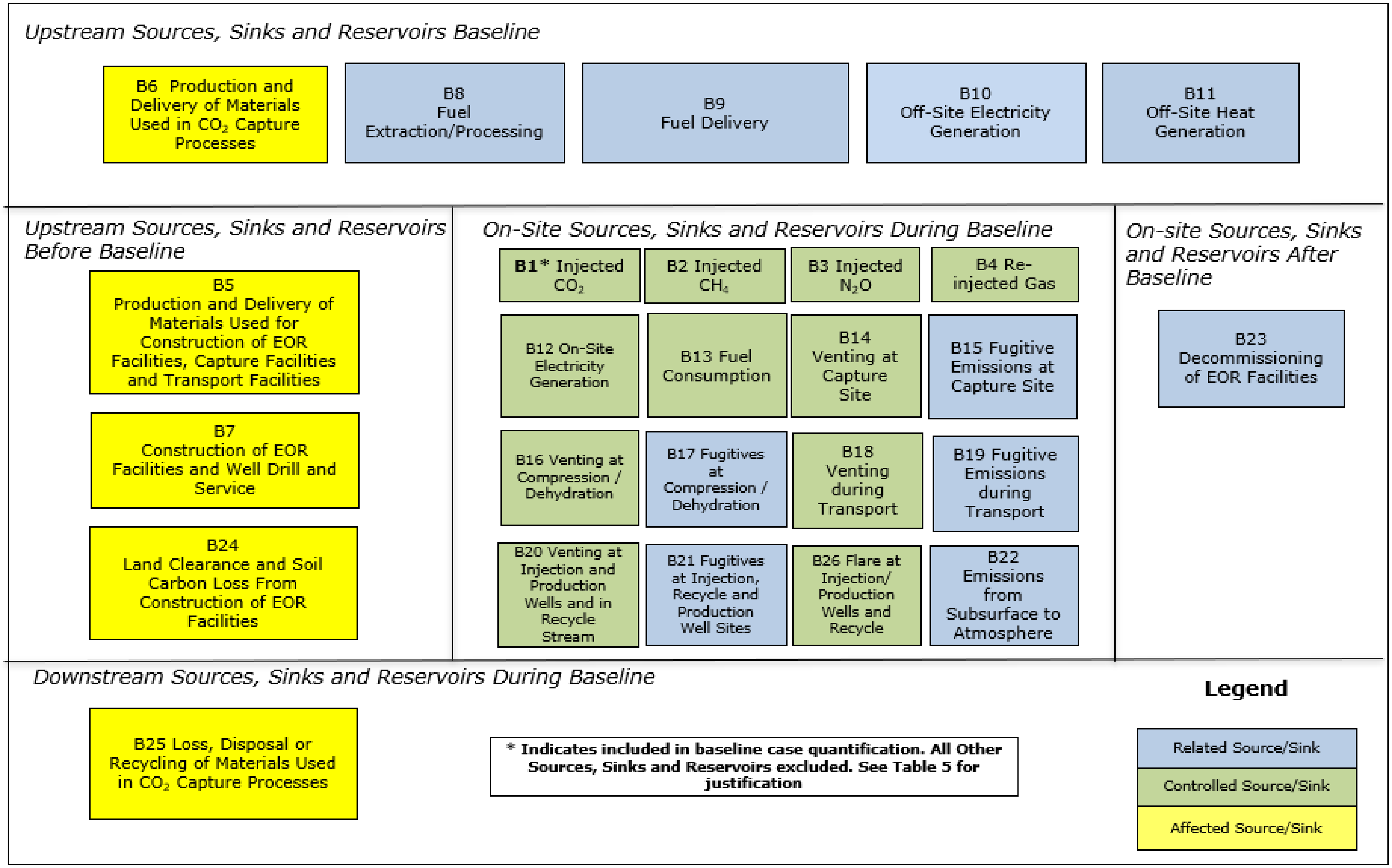


Table 2. Identification of Baseline Sources, Sinks and Reservoirs (SSRs)

Source, Sinks and Reservoirs (SSRs)	Description	Controlled, Related or Affected
Upstream SSRs During Baseline		
Production and Delivery of Materials used in CO_2 Capture Process	Material inputs for CO_2 capture and processing are required. These inputs may be specialized chemicals or additives such as amines. Greenhouse gas emissions are attributed to the fossil fuel consumption for transport of these materials, and the electricity and fossil fuel inputs for their production. The total aggregate quantity of each chemical delivered to the site must be tracked.	Affected
B8 Fuel Extraction/Processing	Each of the fuels used throughout the project will need to be sourced and processed. This will allow for the calculation of the greenhouse gas emissions from the various processes involved in the production, refinement and storage of the fuels. The total volumes of fuel, for each of the SSRs, are considered under this SSR. Volumes and types of fuels used throughout the project are the important characteristics to be tracked.	Related
B9 Fuel Delivery	Each of the fuels used throughout the activity will need to be transported to the site. This may include shipments by tanker or by pipeline, resulting in the emissions of greenhouse gases. It is reasonable to exclude fuel sourced by taking equipment to an existing commercial fueling station as the fuel used to take the equipment to the site is captured under other SSRs and there is no other delivery.	Related
B10 Off-site Electricity Generation	The total quantities of emissions associated with electricity imported and used by the capture facilities, the transport facility and the enhanced oil recovery injection and re-injection facilities must be tracked to estimate related greenhouse gas emissions.	Related
B11 Off-Site Heat Generation	Emissions associated with generation of thermal energy off site. Off-site heat delivered to the emission offset project may have been generated independently.	Related
Upstream SSRs Before Baseline		
B5 Production and Delivery of Materials Used for Construction of EOR Facilities, Capture Facilities and Transport Facilities	Materials used in the construction of carbon capture, transportation and EOR facilities such as steel and concrete will need to be manufactured and delivered to the site. Emissions are attributed to fossil fuel and electricity consumption for material manufacture and fossil fuel consumption for material delivery.	Affected
B7 Construction of EOR Facilities and Well Drilling	Site construction will require a variety of heavy equipment, smaller power tools, cranes, generators and well drilling operations. The operation of this equipment will have associated greenhouse gas emission from the use of fossil fuels and electricity and from the potential kick or blowout event that could release hydrocarbons during the drilling of injection, production and monitoring wells.	Affected
B24 Land Clearing and Soil Carbon Loss from Construction of Enhanced Oil Recovery Facilities	The clearing of vegetated or forested land for site preparation may release CO_2 from the soil into the atmosphere that was previously stored in soil.	Affected
On-Site SSRs During Baseline		

B1 Injected CO_2	All CO_2 emissions released to the atmosphere in baseline as waste CO_2. Baseline emissions are projected back, using the direct measurement of the quantity of fluid that is measured upstream of the injection wellheads in the project condition. Excludes reinjected fluid.	Controlled
B2 Injected CH_4	All CH_4 emissions released to the atmosphere in baseline, as projected back from the project condition. Baseline emissions are projected back, using direct measurement of the quantity of fluid that has been measured upstream of the injection wellheads in the project condition.	Controlled
B3 Injected N_2O	All N_2O emissions released to the atmosphere in baseline, as projected back from the project condition. Baseline emissions are projected back, using direct measurement of the quantity of fluid that has been measured upstream of the injection wellheads in the project condition.	Controlled
B4 Re-Injected Fluid	All CO_2 that is produced and re-injected at the EOR storage scheme must be accounted for and these quantities must be differentiated from B1 Injected CO_2. In some cases, this reinjected fluid is CO_2 that had been previously injected, but in other cases, the re-injected CO_2 was derived from carbonate materials in the project reservoir (i.e., formation CO_2).	Controlled
B12 On-Site Electricity Generation	Electricity inputs may be required for CO_2 capture, compression, transportation, injection and re-injection. Electricity may be generated independently or from cogeneration within the project boundary. The quantity and type of fuels consumed to generate electricity, and the quantity of electricity consumed by the project from each generating source must be tracked.	Controlled
B13 Fuel Consumption	Fuel may be consumed for CO_2 capture, compression, transportation, injection and re-injected. The quantity and type of fuels consumed by the project from each emitting source must be tracked.	Controlled
B14 Venting at Capture Site	Some gases may be vented from the CO_2 capture facilities during the project condition. CO_2 venting may also be necessary for equipment maintenance or emergency shutdowns. These gases will be composed primarily of CO_2 with trace amounts of other gases.	Controlled
B15 Fugitive Emissions at Capture Site	Unintended leaks of gas from the CO_2 capture, measurement and processing unit may occur through faulty seals, loose fittings, or equipment.	Related
B16 Venting during Compression/Dehydration	Planned and emergency venting may be necessary for compressor and dehydrator maintenance and/or emergency shutdowns.	Controlled
B17 Fugitive Emissions during Compression/Dehydration	Unintended leaks of gas from the compressor and/or dehydrator may occur through seals, loose fittings, equipment, or compressor packing.	Related
B18 Venting during Transport	Planned and emergency venting may be necessary for pipeline maintenance and/or shutdowns.	Controlled
B19 Fugitive Emissions during Transport	Unintended leaks of gas from the CO_2 pipeline, transportation equipment, and additional compressors may occur through seals, loose fittings, equipment, or compressor packing.	Related
B20 Venting at Injection/ Production Wells and Recycle	Planned and emergency venting may be necessary for injection, production or re-injection well work overs, mechanical integrity checks, and maintenance. Instances of venting must be logged, including the duration of the venting event and the estimated volumes vented.	Controlled
B21 Fugitive Emissions at Injection/Recycle and Production Well	Unintended leaks of gas at the CO_2 injection wells, re-injection wells or production wells may occur through valves, flanges, piping, pipe connections, mechanical seals, or related equipment.	Related

B26 Flare at Injection/Production Wells and Recycle	Planned and emergency flaring may be necessary for injection, production or re-injection well work overs, mechanical integrity checks, and maintenance. Instances of flaring must be logged, including the duration of the flaring event, sources of gases flared including any additional natural gas makeup and the estimated quantities flared.	Controlled
On-Site SSRs After Baseline		
B22 Emissions from Subsurface to Atmosphere	Accidental emissions to the atmosphere may occur from gas migration through undetected faults, fractures and/or subsurface equipment resulting from compromised casing/cement/wellhead or packer/tubing. These emissions must be quantified. Intentional releases or removals/transfers of CO_2 (when there is insufficient holdback) or net reversals are included here also	Related
B23 Decommissioning of CO_2 Capture and Enhanced Oil Recovery Facilities	Infrastructure is decommissioned at the end of project operations. This involves the disassembly of the equipment, demolition of on-site structures, landfill disposal of some materials, environmental restoration, re-grading, planting or seeding, and transportation of materials off-site. Greenhouse gas emissions result from fossil fuels combustion and electricity use.	Related
Downstream SSRs During Baseline		
B25 Loss, Disposal, or Recycling of Materials Used in CO_2 Capture Processes	Material inputs are either disposed or re-injection at the end of their useful life. Greenhouse gas emissions result from the transportation of materials to industrial landfill and/or material recycling processes. Emissions are also associated with the loss of material during project operation.	Affected

3. Project Condition

The CO_2-EOR activity is defined as including three distinct components: the capture and compression of CO_2; the transport of CO2 to the injection wells; and the metering and injection of CO_2 that results in the permanent geological sequestration of the CO_2 in an approved EOR storage scheme (i.e. storage complex). Produced CO_2, emerging from the subsurface due to oil production, is typically processed, and reinjected into an EOR storage scheme (storage complex). No reinjected fluid (i.e. recycled fluid) quantities are eligible for emission offsets under this quantification protocol. The production of oil is also a major component of an EOR storage scheme. Oil production and the emissions explicitly associated with the oil production are not included in the quantification of the EOR offset project emissions (i.e., emissions from fuel combusted in pumping oil to a flow line, etc.). Emissions from oil production are not incremental to the baseline condition for this activity, which is EOR occurring by a process other than CO_2 injection.

The main process elements of a typical CO_2-EOR activity are described below. CO_2-EOR emission offset projects may employ other capture, transport, injection, production and re-injection approaches and processes. Approval from the Director under the Act will be required for all new projects and for any deviations from this protocol. If the emission offset project scenario changes, for example to include new capture sites, the project developer must notify the Director of the new source of CO_2 and update the offset project plan to document the change in project scenario.

CO_2 Capture and Compression

For this protocol, only new CO_2 (i.e. anthropogenic CO_2 recently captured and not previously injected and produced from an EOR reservoir) reported as exported from a regulated facility that is ultimately captured and used is eligible. CO_2 capture refers to the process of capturing CO_2, and often includes the separation of CO_2 from other gas species generated at the emissions source. All CO_2 capture technologies are eligible under this protocol. The typical CO_2 capture infrastructure consists of the following main process blocks:

- CO_2 capture from existing high purity process streams, e.g., fertilizer plant, gasification; or,
- CO_2 separation. This typically includes amine solvents, absorbers and associated equipment; and/or, solvent regeneration unit(s), which may include the following:
  - Stripper column and associated reboiler, pumps and heat exchangers;
  - Solvent filtration;
  - Solvent storage;
  - CO_2 vent stack; and
- CO_2 compression, which may include a multi-stage compressor with an electrical motor and interstage coolers and knockout drums, CO_2 dehydration and interim CO_2 holding facilities.

GHG emissions associated with capture and compression processes are accounted for in the project condition.

Transport

The transportation system may be a pipeline including booster compression and/or pumps to transport CO_2 from the capture facility to the injection well(s). Alternatively, transportation could be CO_2 moved by vehicle from the capture facility to the injection wells.

Pipeline transportation system infrastructure may include equipment such as electrical or mechanical compressors or pumps, and a pipeline network connecting the capture site to the injection site with line block valves and metering equipment. Supervisory Control And Data Acquisition (SCADA) systems or other systems maybe used to collect, transmit data from the pipeline to a control centre and to monitor line block valves. CO_2 is typically transferred in a dense phase and emissions arising from the inline compression and pumping of CO_2 at the capture site are part of the transport system.

Storage

The CO_2 storage infrastructure may include; injection wells, measurement and gas analysis equipment, and flow lines from the main transportation system to the individual injector wells.

Metering of new injected fluid quantities and CO_2 concentration to calculate injected CO_2 quantity takes place as close to the injection point as is reasonable. This must be demonstrated by project schematics. A mass balance approach may be appropriate if project schematics confirms measured parameters for all inputs except for the one variable being solved for.

Once injected into the CO_2 EOR Storage Scheme (subsurface storage complex), as defined in the approval issued in accordance with AER Directive 065, CO_2 is contained within the pore spaces of the reservoir.Geologic storage, with the exception of adsorption, is most efficient at depths where the formation pressure and temperature are sufficient to cause CO_2 to remain in a dense state.

CO2 is stored by one or more of the following trapping mechanisms[1]:

- Structural trapping below an impermeable, confining layer (cap rock);
- Residual trapping (retention as an immobile phase trapped in the pore spaces of the project reservoir);
- Solubility trapping (CO_2 dissolved into the fluids that saturate the pore space within a project reservoir);
- Mineralization trapping (precipitation as a carbonate material); and
- Adsorption onto organic matter in coal and shale (i.e., CO_2 bonds with geologic formation).

All emissions associated with storage operations, including vented and fugitive emissions at the injection site (after the injection meter) and from the subsurface, are accounted for in the project condition. All storage operations must comply with the terms of the AER Directive 065 approval.

Re-Injected Fluid

During extraction and production of oil and gas from the EOR scheme, some of the injected CO_2 returns to the surface in a free gas state or mixed with other hydrocarbons as solution gas. Once at the surface, the free CO_2 and the CO_2 in solution gas is separated from the oil and water in the separation process and the gas is re-injected ("recycled") into the storage complex via the injection wells. All CO_2 that returns to the surface as solution gas or as a free gas, which is released to the atmosphere either intentionally or unintentionally, must be accounted for in the emission offset project.

Different phases of development will involve a range of re-injection rates, typically increasing over time, and equipment must be sized appropriately to ensure permanent storage of CO_2. While injection in early years may consist of 100% new CO_2 (as opposed to re-injected CO_2), there will typically be a greater proportion of re-injected fluid in the later years of an EOR emission offset project.

Transferring CO_2 from one storage container to another storage container within the same Type 2 EOR scheme is allowed, on the condition that the emission offset project developer or EOR operator reports this accounting within the annual AER progress report. The offset project report must be clear, and transparently show it is an internal transfer within the scheme approval and not included in the determination of new CO_2 volumes.

Transferring CO_2 from one Type 2 EOR emission offset project to another EOR emission offset project is also allowed when specific conditions are met (see details in Section 1.4.5). The third-party assurance provider must fully review and provide comment on any CO_2 removals or transfers as part of their verification of the Report Balance Sheet for CO_2 (Appendix C).

The concentration of new CO_2 and the quantity injected into the emission offset project must be measured. Only new CO_2 injection is eligible to generate emission offsets. The venting or fugitive emissions from any re-injection (i.e. recycling or transferring) of CO_2 as well as the emissions associated with fuel use and electricity use and must be accounted for as project emissions.

Re-injection infrastructure may include measurement and gas analysis equipment, gas separation equipment, re-injection compression, valves, flow lines and piping.

---

[1] Part II: Carbon Capture and Geological Storage, International Petroleum Industry Environmental Conservation Association and American Petroleum Institute, June 2007

3.1. Identification of Project GHG Sources, Sinks and Reservoirs (SSRs)

All sources, sinks and reservoirs for the project condition were identified based on a review of existing best practice guidance contained in relevant greenhouse gas quantification protocols and enhanced oil recovery project configurations.

The process flow diagram provided in Figure 3 covers the SSRs within the full scope of project activities under this protocol. Process elements are further defined in Table 3. The project SSRs are organized into life cycle categories as shown in Figure 4. These SSRs are defined and classified as controlled, related or affected as described in Table 4.

Figure 3: Process Flow Diagram for the Project Condition

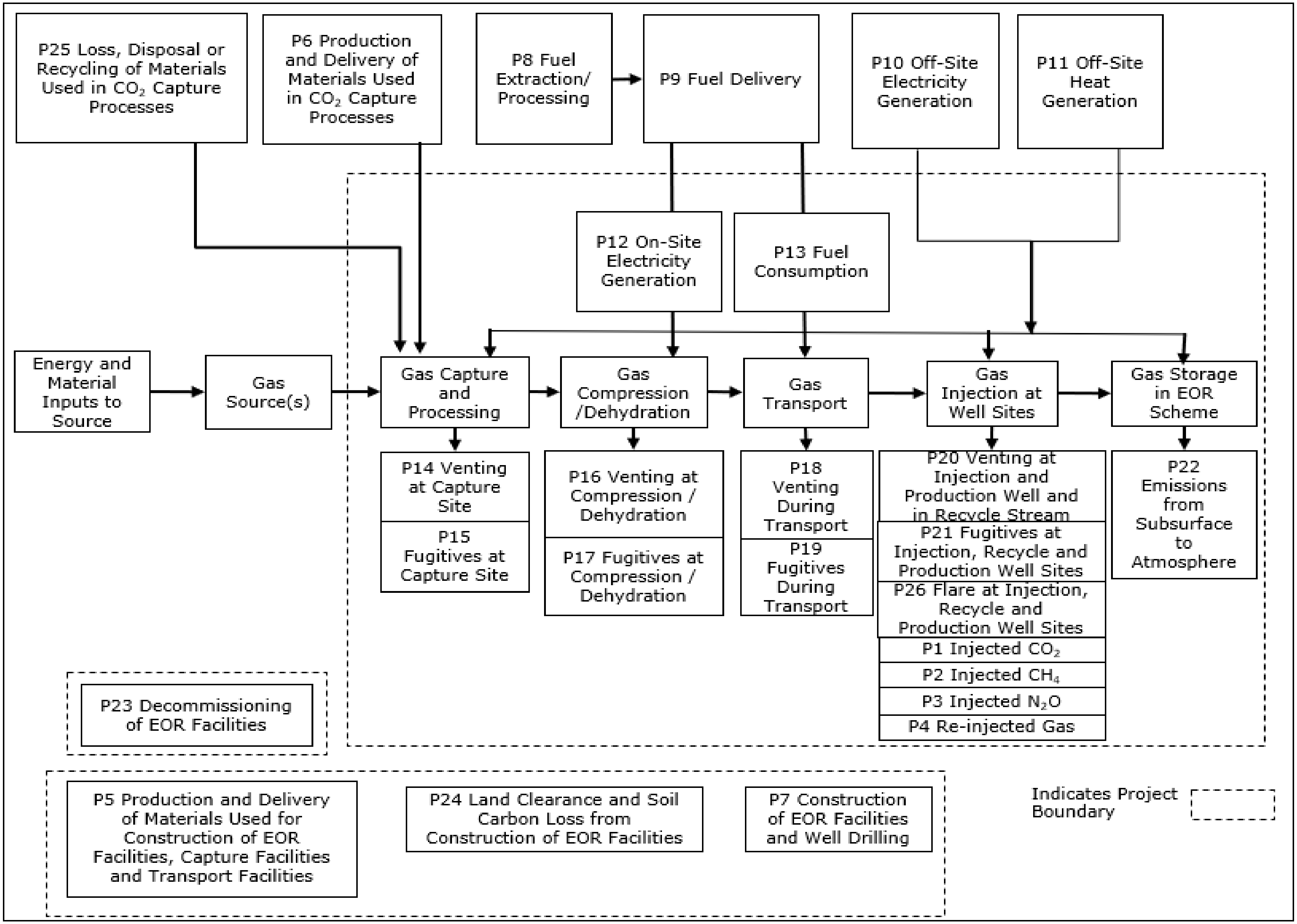


Table 3: Project Process Elements

Process Elements	Description
Energy and Material Inputs to Gas Source	Energy and material inputs to the gas source may include electricity, heat and fuel, which may be supplied from on-site or off-site sources.
CO_2 Source(s)	The source includes any type of process that generates CO_2-rich fluid, such as steam methane reforming from a GHG regulated facility in Alberta.
Capture and Processing	The CO_2-rich stream coming from the gas source may need further purifying and processing before it can be injected. The capture technology applied at the capture facility may use amine as a solvent to separate CO_2 from other components of the gas source.
Compression/Dehydration	The CO_2-rich stream is compressed before it can be transported to the CO_2 -EOR scheme. Dehydration may also be required to prevent hydrate formation. This may be achieved through heating or other processes.
Transport	The CO_2-rich stream will be transported to the injection site via pipeline, or CO_2 could be delivered by vehicle. Depending on the length of the pipeline or the location of capture facilities, additional booster compression may be needed.
Injection	The CO_2-rich stream will be injected at the EOR storage scheme, for example with the water-alternating-gas method. In certain cases, additional energy inputs may be required at the injection wells for the injection operation or to operate monitoring equipment.
Re-injected/ Recycled Fluid	Any injected fluid that comes back to surface as solution gas or free gas is recovered and re-injected (recycled), and additional compression may be required.
Gas Storage in EOR Scheme	The CO_2-rich stream will be injected in one or more project reservoirs suitable for permanent storage via EOR.

NOTE: Process elements are included for illustrative purposes only.

Figure 4: Project Condition SSRs

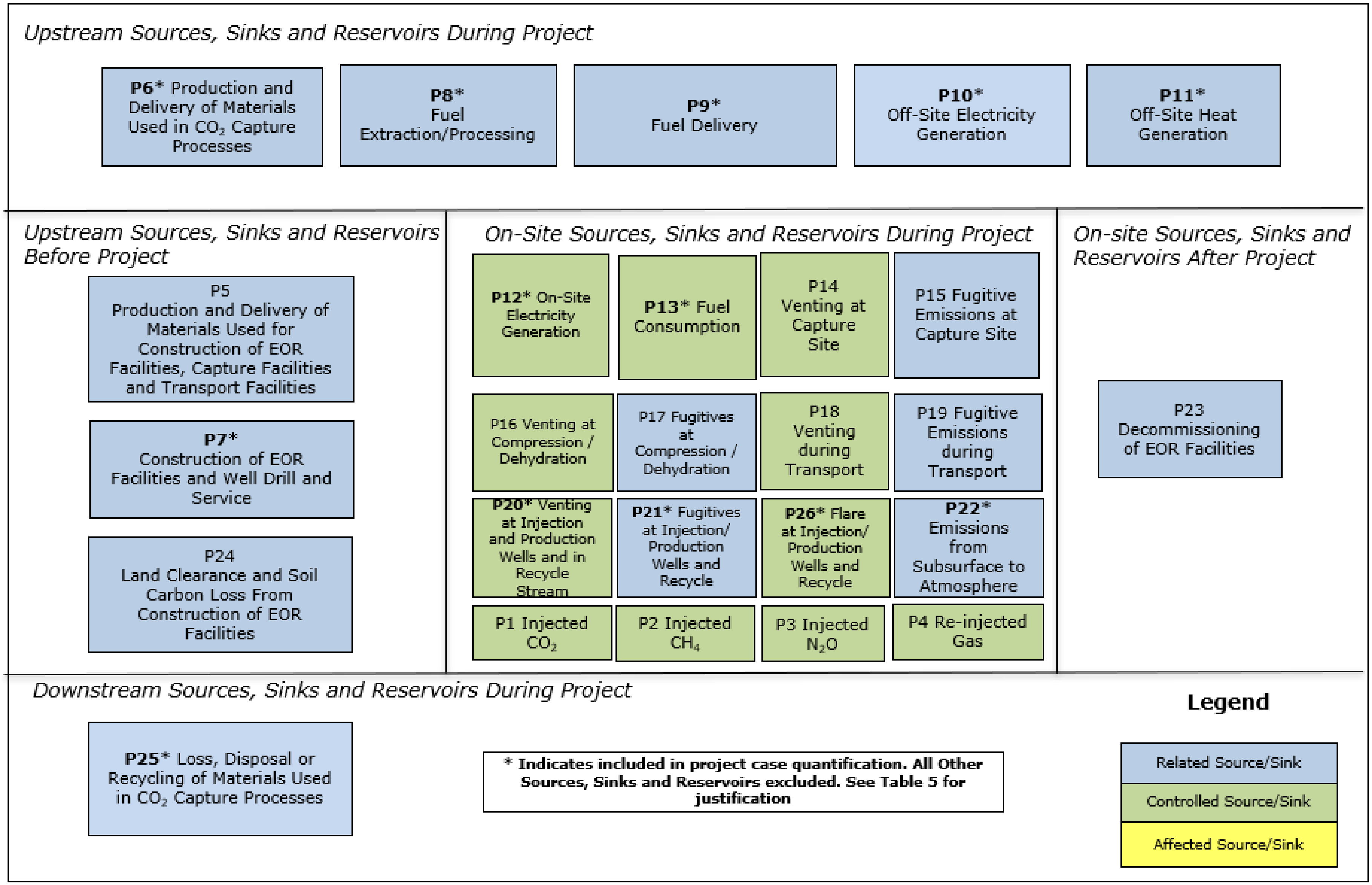


Table 4: Identification of Project Sources, Sinks and Reservoirs (SSR)

Source, Sinks and Reservoirs (SSRs)	Description	Controlled, Related or Affected
Upstream SSRs During Project Condition		
P6 Production and Delivery of Material Inputs used in CO_2 Capture Process	Material inputs for CO_2 capture and processing are required. These inputs may be specialized chemicals or additives such as amines. Greenhouse gas emissions are attributed to the fossil fuel consumption for transport of these materials, and the electricity and fossil fuel inputs for their production. The total aggregate quantity of each chemical delivered would be tracked.	Related
P8 Fuel Extraction/Processing	Each of the fuels used throughout the project will need to be sourced and processed. This will allow for the calculation of the greenhouse gas emissions from the various processes involved in the production, refinement and storage of the fuels. The total volumes of fuel for each of the SSRs are considered under this SSR. Volumes and types of fuels are the important characteristics to be tracked.	Related
P9 Fuel Delivery	Each of the fuels used throughout the project will need to be transported to the site. This may include shipments by tanker or by pipeline, resulting in the emissions of greenhouse gases. It is reasonable to exclude fuel sourced by taking equipment to an existing commercial fueling station as the fuel used to take the equipment to the sites is captured under other SSRs and there is no other delivery.	Related
P10 Off-site Electricity Generation	The total quantities of emissions associated with electricity imported and used by the capture facilities, the transport facility and the enhanced oil recovery injection and re-injection facilities must be tracked to estimate related greenhouse gas emissions.	Related
P11 Off-site Heat Generation	Emissions associated with generation of thermal energy off site. Off-site heat delivered to the emission offset project may have been generated independently.	Related
Upstream SSRs Before Project Condition		
P5 Production and Delivery of Materials Used for Construction of EOR Facilities, Capture Facilities and Transport Facilities	Materials used in the construction of carbon capture, transport and EOR facilities such as steel and concrete will need to be manufactured and delivered to the site. Emissions are attributed to fossil fuel and electricity consumption for material manufacture and fossil fuel consumption for material delivery.	Related
P7 Construction of EOR Facilities and Well Drill and Service	Site construction will require a variety of heavy equipment, smaller power tools, cranes, generators and well drilling operations. The operation of this equipment will have associated greenhouse gas emission from the use of fossil fuels and electricity and from the potential kick or blowout event that could release hydrocarbons during the drilling of injection and monitoring wells.	Related
P24 Land Clearing and Soil Carbon Loss from Construction of Enhanced Oil Recovery Facilities	The clearing of vegetative or forested land for site preparation may cause soil to release CO_2 into the atmosphere that was previously stored in soil.	Related

Source, Sinks and Reservoirs (SSRs)	Description	Controlled, Related or Affected
On-Site SSRs During Project Condition		
P1 Injected CO_2	The quantity of new CO_2 injected in the project and not released. This quantity is projected back to the baseline, from the project condition as CO_2 emissions released to the atmosphere, from the large emitter facility. The quantity of fluid is directly measured upstream of the injection wellheads and upstream of any re-injected (recycled) gas.	Controlled
P2 Injected CH_4	All CH_4 emissions released to the atmosphere in baseline, as projected from the project condition. Only baseline CO_2 emissions are projected, using direct measurement of the quantity of gas that is measured upstream of the injection wellheads in the project condition and upstream of re-injected (recycled) gas.	Controlled
P3 Injected N_2O	All N_2O emissions released to the atmosphere in baseline, as projected from the project condition. Only baseline CO_2 emissions are projected, using direct measurement of the quantity of gas that is measured upstream of the injection wellheads in the project condition and upstream of re-injected (recycled) gas.	Controlled
P4 Re-Injected (Recycled) Gas	All CO_2 that is produced from the EOR storage scheme and re-injected (recycled).	Controlled
P12 On-Site Electricity Generation	Electricity inputs may be required for CO_2 capture, compression, transportation, injection and re-injection. Electricity may be generated independently or from generation within the project boundary. The quantity and type of fuels consumed to generate electricity, and the quantity of electricity consumed by the project from each generating source would be tracked.	Controlled
P13 Fuel Consumption	Fuel use may be required for CO_2 capture, processing, compression, dehydration, transportation, injection and re-injection or for heat or electricity generation. The quantity and type of fuels consumed from each source would be tracked.	Controlled
P14 Venting at Capture Site	Some gases may be vented from the CO2 capture facilities during the project condition or during post offset project operations. CO2 venting may also be necessary for equipment maintenance or emergency shutdowns. These gases will be composed primarily of CO2 with trace amounts of other gases.	Controlled
P15 Fugitive Emissions at Capture Site	Unintended leaks of gas from the CO2 capture, measurement and processing unit may occur through faulty seals, loose fittings, or equipment.	Related
P16 Venting at Compression/Dehydration	Planned and emergency venting may be necessary for compressor and dehydrator maintenance and/or emergency shutdowns.	Controlled
P17 Fugitive Emissions at Compression/Dehydration	Unintended leaks of gas from the compressor and/or dehydrator may occur through seals, loose fittings, equipment, or compressor packing.	Related
P18 Venting during Transportation	Planned and emergency venting may be necessary for pipeline maintenance and/or shutdowns.	Controlled
P19 Fugitive Emissions during Transportation	Unintended leaks of gas from the CO_2 pipeline, transportation equipment, and additional compressors may occur through seals, loose fittings, equipment, or compressor packing. Include emissions from additional compression here only if they can't be separated out and accounted for under P15.	Related

Source, Sinks and Reservoirs (SSRs)	Description	Controlled, Related or Affected
P20 Venting at Injection and Production Wells and in Recycle Stream	Planned and emergency venting may be necessary for injection or production well work overs, in the handling of the recycle gas stream, for mechanical integrity checks, and maintenance. Instances of venting must be logged, including the duration of the venting event and the estimated quantities and makeup of gasses vented.	Controlled
P21 Fugitive Emissions at Injection, Recycle and Production Wells	Unintended or unplanned leaks of gas at the CO_2 injection wells or production wells and at CO_2 recycle facilities may occur through valves, flanges, piping, pipe connections, mechanical seals, or related equipment.	Related
P22 Emissions from Subsurface to Atmosphere	Accidental emissions to the atmosphere may occur from gas migration through undetected faults, fractures and/or subsurface equipment resulting from compromised casing, cement, wellhead, packer or tubing. Intentional releases or removals/transfers of CO_2 (when there is insufficient holdback) or net reversals are included here.	Related
P26 Flare at Injection/Production Wells and Recycle Stream	Planned and emergency flaring may be necessary for injection or production well sites or during work overs, mechanical integrity checks, re-injection stream flaring. These flare volumes and subsequent emissions are additional to baseline condition flaring due to EOR storage scheme oil production. Instances of project condition flaring is logged, including the duration of the flaring event, and sources of gases flared include any additional natural gas and the estimated quantities flared.	Controlled
On-Site SSRs After Project		
P23 Decommissioning of CO_2 Capture and Enhanced Oil Recovery Facilities	Infrastructure is decommissioned at the end of project operations. This involves the disassembly of the equipment, demolition of on-site structures, landfill disposal of some materials, environmental restoration, re-grading, planting or seeding, and transportation of materials off-site. Greenhouse gas emissions result from fossil fuels combustion and electricity use.	Related
Downstream SSRs During Project		
P25 Loss, Disposal, or Recycling of Materials Used in CO_2 Capture Processes	Material inputs are either disposed or recycled at the end of their useful life. Greenhouse gas emissions result from the transportation of materials to industrial landfill and/or material recycling processes. Emissions are also associated with the loss of material during project operation.	Related

4. Quantification

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

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

All SSRs are identified in Table 5 as included or excluded with justification for each is provided.

Table 5: Comparison of Sources, Sinks and Reservoirs (SSRs)

Identified SSRs		Baseline	Project	Include or Exclude	Justification
Upstream SSRs					
P6	Production and Delivery of Materials Used in CO_2 Capture Processes	N/A	Related	**Include**	This source may have a material impact on project emissions resulting from increased upstream chemical production associated with project period chemical usage.
B6	Production and Delivery of Materials Used in CO_2 Capture Processes	Affected	N/A	Exclude	Activity does not occur in the Baseline.
P8	Fuel Extraction/Processing	N/A	Related	**Include**	This source/sink may have a material impact on project emissions.
B8	Fuel Extraction/Processing	Related	N/A	Exclude	Activity for CO_2-EOR does not occur in the Baseline.
P9	Fuel Delivery	N/A	Related	**Include**	This source may have a material impact on project emissions.
B9	Fuel Delivery	Related	N/A	Exclude	Activity for CO_2-EOR does not occur in the Baseline.
P10	Off-Site Electricity Generation	N/A	Related	**Include**	This source may have a material impact on project emissions.
B10	Off-Site Electricity Generation	Related	N/A	Exclude	Activity for CO_2-EOR does not occur in the Baseline.
P11	Off-Site Heat Generation	N/A	Related	**Include**	This source may have a material impact on project emissions.
B11	Off-Site Heat Generation	Related	N/A	Exclude	Activity for CO_2-EOR does not occur in the Baseline.
P5	Production and Delivery of Materials Used in construction of EOR facility, capture facility and transport facility	N/A	Related	Exclude	This one-time only source of greenhouse gas emissions is negligible compared to the expected size and long lifetime of the project.
B5	Production and Delivery of Materials Used in construction of EOR facility, capture facility and transport facility	Affected	N/A	Exclude	This does not occur in Baseline.

Identified SSRs		Baseline	Project	Include or Exclude	Justification
P7	Construction of EOR Facilities and Well Drill and Service	N/A	Related	**Include***	*Include Reportable Drilling Releases Only The construction of EOR facilities is a one-time only source of greenhouse gas emissions and is negligible compared to the expected size and long lifetime of the project. *Any drilling releases that trigger Alberta Energy Regulator's Directive 059 reporting threshold for kicks or blowouts must be included in the project emissions.
B7	Construction of EOR Facilities and Well Drill and Service	Affected	N/A	Exclude	Activity for EOR does not occur in Baseline.
P24	Land Clearance and Soil Carbon Loss from Construction of EOR Facilities	N/A	Related	Exclude	This one-time only source of greenhouse gas emissions is negligible compared to the expected size and long lifetime of the project.
B24	Land Clearance and Soil Carbon Loss from Construction of EOR Facilities	Affected	N/A	Exclude	
On-site SSRs					
P1	Injected CO_2	Controlled	N/A	Exclude	Project condition is projected to baseline condition.
B1	Injected CO_2	N/A	Controlled	**Include**	This is the project activity of injection of new CO_2 from a large emitter for use in EOR emission offset project.
P2	Injected CH_4	Controlled	N/A	Exclude	The injected CH_4 is not eligible to be quantified as injected CO_2 as it is also a fuel.
B2	Injected CH_4	N/A	Controlled	Exclude	No emission reduction allowed for the injection of CH_4.
P3	Injected N_2O	Controlled	N/A	Exclude	The injected nitrous oxide is not eligible to be quantified as injected CO_2, as it is a product of incomplete separation.
B3	Injected N_2O	N/A	Controlled	Exclude	No emission reduction allowed for the injection of N_2O
B4	Re-Injected Fluid	Controlled	N/A	Exclude	Activity for EOR does not occur in Baseline.
P4	Re-injected Fluid	N/A	Controlled	Exclude	The emissions from this source have been accounted for by installing the meter for B1 to the injection point but prior to the point where re-injected (recycled) gas enters the gas stream.
P12	On-Site Electricity Generation	N/A	Controlled	**Include**	This source may have a material impact on project emissions.

Identified SSRs		Baseline	Project	Include or Exclude	Justification
B12	On-Site Electricity Generation	Controlled	N/A	Exclude	Activity for EOR does not occur in Baseline.
P13	Fuel Consumption	N/A	Controlled	**Include**	This source may have a material impact on project emissions.
B13	Fuel Consumption	Controlled	N/A	Exclude	Activity for EOR does not occur in Baseline.
P14	Venting at Capture Site	N/A	Controlled	Exclude	The emission source is accounted for by the large emitter that supplies the CO_2.
B14	Venting at Capture Site	Controlled	N/A	Exclude	Activity for EOR does not occur in Baseline.
P15	Fugitive Emissions at Capture Site	N/A	Related	Exclude	The emission source is accounted for by the large emitter that supplies the CO_2.
B15	Fugitive Emissions at Capture Site	Related	N/A	Exclude	Activity for EOR does not occur in Baseline.
P16	Venting at Compression/Dehydration	N/A	Controlled	Exclude	The emission source is accounted for by the large emitter that supplies the CO_2.
B16	Venting at Compression/Dehydration	Controlled	N/A	Exclude	Activity for EOR does not occur in Baseline.
P17	Fugitives at Compression/Dehydration	N/A	Related	Exclude	The emission source is accounted for by the large emitter that supplies the CO_2.
B17	Fugitives at Compression/Dehydration	Related	N/A	Exclude	Activity for EOR does not occur in Baseline.
P18	Venting during Transport	N/A	Controlled	Exclude	The emission source is accounted for by the large emitter that supplies the CO_2.
B18	Venting during Transport	Controlled	N/A	Exclude	Activity for EOR does not occur in Baseline.
P19	Fugitive Emissions during Transport	N/A	Related	Exclude	The emission source is accounted for by the large emitter that supplies the CO_2.

Identified SSRs		Baseline	Project	Include or Exclude	Justification
B19	Fugitive Emissions during Transport	Related	N/A	Exclude	Activity for EOR does not occur in Baseline.
P20	Venting at Injection/ Production Wells and in Recycle Stream	N/A	Controlled	**Include**	This source/sink must be included because it may occur downstream of the injection meter. Resulting emissions may have material impact on project emissions.
B20	Venting at Injection/ Production Wells and Recycle	Controlled	N/A	Exclude	Activity for EOR does not occur in Baseline.
P21	Fugitive Emissions at Injection/Production Wells and Recycle	N/A	Related	**Include**	This source/sink must be included because it may occur downstream of the injection meter. Resulting emissions may have material impact on project emissions.
B21	Fugitive Emissions at Injection/Production Wells and Recycle	Related	N/A	Exclude	Activity for EOR does not occur in Baseline.
P22	Emissions from Subsurface to Atmosphere	N/A	Related	**Include**	This source must be included because it may occur downstream of the injection meter. Resulting emissions may have material impact on project emissions.
B22	Emissions from Subsurface to Atmosphere	Related	N/A	Exclude	Activity for CO_2EOR does not occur in Baseline.
P23	Decommissioning of Enhanced Oil Recovery Facilities	N/A	Related	Exclude	This source results in negligible greenhouse gas emissions compared to the expected size and long lifetime of the project.
B23	Decommissioning of Enhanced Oil Recovery Facilities	Related	N/A	Exclude	The emissions from this activity are negligible relative to total project emissions and reductions.
P26	Flare at Injection/Production Wells and Recycle	N/A	Controlled	**Include**	This source must be included because it may occur downstream of the injection meter. Resulting emissions may have material impact on project emissions.
B26	Flare at Injection/Production Wells and Recycle	Controlled	N/A	Exclude	Activity for EOR does not occur in Baseline.
Downstream SSRs					
P25	Loss, Disposal, or Recycling of Materials Used in CO_2 Capture Processes	N/A	Related	**Include**	Resulting emissions may have material impact on project emissions.
B25	Loss, Disposal, or Recycling of Materials Used in CO_2 Capture Processes	Affected	N/A	Exclude	Activity for CO_2-EOR does not occur in Baseline.

4.1. Quantification Methodology

The quantification methodology includes net emission reductions and offset-eligible emission reductions. as well as, in the event where it applies, methodology for any priced emission reductions. In some projects, some SSRs 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 SSRs are subject to a carbon price and whether or not to include them in offset-eligible or as a priced emission reduction, depending on the project and the regulatory status of the site at which the project is implemented. Regardless, the net geological sequestration as a result of this emission offset project is quantified by calculating associated emissions and CO_2 geological sequestration from included SSRs in both the baseline and project conditions and calculating the difference. Table 6 outlines the required quantification methodology for application of this protocol.

Quantification of the emissions, reductions, removals and reversals of relevant SSRs for each of the greenhouse gases must be completed using the quantification procedures outlined below. These quantification procedures serve to complete the following equations for calculating the emission reductions based on the comparison of the baseline and project conditions.

Essential to the quantification is an understanding and appropriate treatment of carbon pricing, either federal and/or provincial, on the calculation of the offset eligible emission reductions. Emissions and reductions that are not subject to a carbon price or surcharge (or exempt from a carbon price) are eligible for emission offsets. Facilities regulated under Alberta's Regulation are exempt from the federal fuel charge and CO_2 exported from the regulated large emitter or opt-in facilities is eligible to be sequestered and generate emission offsets. Emissions and reductions that are subject to a carbon price or surcharge are not eligible for emission offsets. Projects that quantify emission offsets must quantify and report non-offset eligible emissions and reductions as applicable to the project activity.

Projects must identify and categorize all baseline and project emission SSRs included in the quantification as either "priced" or "non-priced" sources of emissions based on applicable Federal and/or Provincial legislation that is in place during the reporting period covered by the offset project report. Priced emission sources are to be reported but are not included in the calculation of emission offsets. Net geological sequestrations are calculated based on the difference between eligible Baseline and Project quantification.

4.2. Net Geological Sequestration

Outlined below is the general approach to quantifying the net geological sequestration for the project activities.

Project Statement

The following items must be listed separately in the Project Report and itemized by reporting period and by vintage year

- **Discounted Emission Reductions** = *Emissions* $_{Baseline}$ × *Discount Factor (Df)*

- **Holdback Emission Reductions** = *Emissions* $_{Baseline}$ × *Holdback Factor (Hf)*

- **Net Geological Sequestration** = *Emissions* $_{Baseline}$ − *Emissions* $_{Project}$ − *Discounted Emission Reductions* − *Holdback Emission Reductions*

Df = Discount applied to injected CO_2 for unintentional reversals. Set equal to 0.005

Hf (Hf_1 or Hf_2) = Holdback applied to injected CO_2 to set aside emission offsets for potential future reversal(s) for a Type 1 or Type 2 CO_2-EOR Storage Scheme.

Holdback (H_1) = 0 for emission offset project crediting period year 1, 2, 3 and 4 inclusive; then 0.02 for year 5 onward for each reporting period, including extensions, for Type 1 EOR schemes;

Holdback (H_2) = 0.5 for all reporting periods for Type 2 EOR schemes.

Note: The Holdback is considered to be a future Net Geological Sequestration assuming the holdback criteria are satisfied.

Baseline emissions are calculated according to the following, which is in alignment with the Baseline SSRs listed as “included” in Table 5:

Baseline emissions are calculated according to the following:		
$\text{Emissions}_{\text{Baseline}}$	=	$\text{Emissions}_{\text{Injected CO2}} – CO_2\,_{\text{injected originating within project boundary}}$
Baseline emission sources include the following:		
$\text{Emissions}_{\text{Baseline}}$	=	sum of emissions projected from the measured quantity and concentration of CO_2 injected in the project condition but does not include CH_4, N_2O or re-injected (recycled or transferred) CO_2.
$\text{Emissions}_{\text{Injected CO2}}$	=	sum of emissions under B1 Injected CO_2
CO_2 injected originating within project boundary	=	portion of injected CO_2 that is sourced from within the defined physical or operational boundary of the emission offset project from fuel combustion. This does not include newly captured CO_2 from external sources and is excluded from baseline emissions to avoid overstating the net impact.

Project emissions are calculated according to the following:

$$\text{Emissions}_{\text{Project}} = \text{Emissions}_{\text{Production and Delivery of Materials used in CO2 Capture Process}} + \text{Emissions}_{\text{Construction of EOR Facilities and well drill and service}} + \text{Emissions}_{\text{Fuel Extraction and Processing}} + \text{Emissions}_{\text{Fuel Delivery}} + \text{Emissions}_{\text{Off-Site Electricity Generation}} + \text{Emissions}_{\text{Off-Site Heat Generation}} + \text{Emissions}_{\text{On-Site Electricity Generation}} + \text{Emissions}_{\text{Fuel Consumption}} + \text{Emissions}_{\text{Venting at Injection and Production Wells}} + \text{Emissions}_{\text{Fugitive at Injection and Production Wells and Recycle}} + \text{Emissions}_{\text{Subsurface to AtmosphereReversal}} + \text{Emissions}_{\text{Loss, Disposal or Recycling of Material Inputs}} + \text{Emissions}_{\text{Flare at Injection/Production Wells and Recycle}}$$

Project emission sources include the following:

$\text{Emissions}_{\text{Project}}$ = sum of emissions under the project condition
= emissions under P6 Production and Delivery of Materials used in construction of EOR facility, capture facility and transport facility
\+ emissions under P7 Production and Construction of EOR Facilities and well drill and service
\+ emissions under P8 Fuel Extraction/ Processing
\+ emissions under P9 Fuel Delivery
\+ emissions under P10 Off-Site Electricity Generation
\+ emissions under P11 Off-Site Heat Generation
\+ emissions under P12 On-Site Electricity Generation
\+ emissions under P13 Fuel Consumption
\+ emissions under P20 Venting at Injection and Production Wells and in Recycle Stream
\+ emissions under P21 Fugitive at Injection, Recycle and Production Wells
\+ emissions under P22 Emissions from Subsurface to Atmosphere
\+ emissions under P25 Emissions from Loss, Disposal or Recycling of Materials Inputs
\+ emissions under P26 Flare at injection/production wells and recycle stream
\- (minus) CO2 injected originating within project boundary

CO_2 injected originating within project boundary is included in project emissions through quantification of fuel use within the project and in baseline emissions through metering of injected volumes. These cancel and no explicit quantification is required for this emission category.

$$\text{Total } CO_2e \text{ Equivalent Emissions} = \sum (CO_2 \text{ emissions}) + \sum (CH_4 \text{ emissions})*GWP_{CH4} + \sum (N_2O \text{ emissions})* GWP_{N2O}$$

Where:

CO_2e Equivalent Emissions = sum of all greenhouse gas emissions converted to CO_2 equivalent terms, and does not apply to injected quantities of CH_4 or N_2O.

GWP = Global Warming Potential for each greenhouse gas as listed in Standard for Completing Greenhouse Gas Compliance and Forecasting Reports.

4.3. Offset Eligible Emission Reductions (non-priced emissions)

As applicable, 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 that quantify offset eligible emission reductions must also quantify and report on priced emission reductions as per section 4.3.1.

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

4.3.1. Priced Emission Reductions

Emissions that are subject to a carbon price are not eligible for emission offsets. Projects 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 SSRs that are subject to a carbon price. Some emissions 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 SSRs that are subject to a carbon price are included in the quantification of priced emission reductions.

Table 6: Quantification Procedures

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
Baseline SSRs						
B1 Injected CO_2 (volumetric or mass flow measurement)	**Where: Volumetric flow measurement is used:** **Emissions Injected CO_2 = ∑ *(Vol. Injected Gas * % CO_2 * ρCO_2)*** **Where: Mass flow measurement is used:** **Emissions Injected CO_2 = ∑ *(Mass Fraction CO_2, normalized * Mass $_{Gas}$)***					
	Emissions $_{\text{Injected CO2}}$	t of CO_2e	Measured	This value refers to the injected quantity of CO_2 measured at the metering point in the project condition. The measured volume, concentration, temperature and pressure are used to calculate the mass of CO_2e (excludes CH_4 and N_2O)	N/A	Mass of CO_2 to be calculated from direct measurement, corrected for temperature and presure of flow, and from the CO_2 concentration
	Volume of injected fluid / Vol. $_{\text{Injected Fluid}}$	e^3m^3	Measured	Direct metering of volume of gas measured at the metering point in the project condition, as close as practical to injection but prior to re-injected fluid injection point	Continuous metering	Direct metering is standard practice Frequency of metering is highest level possible
	Density of CO_2 / ρ_{CO2}	kg/m^3 or t/e^3m^3	Estimated	Must use a reference density, corrected to the conditions at which the volumes of gas are reported. Data conversions from all pressure and temperature compensated instruments must be sure to use the same pressure or temperature used for the specific meter calibration	Calculated Daily	Densities must be used consistently throughout project
	Concentration of injected CO_2 / % $_{\text{Injected CO2}}$	%Volume/% Mole	Measured	The CO_2 concentration must be directly measured downstream of the capture and processing equipment or upstream of the injection field at a custody transfer point. When additional CO_2 streams comingle with a capture stream of known concentration, the concentration of the comingled stream must be confirmed either by direct measurement of the comingled stream or by mass balance and a measurement of the additional	Continuous At minimum, a sample every three hours averaged daily on a volumetric basis for emission offset	Direct metering is standard practice Frequency of metering is highest level possible (See Standard Standard for Validation, Verification and Auditfor information on total error allowed in verification statements)

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
				capture stream. The measurement sample point may occur down-stream of the tie in such that the concentration of the comingled stream is taken. Alternatively, the measurement can be taken down-stream of the additional capture stream but upstream of comingling. In this case, the concentration of the comingled stream can be calculated by solving a single variable mass balance equation.	projects subject to a 2 % materiality threshold	A minimum of one monthly sample to allow weighted average, on volumetric basis, to be used for emission offset projects subject to 5% materiality threshold
	$Mass_{Gas}$	Tonnes	Measured	Direct metering of mass of gas measured at the metering point in the project condition over the reporting period, measured directly at each injection well	Continuous metering	Direct metering is standard practice Frequency of metering is highest level possible.
	$Mass\ Fraction_{CO2,\ normalized*}$	%	Measured	The CO_2 mass fraction must be directly measured downstream of the capture and processing equipment or upstream of the injection field at a custody transfer point. When additional CO_2 streams comingle with a capture stream of known concentration, the concentration of comingled stream must be confirmed either by direct measurement of the comingled stream or by mass balance and a measurement of the additional capture stream. The measurement sample point may occur downstream of the tie in such that the concentration of the comingled stream is taken. Alternatively, the measurement can be taken downstream of the additional capture stream but upstream of comingling. In this case, the concentration of the comingled stream can be calculated by solving a single variable mass balance equation. * Note: normalization of the mass fraction of CO_2 requires measurement of other	Daily	The mass fraction of CO_2 is dependent upon the mass fraction of all components in the stream If components totaling 99.5% of mass fraction are measured, the unmeasured components should have an immaterial effect on injected CO2

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
				components that sum to at least 99.5% of the known components in the stream.		
Project SSRs						
P6 Production and Delivery of Material Inputs used in CO_2 Capture Process	**Emissions $_{\text{Production \& Delivery of Material Inputs}}$ = ∑ (Input $_i$ * EF Input $_{i\ CO2,\ CH4,\ N2O}$)**					
	Emissions $_{\text{Production \& Delivery of Material Inputs}}$	t CO_2e	N/A	N/A	N/A	Quantity being calculated in aggregate based on quantity of inputs used throughout the carbon capture operations
	Quantity of material inputs consumed for carbon capture facility operation / Input $_i$	tCO_2e / L / m^3 / Other	Estimated	Estimation of the quantity of material inputs consumed for the carbon capture and CO2 storage processes	Annual or by reporting period	Procurement records or an engineering report will specify the quantity of material input required for an appropriately sized carbon capture facility Represents most reasonable means of estimation
	Emissions factor for each type of material input / EF Input $_{i\ CO2,\ CH4,\ N2O}$	tCO_2e per t / L e^3m^3 / other	Estimated	Project specific design	Annual	Production and delivery estimates for the emission factors for the material inputs
P7 Construction of EOR Facilities and Well Drill and Service	**Emissions $_{\text{Drill and Service Injection Well Sites}}$ = ∑ (Vol. $_{\text{Gas Kick}}$ * % $_{i\ CO2,\ CH4,\ N2O}$ * ρ $_{i\ CO2,\ CH4,\ N2O}$) * GWP $_{CH4,\ N2O}$**					
	Emissions $_{\text{Venting at Wells}}$	tCO_2e	N/A	N/A	N/A	Quantity being calculated
	Volume of Vented Gas / Vol. $_{\text{Gas Kick}}$	e^3m^3	Estimated	If the drilling or service activity resulted in a kick or a blowout, Directive 59 submission is triggered The values submitted in the Directive 59 report should be used to estimate the volume of gas released. (May be a vented or fugitive emission)	Engineering estimate per event	The measurement approach should follow Directive 059 instructions and should be as frequent as the event
	Concentration of gas vented **/ %** $_{i\ CO2,\ CH4,\ N2O}$	% volume	Measured	A measured gas analysis should be obtained	N/A	The measurement approach should follow Directive 059 instructions and should be as frequent as the event

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Density of vented gas / $\rho_{i\ CO2,\ CH4,\ N2O}$	t/e^3m^3	Estimated	Site specific, based on gas analysis. If not possible, must use a reference density, corrected to the conditions at which the volumes of gas are reported. Data conversions from all pressure and temperature compensated instruments must be sure to use the same standard temperature and pressure (STP) used for the specific meter calibration.	N/A	Densities must be used consistently throughout emission offset project
	$GWP_{CH4,\ N2O}$ Global Warming Potential	Unitless	Estimated	As per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Published standard
P8 Fuel Extraction and Processing	**Emissions $_{Fuel\ Extraction\ and\ Processing}$ = $\sum$ (Fuel Used $_i$ * EF Fuel $_{i\ CO2,\ CH4,\ N2O}$) * GWP $_{CH4,\ N2O}$**					
	Emissions $_{Fuel\ Extraction\ and\ Processing}$	tCO_2e	N/A	N/A	N/A	Quantity being calculated in aggregate based on quantity of fossil fuels used at each component of the CO_2-EOR scheme operations (Capture, Transport and Storage/Recycle) Excludes consumption pertaining to oil and gas production from the EOR scheme itself
	Total quantity of fossil fuels consumed to operate each component of the CO_2-EOR storage scheme operations (Capture, Transport and Storage/Recycle)/ Vol. Fuel Used	e^3m^3/M / Other	Measured	Direct measurement of the quantity of fossil fuels consumed at each component of the carbon capture and storage project Where direct measurement is not available proration of fuel to specific equipment based on total fuel metering is acceptable	Continuous metering or monthly reconciliation or allocation	Both methods are standard practice Allocation of metered quantities is permitted (i.e., to separate out emissions for oil handling, etc.) 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
	Emissions factors for extraction and processing of each type of fuel / EF Fuel $_{i\ CO2,\ CH4,\ N2O}$	tCO_2e per e^3m^3 / MJ/ other	Estimated	Carbon Offset Emission Factors Handbook	Annual	Reference values represent best available emission factors for fuel extraction and processing
	$GWP_{CH4,\ N2O}$ Global Warming Potential	Unitless	Estimated	Per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Published standard
P9 Fuel Delivery	**Emissions $_{Fuel\ Delivery}$ = ∑ (Fuel Used $_i$ * EF Used $_{i\ CO2,\ CH4,\ N2O}$) * GWP $_{CH4,\ N2O}$**					
	Emissions $_{Fuel\ Delivery}$	tCO_2e	N/A	N/A	N/A	Quantity being calculated in aggregate based on quantity fuel used
	Quantity of Fuel Used to operate each component of the CO_2-EOR storage scheme operations (Capture, Transport and Storage/Recycle)/ Vol. Fuel Used $_i$	L/ e^3m^3/ Other	Calculated	Direct measurement of the quantity of fossil fuels consumed at each component of the carbon capture and storage project Where direct measurement is not available proration of fuel to specific equipment based on total fuel metering is acceptable	Continuous metering or monthly reconciliation or allocation	Both methods are standard practice Allocation of metered quantities is permitted (i.e., to separate out emissions for oil handling, etc.) Frequency of metering is highest level possible/ Frequency of reconciliation provides for reasonable diligence
	Emissions factor for each type of fuel consumed in transport of fuel / EF Used $_{i\ CO2,\ CH4,\ N2O}$	t CO_2e per L / e^3m^3 /other	Calculated	Per Carbon Offset Emission Factors Handbook	Annual	Production and delivery estimates for the emission factors for the material inputs
	$GWP_{CH4,\ N2O}$ Global Warming Potential	Unitless	Estimated	Per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Published standard
P10 Off-Site Electricity Generation	**Emissions Off-Site Electricity Generation = Electricity import* EF Electricity** **EF electricity = Carbon Offset Emission Factors Handbook (use increased on-site grid electricity use (includes line loss))**					

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Emissions $_{Off\text{-}Site\ Electricity\ Generation}$	tCO_2e	N/A	N/A	N/A	Total off-site electricity emissions quantity being calculated based on the quantity of electricity sourced from outside the project
	Total quantity of delivered electricity consumed for the emission offset project / Electricity $_{import}$	MWh	Measured	Direct measurement of electricity delivered to the emission offset project including as appropriate the capture, compression, transport, injection and storage of CO2. The total electricity consumption should be calculated as the sum of individual import meters if there are more than one.	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail
	Emission intensity factor for electricity generation / EF $_{electricity}$	tCO_2e / MWh	Estimated	Grid emission intensity factor for each year obtained from the Carbon Offset Emission Factors Handbook. For the vintage years 2025 through 2029 the TIER high-performance benchmark for electricity for that year may be used.	Annual	Reference value adjusted periodically
P11 Off-Site Heat Generation	**Emissions Off-Site Heat Generation = Heat * EF $_H$** Where: **EF $_H$ = Industrial Heat Benchmark**					
	Emissions $_{Off\text{-}Site\ Heat\ Generation}$	tCO_2e	N/A	N/A	N/A	Quantity being calculated based on total quantity of heat sourced from off site Sources from a regulated facility and from an industrial facility not regulated are included
	Quantity of heat consumed by the emission offset project / Heat	GJ	Measured	Direct measurement of the quantity of heat used by the CO_2-EOR emission offset project	Continuous metering	Continuous metering is standard for boundary transfer
	Benchmark for Industrial Heat Generation/ EF $_H$	tCO_2e / GJ	N/A	Regulated facilities that export thermal energy to another regulated facility, a CCS emission offset project or an EOR emission offset project account for it at the TIER benchmark for industrial heat	Annual	Established industrial heat high-performance benchmark as listed in TIER Regulation or through Ministerial Order must be used in all cases

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
P12 On-Site Electricity Generation	**Emissions On-Site Electricity Generation = Σ (Fuel EOR * EF Fuel i, CO2, CH4, N2O) * GWP CH4, N2O** Where: **Fuel EOR = (Elec EOR / Elec T)* Fuel E** If the Emission intensity factor associated with heat from the emission offset project is not exporting electricity or is using electricity for oil handling, water treatment or for non-project purposes and there is no other reason to separately report P12 On-site electricity generation, the fuel can be accounted for in P13 Fuel Consumption.					
	Emissions On-Site Electricity Generation	t of CO_2e	N/A	N/A	N/A	Quantity being calculated based on quantity of power sourced from on-site electricity generation facilities
	Proportionate quantity of Fossil Fuels Consumed to Generate Power at On-Site Generation Facilities for Use by the EOR emission offset project / Fuel EOR	L/ e3m3/ Other	Calculated	Calculated relative to the metered quantities of electricity delivered to the CO2-EOR scheme from connected power generation facilities	Monthly	Allocation of Project Emissions based on proportion of total energy output from the electricity generation unit that is supplied to the enhanced oil recovery emission offset project is appropriate given that multiple energy users may source electricity from a power plant. Direct metering of electricity is appropriate
	Proportionate Volume of Fossil Fuels Consumed to Generate Heat and Power at On-Site Generation Facilities for Use by the CCS Project / Fuel CCS	L/ m^3/ Other	Calculated	Calculated relative to the metered quantities of thermal energy and electricity delivered to the carbon capture and storage project from connected heat and power generation facilities	Monthly	Allocation of Project Emissions based on proportion of total energy output from the combustion unit that is supplied to the carbon capture and storage project is appropriate given that multiple energy users may source thermal energy or electricity from a single combined heat and power plant. Direct metering of thermal energy and electricity is appropriate.
	Quantity of Fossil Fuels Consumed to Generate Electricity at On-Site Generation Facilities for Use by	L/ e3m3/ Other	Measured	Direct measurement of the volume of fossil fuels consumed at power generation facility and/or other direct connected facilities that provide power to the emission offset project	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	the EOR emission offset project / Fuel E					
	Emissions Factor for Combustion of Each Type of Fuel /EF Fuel i, CO2, CH4, N2O	t CO2 per L / e3m3 / other	Estimated	Carbon Offset Emission Factors Handbook	N/A	Must use most current factors published
	Total Quantity of Electricity Supplied to End Users by the Generation Facility in the Project Condition / Elec T	GJ	Measured	Direct metering of quantity of electricity delivered to all direct connected facilities from the generation plant; including the direct metering of the total electricity distributed to emission offset project, the regional electricity grid and an industrial system designation	Continuous Metering	Continuous direct metering represents the industry practice and the highest level of detail
	GWPCH4, N2O Global Warming Potential	Unitless	N/A	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
P13 Fuel Consumption	**Emissions $_{Fuel\ Consumption}$ =** **$[\sum(Vol.\ Fuel_i * EF\ Used_{i\ CO2}) + \sum(Vol.\ Fuel_i * EF\ Used_{i\ CH4} * GWP_{CH4}) + \sum(Vol.\ Fuel_i * EF\ Used_{i\ N2O} * GWP_{N2O})]/1000$**					
	Emissions $_{On\text{-}Site\ Fuel\ Consumption}$	tCO_2e	N/A	N/A	N/A	Quantity being calculated in aggregate based on quantity and type of fuel used
	Quantity Fuel Used for On-Site Fuel Consumption $_i$	L/ m^3/ Other	Measured	Calculated based on measurement of the quantity of each of the fuels used on-site	Continuous metering or monthly reconciliation or allocation	Both methods are standard practice Allocation of metered quantities is permitted (i.e., to separate out emissions for oil handling, etc.) Frequency of metering is highest level possible. Frequency of

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
						reconciliation provides for reasonable diligence
	CO_2 Emissions Factor for Combustion of Each Type of Fuel / EF Used $_{i\ CO2}$	kg CO_2 per L / m^3 / other	Estimated	Carbon Offset Emission Factors Handbook	N/A	Must use most current factors published
	CH_4 Emissions Factor for Combustion of Each Type of Fuel / EF Used $_{i\ CH4}$	kg CH_4 per L / m^3 / other	Estimated	Carbon Offset Emission Factors Handbook	N/A	Must use most current factors published
	N_2O Emissions Factor for Combustion of Each Type of Fuel / EF Used $_{i\ N2O}$	kg N_2O per L / m^3 / other	Estimated	Carbon Offset Emission Factors Handbook	N/A	Must use most current factors published
	GWP for CH_4, N_2O Global Warming Potential	Unitless	Estimated	Per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	As published
P20 Venting at Injection and Production Wells and in Recycle Stream	**Emissions $_{\text{Venting at Injection, Production Wells and Recycle Stream}}$ = $\sum$ (Vol. $_{\text{Gas Vented}}$ * % $_{\text{CO2, CH4, N2O}}$ * $\rho_{\text{CO2, CH4, N2O}}$ *GWP $_{\text{CO2, CH4, N2O}}$)**					
	Emissions $_{\text{Venting at Injection, Production Wells and Recycle Stream}}$	tCO_2e	N/A	N/A	N/A	Quantity being calculated
	Volume of Vent Gas / Vol. $_{\text{Gas Vented}}$	L / e^3m^3 / other	Estimated	Volume should be estimated as per the Alberta Quantification methodologies for the Technology Innovation and Emissions Reduction Regulation and the Specified Gas Reporting Program and based on the pressure, length and diameter of the pipe being serviced	Per event	This vented gas is downstream of the injection meter during maintenance blowdowns and should be determined as frequent as the maintenance event
	Concentration in Vent Gas / % $_{\text{CO2,CH4,N2O}}$	%	Measured	The CO_2 concentration shall be directly measured during the event where possible. Otherwise, operations data will be needed for an engineering estimate	A minimum of daily samples per	CO_2 concentration may vary throughout the injection or re-cycle stream

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
					event, when possible	Otherwise, estimated composition of the vented gas based on its source
	Density of Vent Gas / $\rho_{CO2,CH4,N2O}$	t / e^3m^3	Estimated	Site specific, based on gas analysis. If not possible, must use a reference density, corrected to the conditions at which the volumes of gas are reported Data conversions from all pressure and temperature compensated instruments must be sure to use the same standard temperature and pressure (STP) used for the specific meter calibration	N/A	Densities must be used consistently throughout project
	$GWP_{CO2,CH4,N20}$	Unitless	Estimated	Per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	As published
P21 Fugitives at Injection/ Production Wells and Recycle Stream	**Emissions** $_{\text{Fugitives at Injection/Production Well and Recycle Stream}}$ **=** **∑ (Fitting** $_i$ *** ER** $_{\text{Fitting } i}$**) + Other Fugitive Releases**					
	Emissions $_{\text{Fugitives at Injection/Production Well and Recycle Stream}}$	tCO_2e	N/A	N/A	N/A	Quantity being calculated
	Other Fugitive Releases	tCO_2	Estimated	Engineering estimate	Per occurrence Estimated based on the most detailed information available	This is from unintended/unplanned events, and accounts for CO_2 released after the meter but not from the storage complex
	Number of Fittings after Metering Point / Fitting $_i$	N/A	Estimated	Emission offset project specific design	Once	Estimated based on the number of fittings after the injection meter, piping and re-injection equipment above the subsurface
	Emission Rate for Fitting and Equipment leaks / ER $_{\text{Fittings Equip } i}$	tCO_2e /year	Calculated	Emission rate based on industry best practices for determining emissions based on actual field equipment and	Annual	Estimates made for project specifics represent the most accurate means

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
				LDAR Measurement (using operating pressures and gas properties)		
P22 Emissions from Subsurface to Atmosphere	**$\text{Emissions}_{\text{Subsurface to Atmosphere}} = \text{Mass } CO_{2\ \text{leaked}}$**					
	$\text{Emissions}_{\text{Subsurface to Atmosphere}}$	tCO_2	N/A	N/A	N/A	Quantity being calculated.
	Mass of CO_2 leaked from the Subsurface to Atmosphere/ Mass $CO_{2\ \text{leaked}}$	tCO_2	Estimated	If a leak event occurs, the mass of CO_2 leaked from the subsurface to the atmosphere shall be estimated with a maximum overall uncertainty over the reporting period of ±7.5% In case overall uncertainty of the applied quantification approach exceeds ±7.5%, an adjustment shall be applied Refer to Appendix B for further guidance	N/A	Estimation would be required for reporting to the Alberta Energy Regulatory authority Direct measurement is likely not possible, but the use of engineering estimates and accounting for the uncertainty would be a reasonable approach in the event leakage occurs
P25 Loss, Disposal, or Recycling of Materials Used in CO_2 Capture Processes	**$\text{Emissions}_{\text{Loss, Disposal or Recycling of Material Used in CO2 Capture Process}} = \sum (\text{Vol. Used}_i * \text{EF Used}_{i\ CO2, CH4, N2O}) * \text{GWP}_{CH4, N2O}$**					
	$\text{Emissions}_{\text{Loss, Disposal or Recycling of Material Used in CO2 Capture Process}}$	tCO_2e	N/A	N/A	N/A	Quantity being calculated in aggregate based on quantity of materials used for the emission offset project
	Total Volume of Material Lost, Disposed or Recycled from the CO_2 Capture Process/Vol. Used $_i$	L/ m^3/ Other	Estimated	Estimation of the volume of material inputs lost, disposed or recycled for the CO_2 capture process Must be estimated for material streams of 500 tonnes or greater of CO_2e annually	Engineering report will specify the volume of material input lost, disposed or recycled for an appropriately sized	Represents most reasonable means of estimation. Loss, disposal or recycling estimates for the emission factors for the materials used

Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
					Carbon Capture Facility	
	Emissions factor for each type of material input / EF Used $_{i\ CO2,\ CH4,\ N2O}$	tCO_2e per L / m^3 / other	Estimated	Emission offset project specific design	Annual	Production and delivery estimates for the emission factors for the material inputs
	GWP $_{CH4,\ N2O}$ Global Warming Potential	Unitless	Estimated	Per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	As published
P26 Flare at Injection, Production Wells and Recycle Stream	$Emissions_{\text{Flaring and Incineration}} = (Vol._{\text{Gas Flaring}} * EF\ CO_2) + (Vol._{\text{Gas Flaring}} * \%\ CH_4 * \rho_{CH4} * (1 - DE) * GWP_{CH4}) + (Vol._{\text{Gas Flaring}} * EF\ N_2O * GWP_{N2O}) + (Vol._{\text{Supplemental Gas}} * EF\ CO_2) + (Vol._{\text{Supplemental Gas}} * \%\ CH_4 * \rho_{CH4} * (1 - DE) * GWP_{CH4}) + (Vol._{\text{Supplemental Gas}} * EF\ N_2O * GWP_{N2O})$					
	Emissions $_{flare}$	tCO_2e	N/A	N/A	N/A	Calculation of emissions from project flare, incinerator or combustor
	Volume of Gas sent to Flare or Incinerator / Vol. $_{\text{Gas Flaring}}$	e^3m^3	Measured	Online metering of volume of 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 Alberta Greenhouse Gas Quantification Methodologies
	Volume of Supplemental Gas to operate flare or incineration equipment at STP[2]. Pilot purge and/or supplemental fuel / Vol. $_{\text{Supplemental Gas}}$	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 Alberta Greenhouse Gas Quantification Methodology
	Emission Factor for CO_2 / EF_{CO2}	tCO_2/ e^3m^3	Estimated	Site specific, calculated based on gas analysis using the procedures in Appendix C, Section C.1. of the Alberta Quantification Methodology Alternatively, if this is not available, use the default value for rich gas for the appropriate device type (unassisted	Annual	Direct measurement will be the most accurate See Flaring Chapter of the Alberta Greenhouse Gas Quantification Methodology

[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
				flare, assisted flare or incinerator) from the Flaring Chapter of the Alberta Greenhouse Gas Quantification Methodology		
	Methane Composition of Flared Gas / % CH_4	%	Measured	Direct Measurement as outlined in Directive 017. Measurement of the concentration must be representative of the gas stream sent to flare. Alternatively, if this is not available, use the default value for rich gas from the Alberta Greenhouse Gas Quantification Methodology	Annual	Direct measurement is the most accurate using weighted average gas composition See Flaring Chapter of the Alberta Greenhouse Gas Quantification Methodology
	Density of CH_4 / $_{\rho CH4}$	t/e^3m^3	Constant	0.6785 kg/m3 at STP	N/A	Accepted value as per Alberta Greenhouse Gas Quantification Methodology
	Destruction Efficiency of Flare or Incinerator / DE	%	Estimated	Field measured destruction efficiency OR, if this is not available, use manufacturer’s specifications OR, if neither is available, use default methane destruction efficiency for unassisted flares in the Alberta Greenhouse Gas Quantification Methodology are conservative	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
	Emission Factor for N_2O / EF_{N2O}	tN_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	See Flaring Chapter of the Alberta Quantification Methodology (note this does not vary by flare/incinerator device type)
	Global Warming Potential / $GWP_{CH4, N2O}$	Unitless	Estimated	Per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	As publlished

5. Data Management

All emission offset projects must be supported with sufficient high quality data, and/or methods to fulfill the quantification requirements listed in this protocol, and be substantiated by records for the purpose of independent verification to a reasonable level of assurance. The Regulation requires that data must be quantifiable, measurable directly or by accurate estimation using replicable techniques. A third party assurance provider is responsible for evaluating the project and any claims and must reach the same conclusions using evidence-supported data.

In support of meeting project data requirements, data must be managed in a manner that substantiates:

- emissions and reductions that have been recorded pertain to the offset project activity;
- all emissions sources that should have been recorded were recorded accurately and appropriately;
- emissions and reductions quantification has been recorded transparently and appropriately;
- emissions and reductions have been recorded in the correct reporting period;
- emissions and reductions have been recorded in the appropriate category; and
- emission offset projects must have an auditable data management system.

The emission offset project developer must establish and apply quality management procedures to manage data and information. Written procedures must be established for each measurement task outlining responsibility, timing and location requirements. Verification requirements are outlined in the Standard for Validation, Verification and Audit.

5.1. Project Monitoring

Monitoring requirements for CO_2-EOR enhanced oil recovery projects are addressed in two distinct categories: measurement for emission offset quantification purposes; and the monitoring activities that provide operational containment assurance. The first includes measurement activities required to quantify the net geological sequestration of CO_2 from the CO_2 capture, transportation and enhanced oil recovery injection activities that are outlined in this protocol.

The second category pertains to monitoring activities to ensure that the CO_2 injected into CO_2 EOR storage schemes is permanently contained within the project/storage complex. Each EOR project must comply with the relevant Directives and Regulations and any specific monitoring requirements included in the EOR scheme approval issued by the AER.

Approvals to operate a CO_2 EOR storage scheme are managed by the AER under section 39 of the *Oil and Gas Conservation Act*.

5.1.1. Project Monitoring Requirements for Quantification

Monitoring requirements include measurement of all relevant parameters to account for all supplemental energy inputs (e.g., fossil fuels, heat and electricity) required for the operations of the CO_2-EOR storage project.

The projects' measurement devices should be off-the-shelf metering equipment such as gas or fluid flow meters, utility meters (gas and electricity) and gas analyzers. Any assumptions and contingency procedures must be documented. Meters must be maintained to ensure consistent operation with design specifications and must be calibrated according to AER requirements and quantification methodology requirements, otherwise according to manufacturer's specifications. Reference AER Directive 017 Measurement Requirements for Oil and Gas Operations for guidance on calibration frequency for chain of custody meters. It is assumed that CO_2 chain of custody meters to have the same annual calibration requirements as natural gas chain of custody meters.

5.1.2. Project Monitoring Plan for Quantification

A monitoring plan must be established for all monitoring and measurement activities associated with the project. This monitoring plan will serve as a basis for third party assurance providers to confirm that the monitoring and measurement requirements have been met, and that consistent, rigorous monitoring and record keeping of measurement is ongoing at the emission offset project site. The monitoring plan must cover all aspects of monitoring and measurement for quantification of emissions contained in this protocol and must specify how data for all relevant parameters listed in Table 6 will be measured, collected and recorded. The monitoring plan is submitted as part of the offset project plan and must be available during any verification or reverification processes.

At a minimum the monitoring plan shall stipulate and include:

- The frequency of data acquisition;
- A record keeping plan;
- Identification of key instrumentation;
- Validation activities to prove the accuracy of gas composition measurements (see section 5)
- The frequency of instrument calibration activities;
- The QA/QC provisions on data acquisition, management and record keeping that ensure monitoring, and the use and storage of data, is carried out consistently and with precision;
- The role of individuals performing each specific monitoring activity;
- Methods to measure and quantify the following data:
    - Energy inputs required to capture, dehydrate, compress, transport, inject and store CO_2 including:
        - Direct fuel inputs; and
        - Indirect energy inputs or other parasitic loads (e.g., heat or electricity consumption);
- Quantity and concentration of CO_2 sold to third parties including sufficient measurements to support data required;
    - Quantity and concentration of CO_2 injected into the EOR storage scheme;
    - Evidence that produced CO_2 is fully re-injected or otherwise accounted for; and
    - Regular leak detection and repair (LDAR Surveys) to quantify fitting, piping and equipment leaks.

Although some of the above data may not be required for the quantification of emissions, emission reductions, and geological sequestration, they must be tracked and reported for completeness purposes.

Additional measurements may be made to support quantification. At each of the measurement points, the mass of the gas stream must be determined based on the volumetric or mass flow, and composition of the gas stream.

Section 5.1.5 and 5.1.6 provide guidance on the measurement and monitoring requirements. It is also necessary to monitor the incremental energy inputs (fossil fuels and electricity) required to operate the enhanced oil recovery project. The general monitoring requirements for fossil fuel and electricity inputs are listed in 5.1.6.

5.1.3. Balancing Confirmation for Physical Systems

Projects (TIER or otherwise) need to total to the physical system (reported on annually) other than emissions which may be double counted. Balancing confirmation must be carried out for the following quantities:

Total CO2 entering the system

Total injected CO2

Total emissions must be greater or equal to total physical system emissions

Total electricity imported/exported

Total heat imported/exported

Prorating should be done on CO2 shares (ratios of CO2 supplied by each project) unless mutually agreed upon by all impacted projects (TIER or non-TIER such as voluntary market projects).

Reporting for the physical system, where it is not represented by a single offset project, should be verified annually based on calendar year and will be posted alongside documents for each offset project which it supports in that year. If there are confidentiality concerns associated with physical system reporting documents, please contact the Director, Emission Offsets for alternative handling of physical systems reporting.

Physical system reporting should be done based on calendar year. Projects are permitted to report on a part year for their first year of operations but must align their reporting with the calendar year following the first part year. Projects can report for an entire calendar year, or subdivisions of a calendar year.

Emission offset projects can report on a more frequent basis as long as true-up to annual physical totals occurs. Where a physical system is fully represented by a single offset project no separate reporting for the physical system is required.

5.1.4. Gas Stream Flow Rate and Measurement Requirements

Meter readings must be corrected for temperature and pressure using standard temperature and pressure as defined in the Alberta Quantification Methodologies. Estimates of CO_2 concentration and density are not acceptable.

Flow meters must be placed based on manufacturer recommendations and be located at the input to the transport equipment such that they are downstream of all capture and compression equipment to account for any fugitive losses or venting; and be as close as possible to the injection wellheads to ensure accurate measurement of the injected volumes.

Flow meters should not include re-injected fluid and must be calibrated according to manufacturer specifications and AER requirements.

Meters must be checked/calibrated at regular intervals according to these specifications and industry standards.

When orifice meters are used, since pressure drop is measured and flow rate is calculated within the control logic, the density of the injection gas must be measured as per Table 6, using a third-party gas analysis. The measured density must be revised and entered into the control logic semi-annually.

Chain of custody CO_2 flow meters must be calibrated/validated in accordance with AER Directive 17 under the same calibration schedule as is advised for natural gas chain of custody meters, and

Ownership transfer must be clearly documented for CO_2 transferred (third party injection activity).

It is also necessary to monitor the incremental energy inputs (fossil fuels, heat and electricity) required to operate the carbon capture, transport, injection, and re-injection facilities.

Concentration of Gas Stream

The gas composition shall be metered downstream of the capture and processing equipment or upstream of the injection field at a custody transfer point, while the volume is measured as close as possible to the point where CO_2 is injected into the targeted CO_2 storage zone(s).

The project must validate the accuracy of selected analyzers. Validation may include a combination of laboratory analysis of samples, performance specification tests from the Alberta Continuous Emission Monitoring System (CEMS) Code, and/or statistical analysis. Validation frequency may be managed adaptively. Frequency should be high to start, may be decreased upon consistent validation and subsequently increased upon inconsistent validation.

5.1.5. Measurement and Monitoring Guidance for Energy Inputs

Volume of Fossil Fuels Combusted

Gaseous fossil fuels must use a continuous measurement of the gas flow rate. In the event that gas flow rate is metered by a utility provider and continuous measurement is not accessible, projects may use monthly billing accounting or periodic readings to reconcile gas consumption.

Flow meter readings must be corrected for temperature and pressure using standard conditions as defined in the Alberta Quantification Methodologies. Density estimates used for emission quantification must also reflect these standardized conditions, and all instruments must apply consistent reference parameters.
Flow meters shall be placed based on manufacturer recommendations and shall operate within manufacturers specified operating conditions at all times. Flow meters must be calibrated according to

manufacturer specifications and shall be checked and calibrated at regular intervals according to these specifications.

Liquid fossil fuels must conduct reconciliation of purchasing records on a quarterly basis and inventory adjustments as needed. Volume or mass measurements are made at purchase or delivery of the fuel. Reconciliation of purchase receipts or weigh scale tickets is an acceptable means to determine the volumes of fossil fuels consumed to operate the carbon capture and storage project.

Electricity Consumption

For electricity consumption continuous measurement of electricity consumption is required, or reconciliation of maximum power rating for each type of equipment and operating hours. In the event that electricity consumption is metered by a utility provider and continuous measurement is not accessible, projects may use monthly billing accounting or periodic readings to reconcile electricity consumption.

Electricity consumption must be from continuously metered data wherever possible; however, in certain cases other loads may be tied into the same electricity meter. Where this occurs, estimates with justification are required. In these cases, the maximum power rating of each piece of equipment is used in conjunction with a conservative estimate of operating hours to estimate the electricity consumption; and electricity meters must be calibrated by an accredited third party in accordance with manufacturer specifications.

5.1.6. Monitoring and Reservoir Management Plan for Containment Assurance

Monitoring requirements, based on the characteristics of the reservoir and EOR scheme, are outlined by the AER in the CO_2-EOR storage scheme approval. It requires each EOR scheme to undertake specific monitoring and reservoir management activities to ensure the safe and permanent storage of CO_2. Risk factors for each project may be considered by the AER when determining the conditions of the scheme approval. General risk factors include financial failure, technical failure, management failure, regulatory and social instability, and natural disturbances. The following AER Directives outline specific conditions for measurement and monitoring:

- **Directives 007 and 017**: requirements for measuring and reporting the amounts of CO_2 injected;
- **Directive 020**: minimum requirements for well abandonment, testing to detect leakage and mitigation measures in the event of detecting leakage;
- **Directive 051**: requirements for injection and disposal wells, including the wellbore design, wellbore integrity logging, operational monitoring, and reporting requirements;
- **Directive 60**: requirements for flaring, incinerating, and venting in Alberta at all upstream petroleum industry wells and facilities.
- **Directive 065**: application requirements for an Enhanced Recovery Scheme (such as CO_2-EOR) and a disposal scheme (such as CO_2 Disposal and Containment); and

As required in the EOR scheme approval by AER, the annual progress report will provide containment assurance specific to the targeted geologic storage zone(s). The third party assurance provider must have access to the annual progress report submitted to the AER to ensure no CO_2 has escaped from any wellbores penetrating the project reservoir, and no CO_2 migrated from the subsurface to the atmosphere or out of the targeted geologic storage zone(s), or if it has, that it has been fully accounted for.

Hence, the overall objective of the monitoring plan is reservoir management for CO_2 containment assurance.

Where operational containment assurance is required by the AER, the EOR operator shall also provide to the Director, a subset of the submitted data in the form of a Containment Assurance Report (See Containment Assurance Report Template in Appendix D). It is based on measurement and engineering data that encompasses such items as; the results of reservoir management practices, including quantity and concentration of the injected, produced and re-injected CO_2. Additionally, any CO_2 moved outside of the EOR Scheme approval area must be reported in the Containment Assurance Report. Operational containment assurance may include results from other monitoring undertakings if other parameters are available from the EOR operator.

Containment assurance and reservoir management shall be reviewed periodically by the EOR operator, and the EOR operator must provide immediate notice to the Director, and take corrective action if changes occur that have the potential to adversely affect containment, which may include:

- Unexpected changes in project performance that influence associated storage of CO_2;
- Addition or abandonment of injection zones;
- Addition or abandonment of injector or producer wells;
- Anomalous change of injection-withdrawal ratio;
- Development of reservoirs which are located above or below the project reservoir;
- Discovery of CO_2 beyond the boundary of the CO_2-EOR storage complex; or
- Removal or release of CO_2.

The CO_2 EOR Storage Scheme approval issued in accordance with AER Directive 065 requires the project operator to develop a termination plan that outlines criteria for ending the CO_2 EOR project. This termination plan shall be developed any time after CO_2 injection begins but must be developed prior to the termination of CO_2 injection at the scheme. The plan should specify:

- The termination process and anticipated timing;
- Plans for moving CO_2 from the storage complex;
- Monitoring consistent with AER requirements for CO_2 -EOR scheme closure;
- Corrective measures to address potential leakage; and
- Provisional plans for site decommissioning, including plans for plugging and abandonment of wells and decommissioning of facilities.

Upon request, the emission offset project developer must demonstrate that a reservoir management plan for containment assurance is in accordance with any and all applicable AER, Alberta Environment and Protected Areas, and Alberta Energy requirements. The emission offset project developer must also confirm that the project continues to operate in accordance with the conditions outlined in the operating license. These results could be used to provide evidence of containment, including the supporting rationale.

5.1.7. Missing Data Procedures

If an emission offset project developer discovers that there is missing data, the procedures for estimating missing data set out in section 17.5.2 of the Alberta Quantification Procedures (AQM) must be followed with consideration for conservativeness to determine an appropriate substitute for missing data required under the protocol. The project developer must identify the missing data procedure that will be followed in the offset project report and be part of the verification for professional review for reasonableness and conservativeness.

5.2. Required Project Documentation

Documentation requirements for all Alberta emission offset projects applying this protocol are, including but not limited to:

- The CO_2 -EOR storage scheme number;
- Evidence of the CO_2 injection start date;
- Energy use records for capture, transport and CO_2 -EOR scheme operations;
- Concentration and measurement records of injected, produced and reinjected CO_2;
- A completed Report Balance Sheet for CO_2 from Appendix C that includes:
  - The gross quantity of new CO_2 injected into the scheme, not including re-injected CO_2;
  - The project emissions for the current reporting period;
  - The quantity of previously injected CO_2 transferred to or from a Type 2 EOR Scheme (and associated transfers of Holdback amounts, as applicable);
  - The quantity of previously injected CO_2 moved from a Type 1 EOR Scheme (and forfeit of Holdback amounts, if applicable);
  - The net quantity in tonnes, of CO_2 stored by the project (CO_2 in place); and
  - The net Holdback quantity for the reporting period and the cumulative quantity.
- A completed Reservoir Pressures Table (Table 7 below) submitted to Director for approval to register a project.
  - A suitable reservoir management plan as defined by AER requirements;

- Evidence that each project results in net geological sequestration located in Alberta including legal land location or GPS coordinates of the site via the inventory.

Table 7: Reservoir Pressure Table

Summary of CO_2-EOR Storage Scheme Approval Values for the Emission Offset Project

Item	Reservoir Pressure Name	Type 1 Scheme Approval (kPa)	Type 2 Scheme Approval (kPa)	Comments/Data Source is CO_2-EOR- Storage Scheme Approval
a.	Initial reservoir pressure (Pi)	______	______	CO_2-EOR Scheme Approval
b.	Reservoir pressure prior to start of the CO_2-EOR scheme (Pprior)	______	______	CO_2-EOR Scheme Approval or Application
c.	Minimum Miscibility Pressure (MMP)	______	______	for CO_2 in oil CO_2-EOR Scheme Approval
d.	Minimum reservoir injection pressure (Pinj)	______	______	No production allowed if pressure drops below this value
e.	Maximum injection pressure (Pmax)	______	______	No production allowed if pressure increases above this value
f.	Maximum reservoir pressure at cessation of oil production under the approved CO_2-EOR scheme (Pend)	______	______	CO_2-EOR Scheme Approval
g.	Required reservoir pressure at abandonment (Pabandon)	______	______	CO_2-EOR Scheme Approval may say equal to or below

5.3. Record Keeping and Project Archives

The department requires that emission offset project developers retain records as per the requirements of the Regulation. Where the emission offset project developer is different from the person implementing the activity, or part of the activity, as in the case of an aggregated emission offset project, the individual projects and the aggregator must both maintain sufficient records to support the offset project. If project ownership changes, sufficient records to support the offset project must be provided to the new owner. The following records must be collected and disclosed to a third party assurance provider upon request.

Record keeping requirements include but not limited to:

- Raw baseline period data, independent variable data, and static factors within the measurement boundary;
- A record of all adjustments made to raw baseline data with justification;
- All analysis of baseline data used to create mathematical model(s);
- All data and analysis used to support estimates and factors used for quantification;
- Metering equipment specifications (model number, serial number, manufacturer's calibration procedures/field meter proving method);
- A record of changes in static factors along with all calculations for non-routine adjustments;
- All calculations of greenhouse gas emissions/reductions and emission factors;
- Measurement equipment maintenance activity logs;
- Measurement equipment calibration records or field meter proving records. Flow meters should be maintained and calibrated according to manufacturer specifications and in accordance with the more

stringent of the AER requirements and the Quantification Methodologies under Alberta greenhouse gas regulations, and the Specified Gas Reporting Regulation (which requires a calibration frequency of once every 3 years); and

- For meters that cannot be calibrated or proven 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.

5.4. Quality Assurance/Quality Control Considerations

Quality Assurance/Quality Control are applied to add confidence that all measurements and calculations have been made correctly. These 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 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 changes to operational procedures continue to function as planned and achieve net geological sequestration;
- 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

Alberta Energy Regulator (AER). Directive 7 Volumetric and Infrastructure Requirements, September 2011. Directive 17 Measurement Requirements for Oil and Gas Operations, December 2018. Directive 20 Well Abandonment, December 2018. Directive 51 Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements, March 1994. Directive 65 Resources Applications for Oil and Gas Reservoirs, April 2014

American Petroleum Institute (API). International Petroleum Industry Environmental Conservation Association (IPIECA). Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects. Part II: Carbon Capture and Geological Storage Emission Reduction Family, June 2007

American Petroleum Institute (API). Compendium of Greenhouse Gas Emissions for the Oil and Gas Industry, August 2009

Canadian Standards Association (CSA). Z741 Geological Storage of Carbon Dioxide, December 2012

Det Norske Veritas (DNV). CO_2QUALSTORE Guidelines for Selection and Qualification of Site and Projects for Geological Storage of CO_2, February 2010

Government of Alberta. Carbon Offset Emission Factors Handbook

Government of Alberta. Technical Guidance for the Assessment of Additionality

Government of Alberta. Standard for Greenhouse Gas Emission Offsets Project Developers

Environmental Protection Agency (EPA). Proposed Rule Subpart RR–Carbon Dioxide Injection and Geologic Sequestration, March 2010

IPCC, 2014: Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)]. IPCC, Geneva, Switzerland, 151 pp.

International Energy Agency. Monitoring and Reporting Guidelines for Injection and Storage

International Organization for Standardization. ISO 14064-2:2019 Specification with Guidance at the Project Level for Quantification, Monitoring and Reporting of GHG Emission Reductions and Removal Enhancements

International Organization for Standardization. ISO 27915:2017 Carbon dioxide capture, transportation and geological storage - Quantification and verification, 2017

International Organization for Standardization. ISO 27916:2019 Carbon dioxide capture, transportation and geological storage — Carbon dioxide storage using enhanced oil recovery (CO_2-EOR)

University of Alberta Kostiuk, Larry. Johnson, Matthew, and Thomas, Glen. Flare Research Project, Final Report. University of Alberta, September 2004

World Resources Institute (WRI). Guidelines for Carbon Dioxide Capture, Transport, and Storage, October 2008

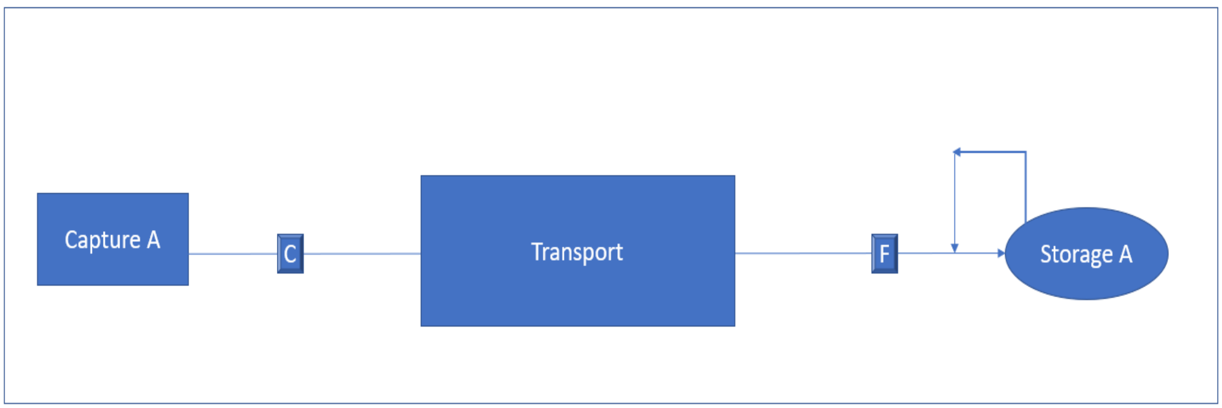
APPENDIX A: CO_2 Injection by Multiple Developers

Guidance for the Injection of CO_2 by Multiple Networks

The following provides guidance for projects in which CO_2 is being transported for use in CO_2-EOR storage schemes.

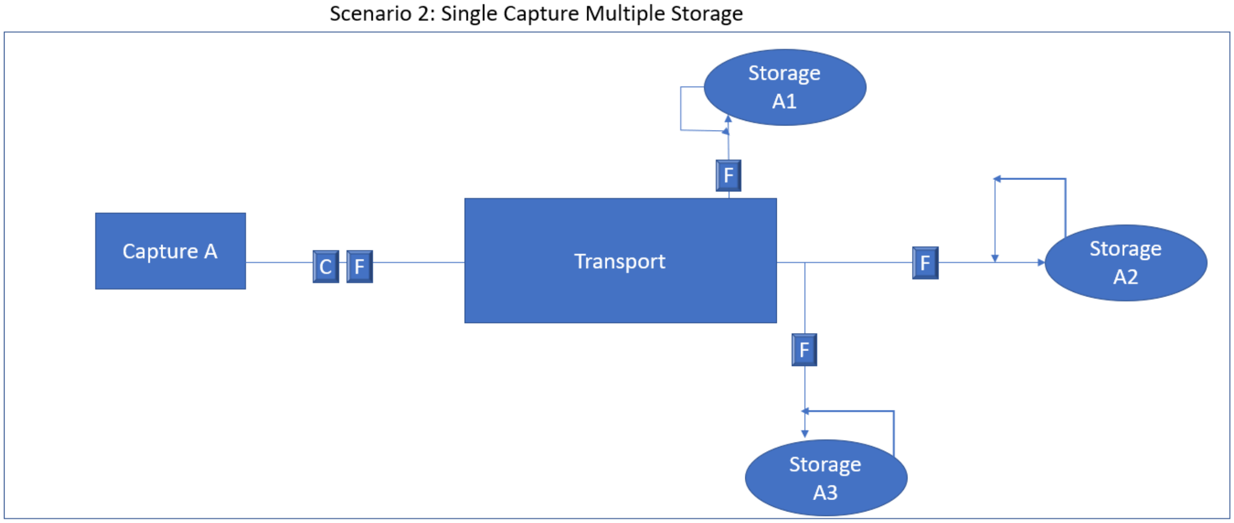
Gas flow/quantity measurement and CO_2 concentration measurement/sample points must be carefully considered in complex/multiple networks. Scenarios 1 through 4 depict the fluid flow measurement and CO_2 concentration measurement/sample points in a variety of project configurations from simple to more complex.

Scenario 1: Single Capture Single Storage



Must measure CO_2 concentration or gas composition (C). The sample point may be downstream of capture or at the storage location (injection well) upstream of the location where the produced gas stream is reinjected. Must measure gas quantity (F) at storage location (injection well) upstream of the location where the produced gas stream is re-injected.

Scenario 2: Single Capture Multiple Storage

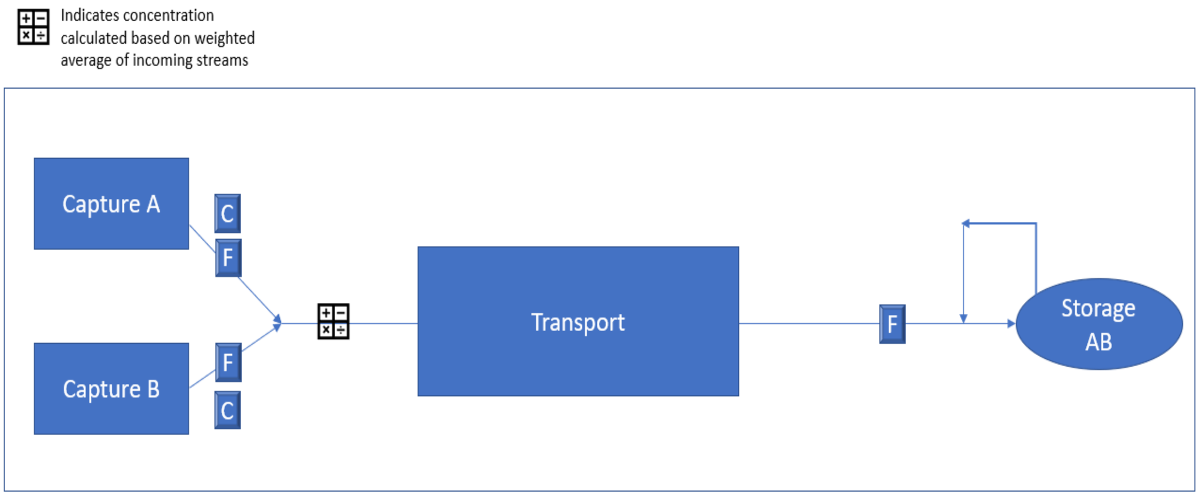


Must measure CO_2 concentration or gas composition (C) at either at the point of capture or points of storage. Not required to measure both locations. Must be measured upstream of the location where the recycle stream is reinjected.

Must measure gas quantity (F) at the point of storage upstream of the produced gas re-injection. Not required to measure gas quantity at inlet of Transport unless gas quantity at each storage location is not available. Must have n-1 measured gas quantities in all cases.

Measured CO_2 concentration at the inlet to transport will be equal to the CO_2 concentration at storage.

Scenario 3 - Multiple Capture Single Storage



Must measure CO_2 concentration or gas composition at each capture sites upstream of comingling.

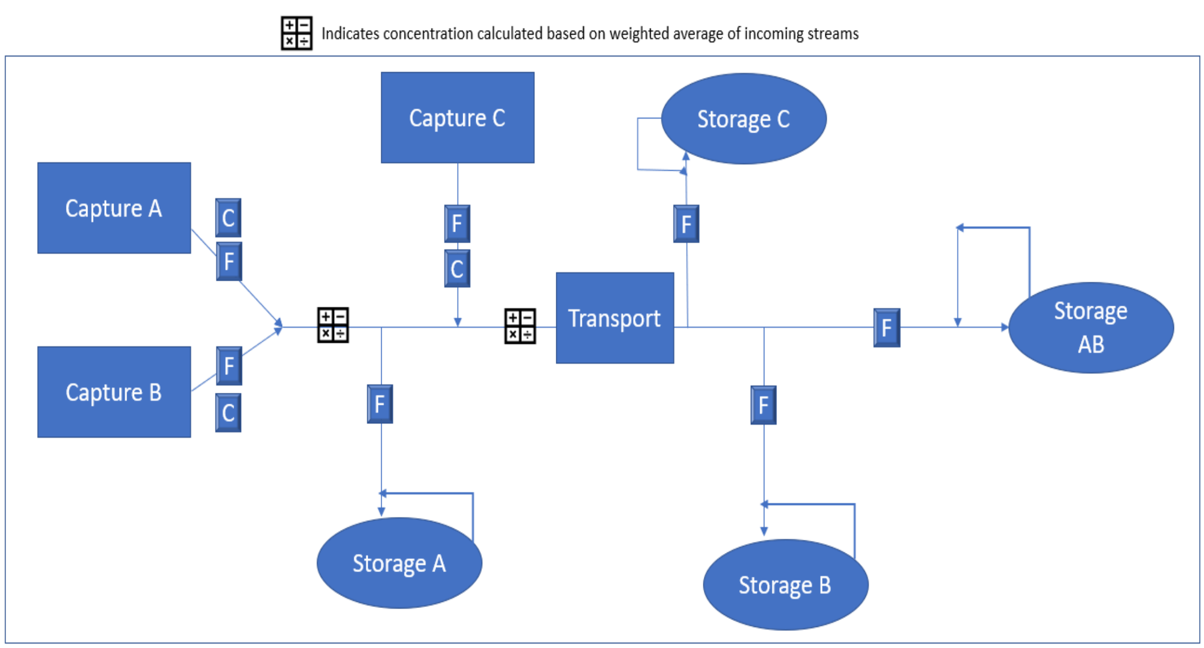
Must measure gas quantity at each capture site upstream of comingling.

Allowable to calculate the CO_2 concentration of the comingled stream based on the weighted average of the incoming streams to be comingled in a single variable, mass balance equation.

Must measure gas quantity at storage upstream of produced gas re-injection. The CO_2 concentration at storage is the calculated concentration of the comingled stream.

If using a weighted average method, it must be completed downstream of each new capture site that is added to the network.

Scenario 4 - Multiple Capture Multiple Storage Scenario



Must measure CO_2 concentration or gas composition at each capture site upstream of comingling.
Must measure gas quantity at each capture site upstream of comingling.

Allowable to calculate the CO_2 concentration of the comingled stream based on the weighted average of the incoming streams to be comingled in a single variable, mass balance equation.

Weighted average calculation must be completed downstream of each new capture site that is added.

Measure gas quantity at storage upstream of re-injection. CO_2 concentration at injection is the calculated concentration of the comingled stream or measured upstream of injection. When there is a single unknown, the concentration must be measured at each capture site upstream of where the capture stream comingles.
In addition to careful consideration to sample points and measurement, in complex networks, emission offset project developers must demonstrate that all SSs are properly accounted for and must ensure all emissions have been included and have not been double counted. For a complex CO_2 system or network, the emissions from that network must be included in the project condition using a system emission factor or a proration of emissions across the network. The emission offset project developers must provide verifiable justification for the method and values used to determine the system emission factor used.

In the multiple capture multiple storage scenarios, details of a full system wide allocation of emissions for each project must be provided for verification/reverification. To protect commercially sensitive information, each emission offset project developer will receive a report with the relevant details (mass flow, CO_2 concentration and allocated carbon emissions for the pipeline system) for their specific project as required for verification in compliance with Standard for Validation, Verification and Audit. The remainder of the system measured data may be presented to the emission offset project developer as one unspecified group rather than delineated by each of the other companies within the system.

Project Emissions Prior to Tie-in Point

Project emissions prior to the tie-in point are described as any emission occurring before the pipeline splits to deliver the CO_2 to the multiple developers. Project emissions prior to the tie-in point are characterized by all the emissions associated with capturing CO_2.

To properly account for all project emissions, emission offset project developers must proportionally allocate all project emissions prior to the tie-in point across all developers. Each developer must account for their allocation of project emissions. This results in an equal distribution of the associated project emissions prior to the tie-in point depending on the quantity of CO_2 injected by each developer.

For example, if Developer A injects 60% of the captured CO_2 and Developer B injects the other 40%, the upstream project emissions associated with the captured CO_2 are allocated proportionally to each developer. In this example, Developer A is allocated 60% of the total project emissions prior to the tie in point. Developer B is allocated 40% of the total project emissions prior to the tie in point.

Project Emissions Subsequent to Tie-In Point

Project emissions subsequent to the tie in point are described as any emission occurring after the pipeline splits to deliver the CO_2 to the multiple developers. Each developer must account for individual project emissions associated with CO_2 injection.

Requirements for Complex CO_2 Networks

- Capture facility operators will measure the CO_2 concentration and quantity of gas at the capture site and will measure all data points as required to determine the emissions of the capture operation.
- Transport (pipeline operator) will maintain an auditable and verifiable custody transfer system tracking mass of CO_2 accepted onto the pipeline and delivered to each major off taker.
- Transport (pipeline operator) will measure all data points required to quantify the emissions related to transport operations.
- Storage (CO_2-EOR) operators will measure all data points required to quantify the emissions of the CO_2-EOR operations.

APPENDIX B: Guidance for Estimating Emissions from Subsurface Equipment and Targeted Geologic Zone(s)

For the quantification of P22 - Emission from Subsurface to Atmosphere, the quantity of emissions leaked from the subsurface equipment or EOR Subsurface operations to atmosphere for each of the leakage events must be estimated with a maximum overall uncertainty of ±7.5% over the reporting period. If the amount of emissions leaked can be estimated within an uncertainty range of ±7.5%, the estimated figure is reported and used. If the overall uncertainty exceeds ±7.5%, the following adjustment must be used:

CO_2, Reported [tonnes CO_2] = CO_2, Quantified [t CO_2] * (1 + (Uncertainty System [%]/100))

Where:

CO_2, Reported: Amount of CO_2 to be included into the annual emission report with regards to the leakage event in question;

CO_2, Quantified: Amount of CO_2 determined through the used quantification approach for the leakage event in question; and

Uncertainty System: The level of uncertainty which is associated to the quantification approach used for the leakage event in question.

Adapted from sources:

1) The International Energy Agency presentation, on ‘Monitoring and Reporting Guidelines for Injection and Storage’, January 2014, states “Maximum ±7.5% uncertainty, if exceeded then add ‘uncertainty Adjustment’”. Implications of the Inclusion of Geological Carbon Dioxide Capture and Storage as CDM Project Activities, https://cdm.unfccc.int/EB/050/eb50annagan1.pdf
2) The Proposed Agenda – Annotations pp 44, Clean Development Mechanism of the United Nations Framework Convention on Climte Change, 2009 states: It is important to be conservative and so err on the side of overestimation rather than underestimation. An example of how to apply this conservative principle is provided by the EU ETS Monitoring and Reporting Guidelines for CCS63. In these, if the uncertainty is above a specified level for the measured emissions of seepage, these measured emissions will be multiplied by an “uncertainty supplement”. In the EU case this is set for a maximum uncertainty of 7.5%, and if this cannot be achieved then measured emissions are multiplied by an uncertainty supplement (which is added to the measured emissions).

APPENDIX C: Report Balance Sheet for CO_2

A completed balance sheet must be included with every verified emission offset project report and the final report for requesting release of holdback.

CO_2-EOR Emission Offset Project Name:
CO_2-EOR Emission Offset Project Identifier:
Reporting Period Start:
Reporting Period End:

CO_2 Inventory	**Prior Cumulative (tonnes CO_2)**	**This Reporting Period (tonnes CO_2)**	**New Cumulative (tonnes CO_2)**
CO_2 In Place, resulting from the emission offset project		(place period delta here)	
Newly Captured CO_2 Injected Quantity			
CO_2 Transfers from this project for Type 2 only Transferred to:			
Associated Holdback transfer from this Type 2 project, if applicable Transferred to:			
CO_2 Transfers to this project Transferred from:			
Associated Holdback transfer to this project, if applicable Transferred from:			
Project Emissions			
Reversals Post Project			
Non-Removal Emission Offsets (tonnes CO_2e)			
Removal Emission Offsets (if applicable) (tonnes CO_2e)			
Uncredited Volume (either prior to or post project)			
Holdback Amount (Hf in tonnes CO_2e)			
Holdback Balance (total holdback less transfers out plus transfers in)		(place period delta here)	
Discounted baseline emissions (Df in tonnes CO_2e)			

APPENDIX D: Containment Assurance Report Template

A completed **Containment Assurance Report** is required to be submitted by the emission offset project developer to the Director each calendar year, including each year in the post crediting period (it is not required to be part of project report submitted to the Registry). The time period should match the Annual Progress Report submitted to the AER. The AER may also flag any non-compliance events to the Regualator.

Alberta regulation sets out that the geological sequestration of carbon dioxide must be permanent. The purpose of this Containment Assurance Report is to demonstrate that sequestration from an Enhanced Oil Recovery scheme (and emission offset project) is permanent during the offset crediting period and for the necessary period after the offset crediting period. This report will identify an event that resulted in non-permanent sequestration (i.e. reversal) of the CO_2.

Events that could potentially result in non-permanent sequestration of the CO_2 include:

1) Migration of CO_2 beyond the permitted geology;
2) Mechanical integrity/well failure/integrity of existing wells in the field;
3) Production of CO_2 to surface and venting to atmosphere;
4) Production of CO_2 to surface and diversion to flare;
5) Fugitive emissions of CO_2; and,
6) Production of CO_2 and transfer out of the scheme approval area.

<u>Containment Assurance Report - Alberta Emission Offset System</u>

1.0 Project Identification
Reporting on Calendar Year:

Emission Offset Project Name:

Project ID:

Emission Offset Project Developer:
Prepared by:
Submission Date:

1.1 EOR Storage Scheme Approval Number:

1.2 Project Type (Type 1 or Type 2):

2.0 Assurance of Containment:

2.1 Mass of CO_2 Injected:

Provide evidence of total new CO2 injected over the last calendar year, including a table with the monthly compositions, volumes, the weighted average composition and quantity injected.

Provide evidence of the net tonnes of CO_2 injected over the last calendar year.

Describe how any recycled CO_2 is measured and accounted for in the net CO_2 injected over the last calendar year.

Indicate Directives and data sources from which this evidence is provided.

<u>2.2 Conclusion</u>
The total injected CO_2 for the the calendar year is ________ tonnes.

2.3 Migration of Subsurface CO_2

Describe the Permitted Geologic Boundaries and the CO2 Plume Extent.
Indicate Directives and data sources from which this evidence is provided (for example, Directive 065, Petrinex).

Conclusion

Explain whether the CO_2 plume is extending beyond the permitted geology, and if it is, provide a quantification of CO_2 volumes that extend outside the permits.

2.4 Reporting of CO_2 Vented, Flared, and Fugitive Emissions

Provide a summary of the emission offset project developer's approach to inventorying, quantifying and reporting vented, flared and fugitive emissions. Include a description of any tracking software used and calculation methods used to to quantify emissions.

2.4.1 Reporting of CO_2 Vented

Provide evidence of any CO_2 vented in the calendar year.
Indicate Directives and data sources from which this evidence is provided.

Conclusion

The total quantity of CO_2 vented during the calendar year from the _____ Project is _____tonnes.

2.4.2 Reporting of CO_2 Flared

Provide evidence of all CO_2 flared and all supplemental fuel flared during the calendar year in units of tonnes CO_2e.
Indicate Directives and data sources from which this evidence is provided.

Conclusion

The total quantity of CO_2 flared during the calendar year was ______ tonnes CO_2e.
The total quantity of supplemental fuel flared during the calendar year was ______ tonnes CO_2e.

2.4.3 Reporting of Fugitive Emissions of CO_2

Provide evidence of any CO_2 from fugitive emissions in the calendar year in units of tonnes CO_2e.
Indicate Directives and data sources from which this evidence is provided.

Conclusion

The total fugitive emissions of CO_2 during the calendar year is ____ tonnes CO_2e.

2.5 Reporting of CO2 Transferred outside of scheme area

Provide the individual quantities of CO_2 transfered out of the approved EOR Scheme Area (permitted geology) during the calendar year, and where the CO_2 was transferred to (ie., a specific EOR scheme/offset project, another facility, etc.).

Provide the total quantity of CO_2 transferred.

Conclusion

There has been an individual transfer of ____tonnes CO_2 out of the EOR Scheme Area, which is also the EOR offset project, and moved to ___________________.

There has been a second individual transfer of ____tonnes CO_2 out of the EOR Scheme Area, which is also the EOR offset project, and moved to ___________________. Etc.

The total transfer of _______tonnes CO_2 out of the EOR Scheme Area, which is also the EOR offset project, during the calendar year.

This has been accounted for as ________________ (ie., a holdback transfer, a forfeit of holdback or a reversal) by the offset project developer in the most recent project report dated yyyy/mm/dd and in the CO_2 balance sheet submitted as part of the offset project report.

3.0 Containment Assurance Conclusion:

In the calendar year, yyyy/mm/dd – yyyy/mm/dd, covered by this Containment Assurance Report:

There were _________ tonnes of new CO_2 injected into the project area.

There were _________ tonnes of CO_2 released from the project area via subsurface migration out of permitted geology, removed from the project area via production to surface and flared, vented or as a fugitive emission.

There were _________ tonnes of CO_2 transferred out of the EOR Scheme Area.

Signatory of the Alberta Emission Offset Project Developer:

____

(NAME/TITLE)

(COMPANY)