Quantification Protocol for CO_2 Capture and Permanent Storage in Deep Saline Aquifers

June 23, 2015

Title:	**Quantification Protocol for CO_2 Capture and Permanent Storage in Deep Saline Aquifers**
Number:	**Climate Change, 2015, No. 1**
Program Name:	**Alberta Carbon Offset Program**
Effective Date:	**June 23, 2015**
This document was updated on:	

Disclaimer:

Regulation and the legislation for all purposes of interpreting and applying the law. In the event that there is a difference between this document and the Specified Gas Emitters Regulation or legislation, the Specified Gas Emitters Regulation or the legislation prevail.

All Quantification Protocols approved under the Specified Gas Emitters Regulation are subject to periodic review as deemed necessary by the Department, and will be re-examined at a minimum of every five years from the original publication date to ensure methodologies and science continue to reflect best-available knowledge and best practices. This five-year review will not impact the credit duration stream of projects that have been initiated under previous versions of the protocol. Any updates to protocols occurring as a result of the five-year and/or other reviews will apply at the end of the first credit duration period for applicable project extensions.

Any comments or questions regarding the content of this document may be directed to:

Alberta Environment and Parks
Air and Climate Change Policy Branch
12th Floor, 10025 – 106 Street
Edmonton, Alberta, T5J 1G4
E-mail: **ESRD.GHG@gov.ab.ca**

Date of Publication: June 2015

ISBN: 978-0-7785-7220-6 (Printed)
ISBN: 978-0-7785-7221-3 (On-line)

Table of Contents

List of Appendices

List of Tables

List of Figures

Related Publications

- Alberta's 2008 Climate Change Strategy
- Additional Guidance on Cogeneration Facilities
- Carbon Capture and Storage Summary Report of the Regulatory Framework Assessment
- *Climate Change and Emissions Management Act*
- Specified Gas Emitters Regulation
- Specified Gas Reporting Regulation
- Specified Technical Guidance Regulation
- Technical Guidance for Completing Baseline Emissions Intensity Applications
- Technical Guidance for Completing Specified Gas Compliance Reports
- Technical Guidance for Greenhouse Gas Verifications at Reasonable Level Assurance
- Technical Guidance for Offset Project Developers
- Technical Guidance for Offset Protocol Developers

1.0 Offset Project Description

Carbon dioxide (CO_2) is emitted as a by-product in many industrial production processes. This CO_2 may be captured for other uses, or vented directly to the atmosphere. Capturing CO_2 emissions, and transferring them to permanent storage in deep saline aquifers results in a permanent reduction in CO_2 emissions.

Carbon capture and storage projects applicable under this protocol consist of three main components:

- CO_2 capture infrastructure, which includes a process modification to a facility to capture vented CO_2 emissions. The carbon capture facility is usually separate from the emission source facility, and typically uses a chemical solvent CO_2 capture technology;
- A CO_2 pipeline to transport CO_2 from the capture facility to the injection well(s); and
- Disposal of CO_2 through injection wells and into deep saline aquifers.

Project developers using this protocol must have familiarity with CO_2 capture and storage projects and greenhouse gas quantification methodologies.

1.1 Protocol Scope

This protocol scope covers the full carbon capture and storage chain from capture through compression, transport, injection and storage. See Figure 3 for a generic project process flow diagram.

Carbon capture and storage has the potential to remove a substantial amount of greenhouse gas emissions from Alberta's carbon footprint. The activity is named in Alberta's Climate Change Strategy 2008, as one of the main focus areas that will help meet our future emission reduction targets. It is a very expensive activity to undertake, even with the Alberta Government's significant investment of almost $1.3 billion. Additionally, there is no revenue stream from the activity other than the sale or use of carbon offset credits generated. Therefore the offset credit generation period is set at 20 years, with the possibility of ongoing 5 year extension. The criteria for project extension period eligibility, is listed in the Technical Guidance for Offset Project Developers (version 4.0).

Baseline Condition
Baseline emissions are determined using a projection-based baseline to quantify the emissions that would have otherwise been emitted to the atmosphere in the absence of the project. These emissions are quantified using the metered quantity of CO_2 injected into the deep saline aquifer for the purposes of permanent storage.

Project Condition
The project condition is the capture, compression, transport and injection of the CO_2 into a deep saline aquifer for permanent storage. Project emissions associated with capture, compression, transport and injection are subtracted from the baseline emissions to determine the net greenhouse gas reduction achieved by the project.

Carbon capture and storage projects primarily reduce carbon dioxide emissions, but small amounts of methane and nitrous oxide emissions may also be emitted as a result of combustion and upstream production emissions. Three species of greenhouse gas emissions - carbon dioxide, methane and nitrous oxide - must be quantified in the project.

Refer to the Technical Guidance for Completing Specified Gas Compliance Reports for the associated global warming potential of these gases.

1.2 Protocol Applicability

Project developers must be able to demonstrate the offset project meets the requirements of the Alberta carbon offset system, the Specified Gas Emitters Regulation, the quantification protocol and other related guidance documents. In particular, the project developer must provide sufficient evidence to demonstrate:

1. The project captures CO_2 directly from an industrial or non industrial facility;
2. The project is injecting into a deep saline aquifers capable of permanently storing CO_2 gases. Each injection site included in the project must have:
    - An approved carbon sequestration lease(s) in accordance with the *Mines and Minerals Act* and the Carbon Sequestration Tenure Regulation as issued by the Government of Alberta[1]; and
    - An approval for a CO_2 Storage Scheme as per application and approval under the Alberta Energy Regulator's Directive 065, Unit 4[2] and the *Oil and Gas Conservation Act*.
3. The project must be in good standing with all operating permits and relevant regulations in Alberta;
4. The reductions achieved by the project are quantified based on actual measurements and monitoring as indicated in this protocol; and
5. Metering of injected gas volumes to calculate injected CO_2 volumes takes place as close to the injection point as is reasonable to address the potential for fugitive emissions at the injection site (see Figure 3).

This protocol does not apply to either enhanced oil recovery activities or to acid gas injection schemes associated with sour natural gas processing operations. Project developers with CO_2 enhanced oil recovery projects should refer to the applicable Alberta carbon offset system quantification protocols for those activities.

Protocols will undergo a mandatory review every 5 years to assess the state of science, general assumptions on emission factors, coefficients, etc., and to assess adoption rates and additionality of the activity.

1.3 Protocol Flexibility

The following flexibility mechanisms may be used. It is the responsibility of the project developer to justify the rationale for the flexibility mechanism(s) used.

1. Greenhouse gases captured from a single or multiple sources may be sequestered by multiple project developers across several injection projects. Projects where the CO_2 is being transported to carbon capture and storage activities as well as third party injection activities (enhanced oil recovery or disposal activities) must demonstrate that all project emission sources and sinks are properly accounted for in the offset project plan. A system emission factor may be required to prorate emissions across each project developer participating in the network. The developers will need to provide justification for the method and values used to determine the system emission factor in the offset project plan. Refer to Appendix A for more information.

2. Carbon capture and storage projects that employ CO_2 capture, transport and disposal technologies and processes other than those contemplated in this protocol, are not precluded from applying this

[1] Carbon Sequestration Tenure Regulation, Alberta Regulation 68/2011, *Mines and Minerals Act*
[2] Directive 065: Resources Applictions for Oil and Gas Reservoirs, Alberta Energy Regulator, April 2014

protocol. Project developers planning to use alternate technologies are advised to contact Alberta Environment and Parks with a description of:

- The alternative technology or process configuration being proposed;
- How permanence of CO_2 storage can be ensured;
- How the responsibility for reversals and true up will managed; and
- Any modifications to the sources and sinks that would be required.

Alberta Environment and Parks will make a final decision on the eligibility of the proposed project based on program and protocol requirements.

3. Where the project boundaries differ from the process flow diagram for the project condition (see Figure 3), Alberta Environment and Parks approval must be obtained prior to project crediting. This ensures all direct and indirect emissions associated with the offset project are accounted for in the offset project report or the compliance reporting for the associated Large Final Emitter(s) as intended. Clarity on boundaries for projects associated with non-regulated facilities should be obtained prior to project start. Proponents are advised to refer to the latest version of Technical Guidance for Offset Project Developers for information regarding deviations from protocols.

1.4 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 (Formerly Energy Resouces Conservation Board)	An independent 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 storage activities.
Carbon Sequestration Tenure Regulation	Refers to the Carbon Sequestration Tenure Regulation (April 2011) under the *Mines and Minerals Act*, which enables application for pore space tenure. There are several administrative details and processes including requiring a permit and lease holders to determine storage site suitability, and develop and submit monitoring, measurement and verification plans.
Carbon Sequestration Lease	The Carbon Sequestration Tenure Regulation grants a lessee the right to drill, test and inject captured carbon dioxide into subsurface reservoirs for permanent sequestration, within the area of the lease.
Chemical Solvent Capture	An absorption process whereby a substance is incorporated into another of a different state (gases being absorbed by a liquid).
Deep Saline Aquifer	Porous rock formation(s) at least 1000 metres underground that contains saline water, which has a total dissolved solids content exceeding 4,000 milligrams per litre. Deep saline aquifers display trapping mechanisms suitable for permanent storage of injected $CO_{2.}$

Directive 007	Volumetric and Infrastructure Requirements (September 2011) that sets out the Alberta Energy Regulator's requirements for reporting volumetric data and well status changes using the Petroleum Registry of Alberta (Registry), and it prescribes the manner in which data must be submitted.
Directive 017	Measurement Requirements for Oil and Gas Operations (April 2011) that consolidates, clarifies 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 (June 2010) that 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) that 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 (October 2011) that details the process to apply to the Alberta Energy Regulator for all necessary approvals to establish the strategy and plan to deplete a 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.
Disposal	The elimination of waste fluids through injection into underground formation for puposes other than enhanced recovery or gas storage as it pertains to the Alberta Energy Regulator Directive 065.
Drilling 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) (underground blowout) that cannot be controlled by increasing the fluid density, as defined by The Alberta Energy Regulator Directive 059.
Drilling 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.
Gas Source	Includes any type of process that generates CO_2.

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.
Incremental, Directly Connected Electricity	Electricity sourced for the project that meets all of 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 lesser of: • the quantity of generated electricity in the offset crediting period beyond average generation in the three baseline years or generation from new capacity installed; and • the quantity of generated electricity that was under contract to the project in the crediting period.
Incremental Heat	Heat and steam from either newly installed heat generating capacity or capacity that has not been utilized over the three year period prior to, but ending within 6 months of, the initiation of project. For facilities with less than three years of operation, the full period of operation post commissioning should be used.
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 Gas	The total quantity of CO_2 that is measured directly upstream of the injection wellhead. This quantity is from the project condition and used to determine the baseline activity level.
Monitoring, Measurement and Verification (MMV) Plan	A plan submitted as a requirement under the Carbon Sequestration Tenure Regulation, and as required for the carbon capture and storage scheme approval. Monitoring and measurement are surveillance activities necessary for ensuring safe and reliable operation of a

	carbon sequestration project (containment and pore space utilization). Verification refers to the comparison of measured and predicted performance (conformance).
Permanent Storage	Also called geologic sequestration, refers to the isolation of carbon dioxide in subsurface formations. Injected carbon dioxide is trapped within pore spaces, dissolved in formation fluids and (over long time periods) mineralized (World Resources Institute, 2008, Guidelines for Carbon Dioxide Capture, Transport, and Storage).
Process Element	Components of the baseline or project that illustrate flow of CO_2 but are not the sources or sinks included in the quantification of baseline and project emissions.
Regulatory Framework Assessment for Carbon Capture and Storage	A multi-stakeholder process convened by the Government of Alberta. The mandate of the Assessment was to examine the existing regulatory framework for carbon capture and storage in Alberta and to make recommendations on how the regulatory framework could be enhanced. Recommendations from the Assessment included criteria for transfer of long-term liability for stored CO_2 to the Crown, and that reversals in storage should be accounted for and reconciled.
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, carbon monoxide (CO), and other trace compounds. The CO 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.
Waste Heat	Heat and steam imported into the project site that would otherwise have been vented, or dissipated to the environment directly through a condenser, or through some similar means.

2.0 Baseline Condition

The baseline scenario for this protocol is projection-based. It is the continued practice of emitting CO_2 to the atmosphere from the emissions source such as steam methane reforming for hydrogen production. Baseline emissions are projected using the total quantity of CO_2 that has been measured directly upstream of the injection wellheads in the project condition. These emissions are a portion of the total emissions from the emissions source. This dynamic baseline ensures the baseline correctly accounts for the year to year variation in CO_2 that is captured and injected in the project condition.

2.1 Identification of Baseline Sources and Sinks

Sources and sinks of emissions for the baseline were assessed based on guidance from ISO 14064-2, Alberta Environment and Parks and Environment Canada and are classified as follows:

Controlled: The behaviour or operation of a controlled source and/or sink is under the direction and influence of a 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 project developer.

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

Figure 1 shows the process flow diagram for the baseline condition, while Figure 2 categorizes these elements into the above-listed classifications.

Figure 1: Process Flow Diagram for the Baseline Condition

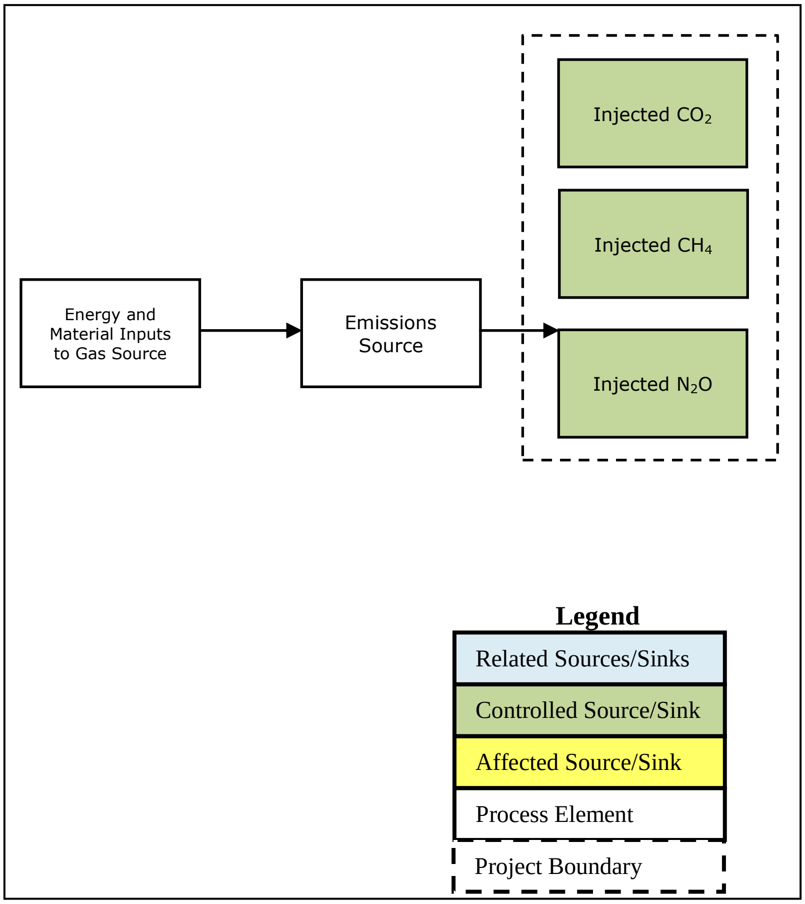


Table 1: Baseline Process Elements

Process Element	Description
Energy and Material Inputs to Gas Source	Energy and material inputs to the gas source require inputs such as electricity, heat and fuel, which may be supplied from on-site or off-site sources. Process elements are included for illustrative purposes only, and they do not affect the quantification.
Emissions Source	The emissions source includes any type of process that generates CO_2-rich gas, such as steam methane reforming. Process elements are included for illustrative purposes only, and they do not affect the quantification.

Figure 2: Baseline Sources and Sinks

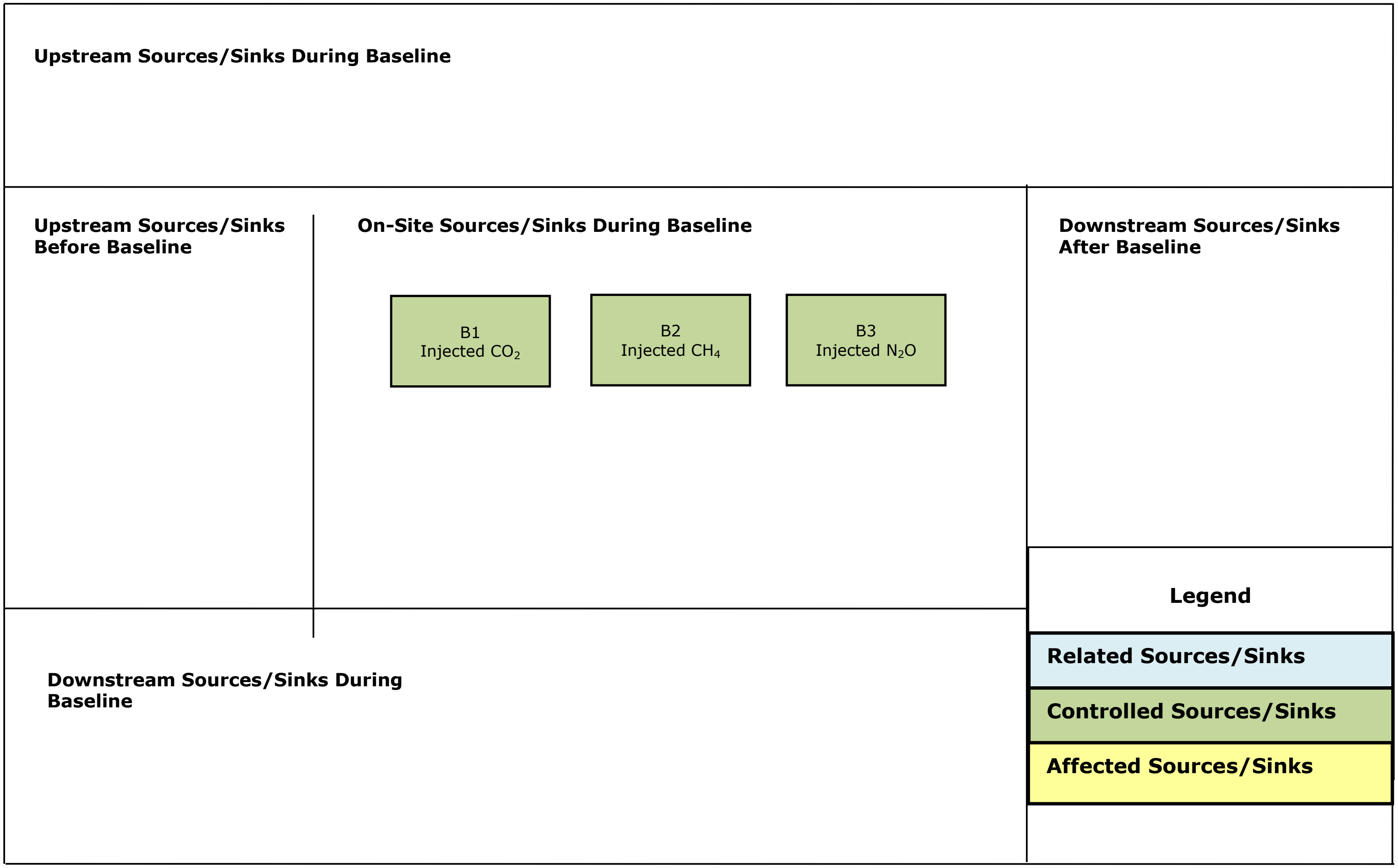


Table 2: Baseline Sources and Sinks

Source/Sinks	Description	Type
Upstream Source/Sinks During Baseline Operation – Not Applicable		
On-Site Sources and Sinks During Baseline		
B1 Injected CO_2	All CO_2 emissions released to the atmosphere in baseline, as projected from the project condition. Baseline emissions are projected back, using the direct measurement of the quantity of gas that has been measured upstream of the injection wellheads in the project condition. These emissions are a portion of the total emissions from the emissions source.	Controlled
B2 Injected CH_4	All CH_4 emissions released to the atmosphere in baseline, as projected from the project condition. Baseline emissions are projected back, using the direct measurement of the quantity of gas that has been measured upstream of the injection wellheads in the project condition. These emissions are a portion of the total emissions from the emissions source.	Controlled
B3 Injected N_2O	All N_2O emissions released to the atmosphere in baseline, as projected from the project condition. Baseline emissions are projected back using the direct measurement of the quantity of gas that has been measured upstream of the injection wellheads in the project condition. These emissions are a portion of the total emissions from the emissions source.	Controlled
Downstream Sources and Sinks During Baseline – Not Appliclable		
Downstream Sources and Sinks After Baseline – Not Applicable		

3.0 Project Condition

Carbon capture and storage projects consist of three distinct components: the capture and compression of CO_2; the transport of CO_2 to the injection wells; and the metering and disposal of CO_2 for permanent storage in a deep saline aquifer.

The main process elements of a typical carbon capture and storage project have been described below. Carbon capture and storage projects may employ other CO_2 capture, transport, disposal technologies, and processes. Flexibility to accommodate these different approaches is discussed in Section 1.3.

Capture

CO_2 capture refers to the separation of CO_2 from other gas species generated at the emissions source. The CO_2 capture infrastructure may consist of the following main process blocks:

- CO_2 capture technology using chemical solvent. This typically includes amine solvents, absorbers and associated equipment;
- 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;
- CO_2 compression, which may include a multi-stage compressor with an electrical motor and interstage coolers and knockout drums; and
- CO_2 dehydration, which may include a triethylene glycol (TEG) absorber and regeneration unit.

All emissions associated with the capture process are to be accounted for under the project condition.

Transport

The CO_2 transportation infrastructure for projects under this protocol may include equipment such as electrical or mechanical compressors or pumps, a pipeline network connecting the capture site to the injection site, line block valves and metering equipment. Supervisory control and data acquisition (SCADA) systems or other systems may be used to collect, transmit data from the pipeline to a control centre and monitor line break valves. CO_2 is typically transferred in dense phase and emissions arising from the compression and pumping of CO_2 at the capture site as part of the transport system are accounted for in the project condition.

Storage in Deep Saline Aquifers

Injected carbon dioxide is trapped within the pore spaces of the deep saline aquifer and is dissolved in formation fluids. Geologic storage options, with the exception of adsorption, are most efficient at depths where the formation pressure and temperature are sufficient to cause CO_2 to remain in a dense state. Specific storage reservoir characteristics must be addressed during application for pore space tenure.

Carbon dioxide is stored by one or more of the following trapping mechanisms[3]:

- Physical or volumetric trapping below an impermeable, confining layer (caprock);
- Capillary or residual trapping (retention in an immobile phase, trapped in the pore spaces of the storage complex);
- Mineral trapping or mineralization (precipitation as a carbonate material);
- Solubility trapping (dissolving of CO_2 into solution in the formation fluids that saturate the pore space within a rock formation); and/or
- Adsorption onto organic matter in coal and shale (i.e., CO_2 bonds with formation).

All emissions associated with disposal operations, including vented and fugitive emissions at the injection site (after the injection volume meter) and from the subsurface, are accounted for in the project condition consistent with the terms of the carbon sequestration lease and Directive 065 approval.[4]

3.1 Identification of Project Sources and Sinks

Sources and/or sinks for the project condition were identified based on review of existing best practice guidance contained in relevant greenhouse gas quantification protocols and carbon capture and storage project configurations. This process confirmed that sources and/or sinks in the process flow diagram covered the full scope of eligible project activities under this protocol. Process elements are described in Table 3.

These sources and/or sinks have been further refined according to the lifecycle categories identified in Figure 3. These sources and/or sinks were further classified as controlled, related or affected as described in Figure 4.

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

[4] For additional guidance on site selection, good operating practices and monitoring activities, refer to Z741 Geological Storage of Carbon Dioxide Standard, Canadian Standards Association, 2012.

Figure 3: Process Flow Diagram for the Project Condition

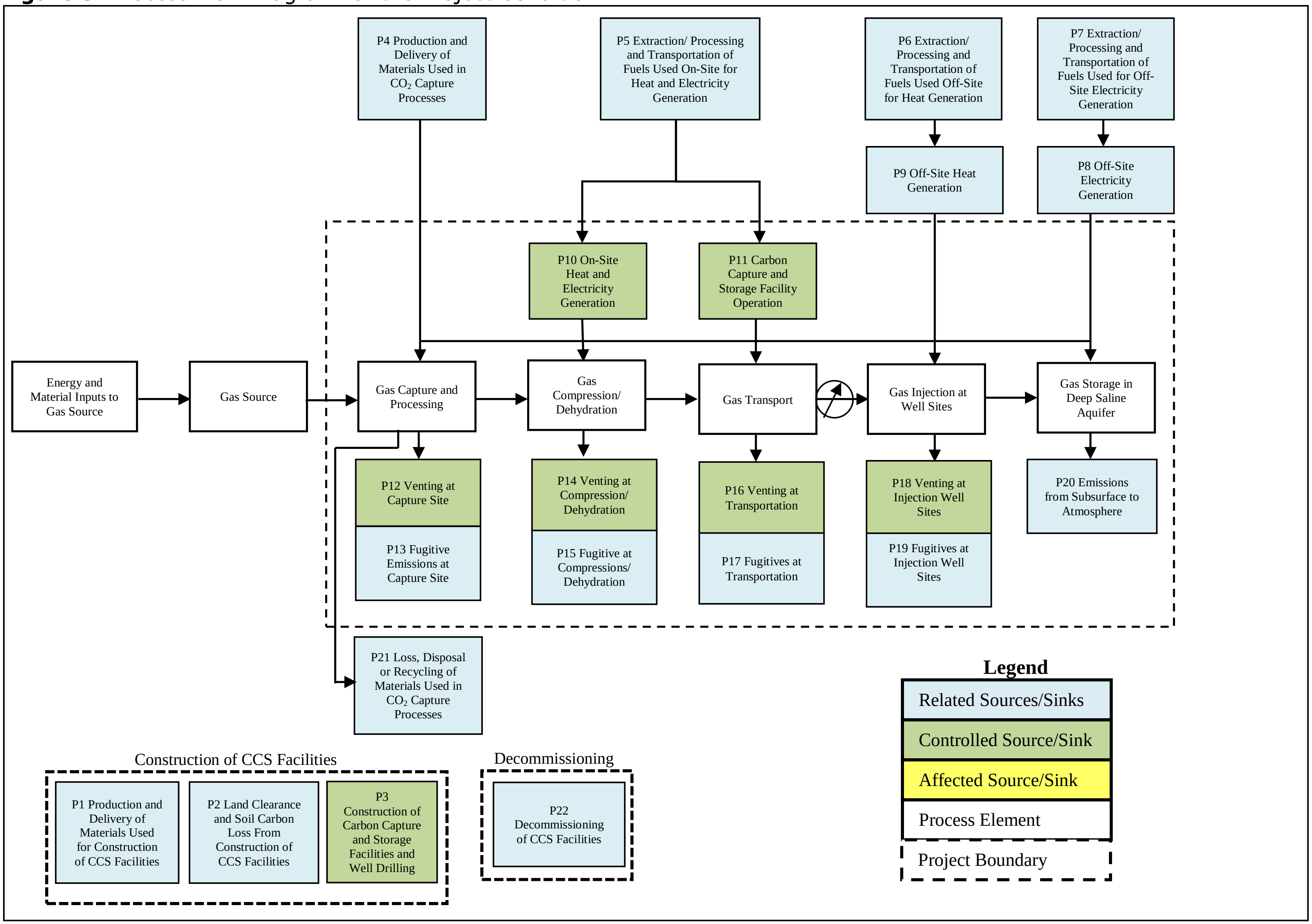


Table 3: Project Process Elements

Process Element	Description
Energy and Material Inputs to Gas Source	Energy and material inputs to the gas source require inputs such as electricity, heat and fuel, which may be supplied from on-site or off-site sources. Process elements are included for illustrative purposes only, and they do not affect the quantification.
Gas Source	The gas source includes any type of process that generates CO_2-rich gas, such as steam methane reforming. Process elements are included for illustrative purposes only, and they do not affect the quantification.
Gas Capture and Processing	The CO_2-rich gas stream coming from the gas source will need further purifying and processing before it can be injected. The capture technology applied at the capture facility typically uses chemical solvent such as amine regeneration. Process elements are included for illustrative purposes only, and they do not affect the quantification.
Gas Compression and Dehydration	The CO_2-rich gas stream must be compressed before it can be transported to the disposal site. Dehydration may also be required to prevent hydrate formation. This may be achieved through heating or other processes. Process elements are included for illustrative purposes only, and they do not affect the quantification.
Gas Transport	The CO_2-rich gas stream will be transported via pipeline to the injection site. Depending on the length of the pipeline, additional compression may be needed. Process elements are included for illustrative purposes only, and they do not affect the quantification.
Gas Injection at Wells	The CO_2-rich gas stream will be injected into the underground saline formation. In certain cases, additional energy inputs may be required at the injection wells for the injection operation or to operate monitoring equipment. Process elements are included for illustrative purposes only, and they do not affect the quantification.
CO2 Storage in Deep Saline Aquifers	The CO_2-rich gas stream will be disposed in deep saline aquifers suitable for permanent storage of injected CO_2. Process elements are included for illustrative purposes only, and they do not affect the quantification.

Figure 4: Project Condition Sources and Sinks

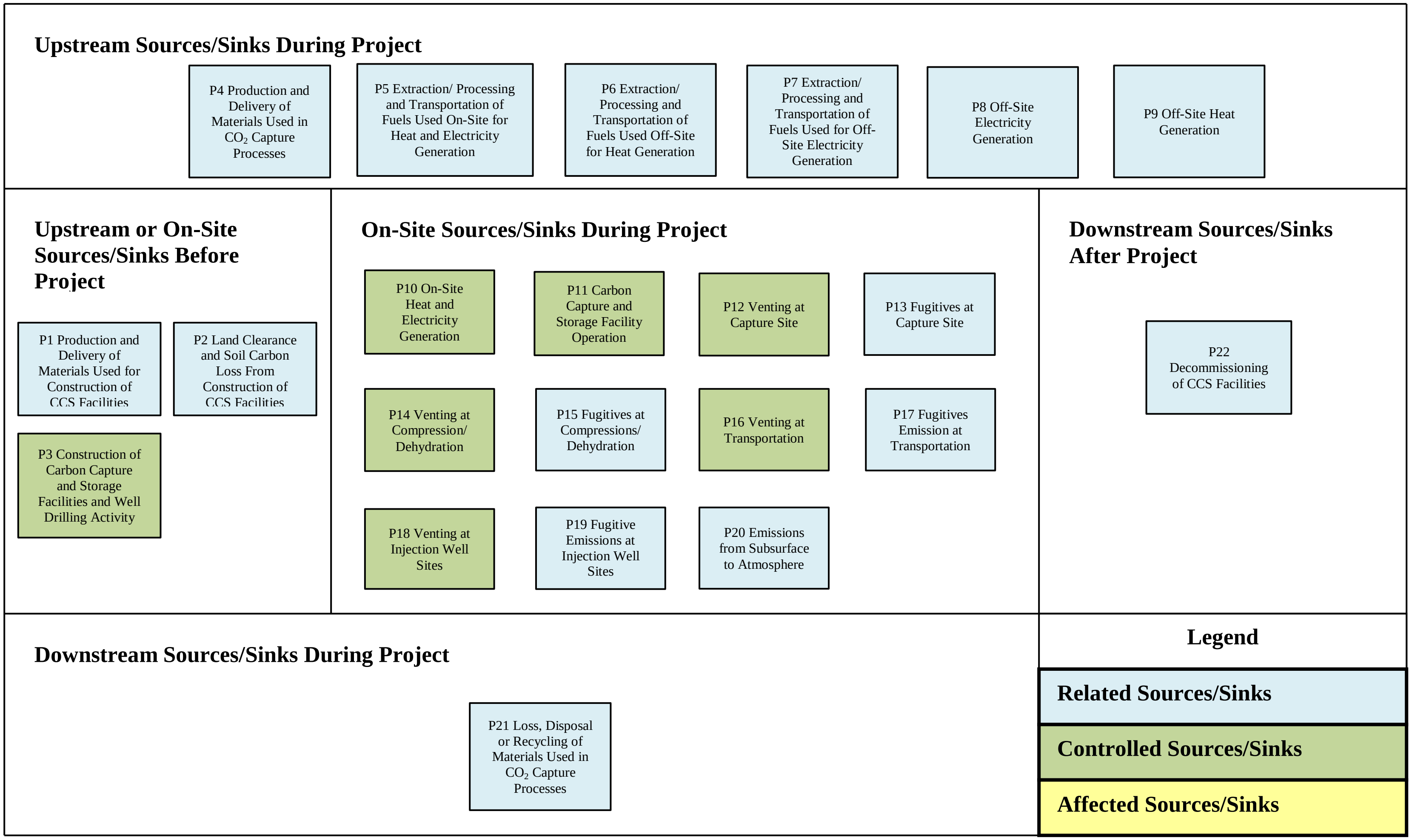


Table 4: Project Condition Sources and Sinks

Source/Sink	Description	Type
Upstream Sources and Sinks Before Project		
P1 - Production and Delivery of Materials Used for Construction of Carbon Capture and Storage Facilities	Materials used in the construction of carbon capture and storage 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
On-site Sources and Sinks Before Project		
P2 - Land Clearing and Soil Carbon Loss from Construction of Carbon Capture and Storage Facilities	The clearing of vegetative or forest land for site preparation may cause soil to release carbon dioxide into the atmosphere that was previously stored in soil.	Related
P3 - Construction of Carbon Capture and Storage Facilities and Well Drilling Activity	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.	Controlled
Upstream Sources and Sinks During Project		
P4 - 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 to the site must be tracked.	Related
P5 - Extraction/Processing and Transportation of Fuels Used On-Site for Heat and Electricity Generation	The fuels used for heat and electricity generation will need to be extracted, processed, and delivered to the site. Delivery may include shipments by truck, rail or pipeline. CO_2, CH_4 and N_2O emissions are associated with these activities. Volumes and types of fuels used must be tracked.	Related
P6 - Extraction/Processing and Transportation of Fuels Used Off Site for Heat Generation	The fuels used for heat generation will need to be extracted, processed, and delivered to the off-site facility. Delivery may include shipments by truck, rail or pipeline. CO_2, CH_4 and N_2O emissions are associated with these activities. Volumes and types of fuels used must be tracked.	Related

P7 - Extraction/Processing and Transportation of Fuels Used Off Site for Electricity Generation	The fuels used for the generation of off-site electricity must be extracted, processed, and delivered to the generating stations. Delivery may include shipments by truck, rail or pipeline. CO_2, CH_4 and N_2O emissions are associated with these activities. The quantity of off-site electricity used to operate the carbon capture and storage facilities as well as the quantity and type of fuel used for the generation of incremental directly connected electricity must be tracked.	Related
P8 - Off-Site Electricity Generation	The total quantity of electricity used by the carbon capture and storage facility must be tracked to estimate related greenhouse gas emissions. All sources of off-site electricity delivered to the project site must be able to be separated in order to quantify electricity from each incremental directly connected source and from electricity sourced from the electricity grid. The sources of off-site electricity can include: Grid Electricity: • All sources of electricity delivered by the provincial grid must apply the most current grid intensity factor published by Alberta Environment and Parks. Incremental, Directly Connected Electricity Generation through Industrial System Designation: • Off-site electricity that is not being sourced from the grid and meets the definition of Incremental, Directly Connected Electricity will have different emission intensity factors depending on the following categories: o Cogeneration from a large final emitter; o Non cogeneration from a large final emitter; or o Electricity from a non large final emitter.	Related

P9 - Off-Site Heat Generation	The total quantity of heat from each source used by the carbon capture and storage facility must be tracked to estimate related greenhouse gas emissions. All sources of off-site heat delivered to the project site must be able to be separated in order to quantify heat generated independently or via cogeneration with electricity. The quantity and type of fuels consumed to generate heat must be tracked. The sources of off-site heat will have different emission intensity factors and can include: Heat from a large final emitter: • cogeneration; or • non cogeneration. Heat from a non large final emitter. Waste Heat: All waste heat sources needs to be measured relative to the energy content of each source. The heat must be proven to have been vented or dissipated to the environment during the baseline condition to be considered waste and be accounted for as zero emissions.	Related
On-Site Sources and Sinks During Project		
P10 - On-Site Heat and Electricity Generation	Heat, steam and electricity inputs may be required for CO_2 capture, processing, compression, dehydration, transportation and injection. Heat and electricity may be generated independently or from cogeneration within the project boundary. The quantity and type of fuels consumed to generate electricity and heat, and the quantity of heat and electricity consumed by the project from each generating source must be tracked. Where waste heat from another facility is being used, the quantity of heat from all sources needs to be measured relative to the energy content of each source.	Controlled
P11 - Carbon Capture and Storage Facility Operation	The CO_2 pipeline and injection well must undergo regular inspection and monitored for leaks. The geological formation must also be monitored and tested regularly for signs of CO_2 leakage and/or migration consistent with the approved Monitoring, Measurement, and Verification Plan. Greenhouse gas emissions are released from fossil fuels consumed for maintenance activities for leak prevention and repair. These stationary and mobile sources may have natural gas, propane, and diesel energy inputs. Quantities and types for each of the energy inputs must be tracked.	Controlled
P12 - Venting of CO_2 at Capture Site	Some CO_2 is vented from the hydrogen production units during the project condition. CO_2 venting may also be necessary for equipment maintenance or emergency shutdowns.	Controlled
P13 - Fugitive Emissions at Capture Site	Unintended leaks of gas from the CO_2 capture and processing unit may occur through faulty seals, loose fittings, or equipment. These gases will be primarily composed of H_2 and CO_2.	Related
P14 - Venting of CO_2 During	Planned and emergency CO_2 venting may be necessary for compressor and dehydrator	Controlled

Compression/ Dehydration	maintenance and/or emergency shutdowns.	
P15 – 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. These gases will be composed primarily of CO_2 with trace amounts of other gases.	Related
P16 - Venting of CO_2 During Transportation	Planned and emergency CO_2 venting may be necessary for pipeline maintenance and/or shutdowns.	Controlled
P17 - 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. These gases will be composed primarily of CO_2 with trace amounts of other gases.	Related
P18 - Venting of CO_2 at Injection Well Sites	Planned and emergency CO_2 venting may be necessary for 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 volume of CO_2 vented.	Controlled
P19 - Fugitive Emissions at Injection Well Sites	Unintended leaks of gas at the CO_2 injection well sites may occur through valves, flanges, pipe connections, mechanical seals, or related equipment. These gases will be composed primarily of CO_2 with trace amounts of other gases. These emissions must be quantified.	Related
P20 - 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.	Related
Downstream Sources and Sinks During Project		
P21 - 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. These emissions must be quantified.	Related
Downstream Sources and Sinks After Project		
P22 - Decommissioning Carbon Capture and Storage of 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

4.0 Quantification

The baseline and project conditions were assessed against each other to determine the scope for reductions quantified under this protocol. Sources and sinks were either included or excluded depending on how they were impacted by the project condition. Sources and sinks that are not expected to change between baseline and project condition have been excluded from the quantification. It is assumed that excluded activities will occur at the same magnitude and emission rate during the baseline and project and will therefore not be impacted by the project.

Emissions that increase or decrease materially as a result of the project must be included and associated greenhouse gas emissions must be quantified as part of the project condition.

All sources and sinks identified in Table 2, Table 4 and Table 5. Each source and sink is listed as included or excluded. Justification for these choices is provided.

Table 5: Comparison of Sources and Sinks

Identified Source/Sink	Baseline	Project	Include or Exclude from Quantification	Justification for Inclusion/Exclusion
Upstream Sources and Sinks Before Project				
P1 - Production and Delivery of Materials Used for Construction of Carbon Capture and Storage 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. Its exclusion is consistent with other approved protocols in the Alberta cabon offset system.
Upstream Sources and Sinks Before Project				
P2 - Land Clearance and Soil Carbon Loss from Construction of Carbon Capture and Storage 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. Its exclusion is consistent with other approved protocols in the Alberta carbon offset system.
P3 - Construction of Carbon Capture and Storage Facilities and Well Drilling Activity	N/A	Controlled	Exclude / Include reportable drilling releases	This one-time only source of greenhouse gas emissions is negligible compared to the expected size and long lifetime of the project. Its exclusion may be consistent with other approved protocols in the Alberta carbon offset system. Any drilling releases that trigger the Alberta Energy Regulator's Directive 059 reporting threshold for kicks or blowouts must be included in the project emissions.
Upstream Sources and Sinks During Project				
P4 - Production and Delivery of Material Inputs used in CO_2 Capture Process	N/A	Related	Include	This source/sink may have a material impact on project emissions resulting from increased upstream chemical production associated with project period chemical usage.

Identified Source/Sink	Baseline	Project	Include or Exclude from Quantification	Justification for Inclusion/Exclusion
P5 - Extraction/Processing and Transportation of Fuels Used On Site for Heat and Electricity Generation	N/A	Related	Include	This source/sink is likely to have a material impact on projects.
P6 - Extraction/Processing and Transportation of Fuels Used Off Site for Heat Generation	N/A	Related	Include	This source/sink is likely to have a material impact on projects.
P7 - Extraction/Processing and Transportation of Fuels Used for Generation of Off-Site Electricity	N/A	Related	Include	Emissions associated with the fuel used for grid electricity has been excluded to maintain consistency with other government-approved protocols in the Alberta carbon offset system. However, if incremental, directly connected electricity is being used, emissions associated with the fuel used for electricity generation must be included
P8 - Off-Site Electricity Generation	N/A	Related	Include	This source/sink is likely to have a material impact on projects.
P9 - Off-Site Heat Generation	N/A	Related	Include	This source/sink is likely to have a material impact on projects.
On-Site Sources and Sinks During Project				
B1 - Injected CO_2	Controlled	N/A	Include	This source/sink is the data point against which all project emissions are subtracted. It is used to establish the baseline emissions for the project.
B2 - Injected CH_4	Controlled	N/A	Exclude	It is conservative to exclude CH_4 from the injected quantity as this would be an impurity in the process stream. Exclusion of this source also avoids a perverse incentive for the inefficient separation of the CO_2 stream.

Identified Source/Sink	Baseline	Project	Include or Exclude from Quantification	Justification for Inclusion/Exclusion
B3 - Injected N_2O	Controlled	N/A	Exclude	It is conservative to exclude N_2O from the injected quantity as this would be an impurity in the process stream. Exclusion of this source also avoids a perverse incentive for the inefficient separation of the CO_2 stream.
P10 - On-Site Heat and Electricity Generation	N/A	Controlled	Include	This source/sink is likely to have a material impact on projects.
P11 - Carbon Capture and Storage Facility Operation	N/A	Controlled	Include	This source/sink is likely to have a material impact on projects.
P12 - Venting of CO_2 at Capture Site	N/A	Controlled	Exclude	The vented and fugitive emissions that occur upstream of the injected wellhead meter in the project condition would have been emissions in the baseline condition in the absence of the carbon capture and storage project. These emissions are therefore excluded from the quantification.
P13 - Fugitive Emissions at Capture Site	N/A	Related	Exclude	The vented and fugitive emissions that occur upstream of the injected wellhead meter in the project condition would have been emissions in the baseline condition in the absence of the carbon capture and storage project. These emissions are therefore excluded from the quantification.
P14 - Venting of CO_2 During Compression/Dehydration	N/A	Controlled	Exclude	The vented and fugitive emissions that occur upstream of the injected wellhead meter in the project condition would have been emissions in the baseline condition in the absence of the carbon capture and storage project. These emissions are therefore excluded from the quantification.

Identified Source/Sink	Baseline	Project	Include or Exclude from Quantification	Justification for Inclusion/Exclusion
P15 - Fugitive Emissions During Compression/ Dehydration	N/A	Related	Exclude	The vented and fugitive emissions that occur upstream of the injected wellhead meter in the project condition would have been emissions in the baseline condition in the absence of the carbon capture and storage project. These emissions are therefore excluded from the quantification.
P16 - Venting of CO_2 During Transportation	N/A	Controlled	Exclude	The vented and fugitive emissions that occur upstream of the injected wellhead meter in the project condition would have been emissions in the baseline condition in the absence of the carbon capture and storage project. These emissions are therefore excluded from the quantification.
P17 - Fugitive Emissions During Transportation	N/A	Related	Exclude	The vented and fugitive emissions that occur upstream of the injected wellhead meter in the project condition would have been emissions in the baseline condition in the absence of the carbon capture and storage project. These emissions are therefore excluded from the quantification.
P18 - Venting of CO_2 at Injection Well Sites	N/A	Controlled	Included	This source/sink must be included because it occurs downstream of the injection meter. Resulting emissions may have material impact on the project.

Identified Source/Sink	Baseline	Project	Include or Exclude from Quantification	Justification for Inclusion/Exclusion
P19 - Fugitive Emissions at Injection Well Sites	N/A	Related	Include	This source/sink only includes fugitive emissions emitted at the injection site from surface facilities. These emissions may occur downstream of metering equipment. Fugitive emissions upstream of metering would also have been emissions in the baseline condition and are excluded from project emissions quantification. Fugitive emissions downstream of the metering equipment and upstream of the subsurface must be included. Fugitive emissions downstream of the metering equipment and down hole are quantified in P20 Emissions from Subsurface to Atmosphere.
P20 - Emissions from Subsurface to Atmosphere	N/A	Related	Include	Under normal operation, this source/sink is negligible and is excluded from quantification. However, emissions from leakage events must be quantified and included consistent with the approved measurement, monitoring and verification plan.
Downstream Sources and Sinks During Project				
P21 - Loss, Disposal, or Recycling of Materials Used in CO_2 Capture Processes	N/A	Related	Include	This source/sink is likely to have a material impact on projects resulting from increased greenhouse gas emissions associated with downstream chemical loss, disposal or recycling of project period chemical usage.
Downstream Sources and Sink After Projects				
P22 - Decommissioning of Carbon Capture and Storage Facilities	N/A	Related	Exclude	This source/sink results in negligible greenhouse gas emissions compared to the expected size and long lifetime of the project. These emissions are excluded consistent with other approved protocols in the Alberta carbon offset system.

4.1 Project Quantification Methodology

The quantification of the reductions, removals and reversals of relevant sources and sinks for each of the greenhouse gases will be completed using the methodologies outlined below. These calculation methodologies serve to complete the following four equations for calculating the emission reductions from the comparison of the baseline and project conditions.

$$\text{Emission Reduction} = \text{Emissions}_{\text{Baseline}} - \text{Emissions}_{\text{Project}}$$

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{Injected CO2}}$$

$$\begin{aligned}\text{Emissions}_{\text{Project}} = {} & \text{Emissions}_{\text{Production and Delivery of Material Inputs}} + \\ & \text{Emissions}_{\text{Construction and Well Drilling}} + \\ & \text{Emissions}_{\text{Fuel Extraction and Processing}} + \text{Emissions}_{\text{Off-Site Electricity Generation}} + \\ & \text{Emissions}_{\text{Off-Site Heat Generation}} + \text{Emissions}_{\text{On-Site Heat and Electricity Generation}} + \\ & \text{Emissions}_{\text{Carbon Capture and Storage Facility Operation}} + \\ & \text{Emissions}_{\text{Venting of CO2 at Injection Well Sites}} + \text{Emissions}_{\text{Fugitives from Injection Well Sites}} + \\ & \text{Emissions}_{\text{Subsurface to Atmosphere}} + \text{Emissions}_{\text{Loss, Disposal or Recycling of Material Inputs}}\end{aligned}$$

$$\begin{aligned}\text{Total } CO_2 \text{ Equivalent Emissions} = {} & \sum (CO_2 \text{ emissions}) * GWP_{CO2} + \sum (CH_4 \text{ emissions}) * \\ & GWP_{CH4} + \sum (N_2O \text{ emissions}) * GWP_{N2O} \\ & \sum (N_2O \text{ emissions}) * GWP_{N2O}\end{aligned}$$

Where:

$\text{Emissions}_{\text{Baseline}}$ = emissions projected from the measured quantity of CO_2 injected in the project condition, but does not include CH_4 and N_2O

$\text{Emissions}_{\text{Injected CO2}}$ = emissions under B1 Injected CO_2

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

$\text{Emissions}_{\text{Construction and Well Drilling}}$ = emissions under P3 Construction of CCS Facility and Well Drilling Activity

$\text{Emissions}_{\text{Production and Delivery of Material Inputs}}$ = emissions under P4 Production and Delivery of Materials Used in the CO_2 Capture Process

$\text{Emissions}_{\text{Fuel Extraction and Processing}}$ = emissions under P5, P6 and P7 Extraction/ Processing and Transportation of Fuels Used On/ Off Site for Heat and Electricity Generation

$\text{Emissions}_{\text{Off-Site Electricity Generation}}$ = emissions under P8 Off-Site Electricity Generation

$\text{Emissions}_{\text{Off-Site Heat Generation}}$ = emissions under P9 Off-Site Heat Generation

$\text{Emissions}_{\text{On-Site Heat and Electricity Generation}}$ = emissions under P10 On-Site Heat and Electricity Generation

$\text{Emissions}_{\text{Carbon Capture and Storage Facility Operation}}$ = emissions under P11 Carbon Capture and Storage Facility Operation

$\text{Emissions}_{\text{Venting CO2 at Injection Well Sites}}$ = emissions under P18 Venting at Injection Well Sites

$\text{Emissions}_{\text{Fugitives from Injection Well Sites}}$ = emissions under P19 Fugitives at Injection Well Sites

$\text{Emissions}_{\text{Subsurface to Atmosphere}}$ = emissions under P20 Emissions from Subsurface to Atmosphere

$\text{Emissions}_{\text{Loss, Disposal or Recycling of Material Inputs}}$ = emissions under P21 Emissions from Loss, Disposal or Recycling of Materials Used in CO_2 Capture Process

$CO_{2\ \text{Equivalent}}\ \text{Emissions}$ = sum of all greenhouse gas emissions converted to CO_2 equivalent terms, and does not apply to injected volumes of CH_4 or N_2O

Table 6: Quantification Methodology

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
Baseline Sources and Sinks						
B1 - Injected CO_2	$Emissions_{Injected\ CO2} = \Sigma (Vol._{Injected\ Gas} * \%_{CO2} * \rho_{CO2})$					
	$Emissions_{Injected\ CO2}$	t of CO_2e	N/A	This value refers to the injected quantity of CO_2 measured at the metering point in the project condition. The measured volume, composition, temperature and pressure are used to calculate the mass of CO_2 (excludes CH_4 and N_2O).	N/A	Mass of CO_2 to be calculated from direct measurement, and corrected for temperature and pressure. Frequency of metering is highest level possible.
	Volume of injected gas / $Vol._{Injected\ Gas}$	L / m^3 / other	Measured	Direct metering of volume of gas measured at the metering point in the project condition, measured directly at each injection well.	Continuous metering	Direct metering is standard practice. Frequency of metering is highest level possible.
	Density of injected CO_2 / $\rho_{Injected\ CO2}$	kg/m^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.	N/A	Densities must be used consistently throughout project.
	Concentration of injected CO_2 / $\%_{Injected\ CO2}$	%Volume	Measured	The gas composition shall be directly measured downstream of the capture and processing equipment while the volume is measured as close as possible to the point where CO_2 is injected into the deep saline aquifer.	Daily	A minimum of daily samples averaged monthly on volumetric basis.
Project Sources and Sinks						

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
P3 - Construction of Carbon Capture and Storage Facilities and Well Drilling Activity	$Emissions_{\text{Drilling Injection Well Sites}} = \sum (Vol._{\text{Gas Kick}} * \%_{i\ CO_2, CH_4, N_2O} * \rho_{i\ CO_2, CH_4, N_2O})$					
	$Emissions_{\text{Venting at Injection Well Sites}}$	t of CO_2e	N/A	N/A	N/A	Quantity being calculated.
	Volume of Vent Gas / $Vol._{\text{Gas Kick}}$	L / m^3 / other	Estimated	If the drilling activity resulted in a kick or a blowout, Directive 059 submission is triggered. The values submitted in the Directive 059 report should be used to estimate the volume of gas released.	Engineering estimate per event	The measurement approach should follow Directive 059 instructions and should be as frequent as the event.
	Density of vented gas / $\rho_{i\ CO_2, CH_4, N_2O}$	kg/m^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.	N/A	Densities must be used consistently throughout project.
P4 - Production and Delivery of Material Inputs used in CO_2 Capture Process	$Emissions_{\text{Production \& Delivery of Material Inputs}} = \sum (Input_i * EF\ Input_{i\ CO_2, CH_4, N_2O})$					
	$Emissions_{\text{Production \& Delivery of Material Inputs}}$	t of CO_2e	N/A	N/A	N/A	Quantity being calculated in aggregate based on quantity of inputs used throughout the carbon capture and storage operations.
	Quantity of material inputs consumed for carbon capture and storage facility operation / $Input_i$	t/L/m^3/ Other	Estimated	Estimation of the quantity of material inputs consumed for the carbon capture and storage project.	Annual	Engineering report will specify the quantity of material input required for an appropriately sized carbon capture

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
						and storage facility. Represents most reasonable means of estimation.
	Emissions factor for each type of material input / EF Input $_{i\ CO2,\ CH4,\ N2O}$	t CO_2e per t/L/ m^3/other	Estimated	Project specific design.	Annual	Production and delivery estimates for the emission factors for the material inputs.
P5, P6 & P7 - Extraction Processing and Transport of Fuels Used On/Off Site for Heat and Electricity Generation	$Emissions_{\ Fuel\ Extraction\ and\ Processing} = \sum (Fuel_{\ i} * EF\ Fuel_{\ i\ CO2,\ CH4,\ N2O})$					
	Emissions $_{Fuel\ Extraction\ and\ Processing}$	t of CO_2e	N/A	N/A	N/A	Quantity being calculated in aggregate based on quantity of fossil fuels used at each component of the carbon capture and storage operations.
	Total Quantity of fossil fuels consumed to operate carbon capture and storage facilities / Fuel i	M^3/MJ/ Other	Measured	Direct measurement of the quantity of fossil fuels consumed at each component of the carbon capture and storage project.	Continuous metering	Quantity being calculated in aggregate based on quantity of inputs used throughout the carbon capture and storage operations.
	Emissions factor for extraction and processing of each type of fuel / EF Fuel $_{i\ CO2,\ CH4,\ N2O}$	t CO_2e per m^3/ MJ/other	Estimated	From CAPP or other reference documents. Refer to Technical Guidance for Completing Specified Gas Compliance Reports	Annual	Reference values represent best available emission factors for fuel extraction and processing.

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
P8 - Off-Site Electricity Generation	$Emissions_{Off\text{-}Site\ Electricity\ Generation} = Electricity_{Grid} * EF_{Grid} + Electricity_{LFE\ Cogen} * EF_{LFE\ Cogen} + \sum (Electricity_{i\ LFE\ Non\ Cogen} * EF_{i\ LFE\ Non\ Cogen}) + \sum (Electricity_{i\ Non\ LFE} * EF_{i\ Non\ LFE})$ Where: Electricity LFE Cogen, LFE Non Cogen, Non LFE = Minimum (Electricity Total Gen. – Electricity Average Gen., Electricity Purchased through Dedicated Contract) Where: Electricity is the lesser of the difference between total and average generation and the electricity purchased through a dedicated contract. Where: Average generation is the amount of electricity generated by the facility from the 3 year reference period prior to project initiation. $EF_{LFE\ Non\ Cogen} = \begin{cases} 1)\ NEIL \quad if\ NEIL\ is\ in\ units\ of\ t\ CO_2e/MWh \\ \quad Where\ the\ NEIL\ for\ electricity\ generation\ is\ not\ available\ use, \\ 2)\ (1-T) * (\sum Fuel_{i\ LFE\ Non\ Cogen} * EF\ Fuel_{i\ CO2,CH4,N2O})\ /\ Electricity_{Total\ Gen.} \end{cases}$ $EF_{Non\ LFE} = (\sum Fuel_{i\ Non\ LFE} * EF\ Fuel^{i\ CO2,\ CH4,\ N2O})\ /\ Electricity_{Total\ Gen.\ Non\ LFE}$					
	Incremental Generating Capacity is determined by proof of: - the installed capacity that was not used in each of the 3 baseline years, - the generation that was under contract in each of the 3 baseline years, and - new capacity installed. The Average Year means the weighted average of the incremental generation capacity of the 3 baseline years. $Electricity_{LFE\ Cogen,\ LFE\ Non\ Cogen,\ Non\ LFE}$ is the lesser of the quantity of generated electricity in the offset crediting period beyond average generation in the 3 baseline years or generation from new capacity installed, and the quantity of generated electricity that was under contract to the project in the crediting period.					
P8 – Off-Site Electricity Generation	Emissions Off-Site Electricity Generation	t CO_2e	N/A	N/A	N/A	Total off-site electricity emissions quantity being calculated based on the individual quantities of electricity sourced

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
						from the provincial grid, from a large final emitter and from an industrial facility not regulated under SGER.
	Total quantity of grid delivered electricity consumed for carbon capture and storage project / Electricity $_{Grid}$	MWh	Measured	Direct measurement of grid delivered electricity consumed at each facility involved in the capture, compression, transport, injection, and storage of CO_2 plus the off-site directly connected electricity consumed that does not meet the definition of incremental electricity as calculated in; Electricity $_{LFE\ Cogen}$, Electricity $_{LFE\ Non\ Cogen}$, and Electricity $_{Non\ LFE}$. The total electricity consumption should be calculated as the sum of electricity consumption across individual components of the carbon capture and storage project. Projects require an individual meter for grid delivered electricity.	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.
	Grid emission intensity factor for electricity generation / EF $_{Grid}$	t CO_2e / MWh	Estimated	Grid emission intensity factor for each year obtained from Technical Guidance for Offset Project Developers document. No reduction target to be removed.	Annual	Reference value adjusted periodically by Alberta Environment and Parks.
	Quantity of incremental generating capacity consumed at the project / Electricity $_{LFE\ Cogen,\ LFE\ Non\ Cogen,}$	MWh	Calculated	Direct measurement of total electricity generated at source facility in project period and in the three year reference period, as well as direct measurement of electricity delivered to the project from each	Annual calculation of continuous metering data	Continuous direct metering represents the industry practice and the highest level of detail.

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Non LFE			source. Measured values must be used to calculate incremental generating capacity. The generating facility must meet the glossary definition for incremental generating capacity. All electricity that does not meet the definition of incremental generating capacity is considered to be grid electricity. The electricity included in this category from each directly connected source must be purchased through a dedicated contract. If the electricity is generated from a directly connected, source that has claimed offset credits or renewable energy certificates, the grid intensity factor would apply.		
	Quantity of total electricity generation / $Electricity_{Total\ Gen.}$	MWh	Measured	Total annual electricity generation of the facility supplying electricity to the project site.	Annual	Continuous direct metering represents the industry practice and the highest level of detail.
	Quantity of average electricity generation / $Electricity_{Average\ Gen.}$	MWh	Measured	Average annual electricity generation in the three year reference period prior to project initiation of the facility supplying electricity to the project site.	Annual	Continuous direct metering represents the industry practice and the highest level of detail.
	Emission intensity factor for cogeneration electricity generation / $EF_{LFE\ Cogen}$	t CO_2e / MWh	Estimated	Cogeneration emission intensity factor for each year obtained from Technical Guidance for Completing Specified Gas Compliance Reports document. In	Annual	Reference value adjusted periodically by Alberta Environment and Parks.

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
				the case of cogeneration the large final emitter reduction target is not removed. (This is the cogeneration benchmark used to calculate credit for cogeneration).		
	Emission intensity factor for electricity generation from a non- cogeneration facility/ $EF_{LFE\ Non\ Cogen}$	$t\ CO_{2e}$ / MWh	Calculated	Use one of these two methods provided: 1) Use the approved net emissions intensity limit (NEIL) for the specific facility for each compliance period if the NEIL is determined in tCO_2e/MWh. The large final emitter specific reduction target for the given compliance period is already deducted in the calculation of the NEIL. 2) If the NEIL is in units other than tCO_2e/MWh then the emission intensity factor should be calculated using the second equation above by measuring the total quantity of each fuel consumed for electricity generation	Annual	NEIL as approved annually by Alberta Environment and Parks.
	Net Emission Intensity Limit / NEIL	$t\ CO_2e$/ MWh	Calculated	Regulated facilities are assigned net emission intensity limits based on their reduction target and approved baseline emission intensity. The large final emitter specific reduction target for the given compliance period is already deducted in the calculation of the NEIL. Refer to the latest Technical Guidance for Completing Specified Gas Compliance Reports for guidance on calculating the NEIL.	Annual	Net Emissions Intensity Limit (NEIL) as approved annually by Alberta Environment and Parks.

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Reduction Target/T	%	Estimated	Reduction target assigned to the large final emitter for the given compliance year. The reduction target is a value set by the SGER. Check the regulation for the most up to date value.	N/A	Reference value adjusted periodically by Alberta Environment Parks and is dependent on the number of years the facility has been in operation.
	Total quantity of fuels consumed to generate incremental electricity / $Fuel_{i\ LFE\ Non\text{-}Cogen,\ Non\ LFE}$	L/ m^3/ Other	Measured	Direct measurement of the quantity of each fuel consumed for electricity generation at each incremental directly connected facility that provides electricity to the carbon capture and storage project. See Table 7 for common quantification variables.	Annual calculation of continuous metering data	Continuous direct metering represents the industry practice and the highest level of detail.
	Emission Factor for Fuel used to generate incremental electricity / $EF\ Fuel_{i\ CO2,\ CH4,\ N2O}$	t CO_2e/ m3	Calculated	See Table 7 for common quantification variables.	Annual calculation of continuous metering data	Continuous direct metering represents the industry practice and the highest level of detail.
	Emission intensity factor for electricity generation from a non- large final emitter facility / $EF_{Non\ LFE}$	t CO_{2e} / MWh	Calculated	The emission intensity factor for electricity produced at a non large final emitter facility is calculated (by measuring the total quantity of each fuel consumed for electricity generation).	Annual	Calculated based on the total amount of fuel consumed to produce the electricity by the non large final emitter facility.
P9 - Off-Site Heat Generation	$Emissions_{Off\text{-}Site\ Heat\ Generation} = \sum (Heat_{i\ LFE\ Cogen} * EF_{i\ LFE\ Cogen}) + \sum (Heat_{i\ LFE\ Non\ Cogen} * EF_{i\ LFE\ Non\ Cogen}) + \sum (Heat_{i\ Non\ LFE} * EF_{i\ Non\ LFE}) + \sum (Heat_{Waste} * EF_{Waste\ Heat})$ Where:					

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	$EF_{LFE\ Cogen} = \begin{cases} 1)\ NEIL & if\ NEIL\ is\ in\ units\ of\ t\ CO_2e/GJ \\ & else, \\ 2)\ (1-T) * EF_{Boiler\ Fuel}\ /0.8\ /\ HHV & \end{cases}$ $EF_{LFE\ Non\ Cogen} = (1\text{-}T) * EF_{Boiler\ Fuel}\ /\ 0.8\ /\ HHV$ $EF_{Non\ LFE} = EF_{Boiler\ Fuel}\ /\ 0.8\ /\ HHV$					
	Emissions $_{Off\text{-}Site\ Heat\ Generation}$	t CO_2e	N/A	N/A	N/A	Quantity being calculated based on quantity of heat sourced from off site.
	Quantity of heat consumed by the project facility where heat is a product / Heat $_{LFE\ Cogen,\ LFE\ Non\ Cogen,\ Non\ LFE,\ Waste\ Heat}$	GJ	Measured	Direct measurement of the quantity of heat used by the carbon capture and storage project.	Annual	Continuous metering is standard for boundary transfer.
	Emission intensity factor associated with heat from LFE Cogen / EF $_{LFE\ Cogen}$	t CO_2e/GJ	Calculated	Use one of two methods provided to determine the emission factor based on the facility specific emissions intensity. 1) If the net emissions intensity limit (NEIL) is in t CO_2e/GJ (or equivalent) for the compliance year, use the approved facility specific (NEIL for each compliance period. The large final emitter specific reduction target for the given compliance period is already deducted in the calculation of the NEIL. 2) Where there is no NEIL (a new facility), calculate the emissions from the total heat produced by the facility using the second equation	Annual calculation	Values taken from SGER reports. This information must be made available by the heat producing facility for project verification. The reduction target may be removed from the project accounting for the heat consumed as it was included in the facility's compliance requirement. See technical guidance for baseline reporting.

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
				above, which assumes 80% boiler efficiency.		
	Net Emission Intensity Limit / NEIL	t CO_2e / GJ	Calculated	Regulated facilities are assigned net emission intensity limits based on their reduction target and approved baseline emission intensity. The large final emitter specific reduction target for the given compliance period is already deducted in the calculation of the NEIL Refer to the latest Technical Guidance for Completing Specified Gas Compliance Reports for guidance on calculating the NEIL.	Annual	NEIL as approved annually by Alberta Environment and Parks.
	Emission intensity factor for the fuel used in the stand-alone boiler facility / $EF_{Boiler\ Fuel}$	t CO_2e/ L, m^3 or other	Calculated	See Table 7.	Annual	Calculated based on measured fuel composition and reference heating values as per industry best practice. See Table 7.
	Emission intensity factor associated with heat from LFE non cogeneration facility /$EF_{LFE\ Non\ Cogen}$	t CO_2e / GJ	Calculated	Emissions allocated to heat production are calculated by determining the input energy attributed to heat production based on a boiler thermal efficiency of 80%.	Annual	Calculated based on the total amount of heat produced and the total fuel consumed to produce that heat by the large final emitter non cogeneration facility.
	Emission intensity factor associated with heat from Non LFE /$EF_{Non\ LFE}$	t CO_2e / GJ	Calculated	Emissions allocated to heat production are calculated by determining the input energy attributed to heat production based on a boiler thermal efficiency of	Annual	Calculated based on the total amount of heat produced and the total fuel consumed to produce that heat by

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
				80%.		the facility.
	Emission intensity factor associated with the waste heat from facility / $EF_{Waste\ Heat}$	t CO_2e / GJ	Calculated	Zero emissions are associated with waste heat production as per the glossary definition.	Annual or project period	Waste heat is a by-product of industrial processes and has a zero environmental footprint.
P10 - On-Site Heat and Electricity Generation	$Emissions_{On\text{-}Site\ Heat\ and\ Electricity\ Generation} = \sum (Fuel_{CCS} * EF\ Fuel_{i,\ CO2,\ CH4,\ N2O})$ Where: $Fuel_{CCS} = (Heat_{CCS} / Heat_T) * Fuel_H + (Elec_{CCS} / Elec_T) * Fuel_E$ *If direct measurement is not available, an optional calculation is provided:* $Fuel_H = Fuel_{H\ \&\ E} * (Heat_T / e_H) / (Heat_T / e_H + Elec_T / e_E)$ *Where: e = efficiency* $Fuel_E = Fuel_{H\ \&\ E} - Fuel_H$					
	$Emissions_{On\text{-}Site\ Heat\ and\ Electricity\ Generation}$	t of CO_2e	N/A	N/A	N/A	Quantity being calculated based on quantity of heat and
						power sourced from on-site cogeneration facilities.
	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 cogeneration 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

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
						combined heat and power plant. Direct metering of thermal energy and electricity is appropriate.
	Volume of Fossil Fuels Consumed to Generate Heat at On-Site Generation Facilities for Use by the CCS Project /	L/ m^3/ Other	Measured	Direct measurement of the volume of fossil fuels consumed at the heat and power generation facility and/or other direct connected facilities that provide heat to the carbon capture and storage project.	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.
	$Fuel_{H}$		Calculated	Calculated based on heat generation efficiency of generation unit.	Monthly	Calculated according to best practice guidance.
	Volume of Fossil Fuels Consumed to Generate Electricity at On-Site Generation Facilities for Use by the CCS Project / $Fuel_{E}$	L/ m^3/ Other	Measured	Direct measurement of the volume of fossil fuels consumed at the heat and power generation facility and/or other direct connected facilities that provide power to the carbon capture and storage project.	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.
			Calculated	Calculated based on heat generation efficiency of generation unit.	Monthly	Calculated according to best practice guidance.
	Total Volume of Fossil Fuels Consumed to Generate Heat and Power at the Combined Heat and Power Generation Facilities / $Fuel_{H\,\&\,E}$	L/ m^3/ Other	Measured	Direct measurement of the volume of fossil fuels consumed at the combined heat and power generation facility and/or other direct connected facilities that provide heat and/or power to the carbon capture and storage project.	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Total Quantity of Thermal Energy Supplied to the CCS Project from Generation Facilities / $Heat_{CCS}$	GJ	Measured	Direct metering of quantity of thermal energy received by the carbon capture and storage project from connected heat and power generation facilities (e.g., from dedicated cogeneration facilities, other industrial facilities etc.). Metering of the thermal energy should account for the type of heat transfer medium (steam, hot water, oil, etc.) and the net heat transfer based on mass/volume flow rates of the heat transfer medium to and from the carbon capture and storage equipment (e.g., accounting for the enthalpy of feedwater, boiler blow down and condensate return), temperatures, pressures for superheated steam and other relevant thermodynamic properties as necessary.	Continuous metering	Direct metering of thermal energy is standard practice when thermal energy is provided to a user under a contractual agreement. Frequency of metering is highest level possible. Accounting for the net heat transfer from the heat distribution system based on the specific temperatures and pressures of the heat transfer medium is consistent with best practices.
	Total Quantity of Electricity Supplied to the CCS Project by Generation Facilities / $Elec_{CCS}$	GJ	Measured	Direct metering of the quantity of electricity delivered to the carbon capture and storage Project from third party generation plants or other direct connected power generation facilities. Note that grid electricity usage is accounted for under a separate source/sink and should not be included in this calculation.	Continuous Metering	Continuous direct metering represents the industry practice and the highest level of detail.

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Total Quantity of Thermal Energy Supplied to End Users by the Generation Facility in the Project Condition	GJ	Measured	Direct metering of quantity of thermal energy delivered to all end users by the generation plant (including the carbon capture and storage facilities). Metering of the thermal energy should account for	Continuous Metering	Direct metering of thermal energy is standard practice when thermal energy is provided to a user under a contractual
	/ $Heat_T$			the type of heat transfer medium (steam, hot water, oil, etc.) and the net heat transfer based on mass/volume flow rates of the heat transfer medium to and from the capture facility (e.g., accounting for the enthalpy of feedwater, boiler blow down and condensate return), temperatures, pressures for superheated steam and other relevant thermodynamic properties as necessary.		agreement. Frequency of metering is highest level possible. Accounting for the net heat transfer from the heat distribution system based on the specific temperatures and pressures of the heat transfer medium is consistent with best practices.
	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 the carbon capture and storage facilities, the regional electricity grid and an industrial system designation.	Continuous Metering	Continuous direct metering represents the industry practice and the highest level of detail.

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Efficiency of Heat Generation at On-site Generation Unit / e_H	-	Estimated	Estimated based on total quantity of thermal energy output from generation unit and input energy content of fuels combusted by the generation unit. If a site-specific heat generation efficiency is unavailable, use a default efficiency of 80%.[5]	Annual	Estimation is reasonable given consistency of generation unit operations.
	Efficiency of Electricity Generation at On-site Generation Unit / e_E	-	Estimated	Estimated based on total quantity of electricity output from generation unit and input energy content of fuels combusted by the generation unit. If a site-specific electric efficiency is unavailable use a default efficiency of 35%.[6]	Annual	Estimation is reasonable given consistency of generation unit operations.
	Emissions $_{\text{Carbon Capture and Storage Facility Operation}}$	t of CO_2e	N/A	N/A	N/A	Quantity being calculated based on quantity of fossil fuels used for inspection and maintenance of carbon capture and storage facilities.
	Volume of Each Type of Fuel Used CCS Facility Operation/ Fuel $_i$	L / m^3 / other	Estimated	Volumes of fuel consumed by each piece of equipment used during the operating activities of the CCS facility may be estimated.	Annual	Quantity being estimated in aggregate form as fuel used at CCS facility is likely aggregated for each source.

[5] A default thermal efficiency of 80% may be used to allocate emissions to purchased thermal energy used by the carbon capture and storage project if a site-specific thermal efficiency cannot be obtained. This assumption is consistent with Alberta Environment and Parks guidance under the Specified Gas Emitters Regulation.

[6] A default electrical efficiency of 35% may be used to allocate emissions to electricity purchased from third party cogeneration units for use by the carbon capture and storage project if a site-specific electrical efficiency cannot be obtained. This assumption is consistent with the Climate Registry General Reporting Protocol Version 1.1.

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
P18 - Venting at Injection Well Sites	$Emissions_{\text{Venting at Injection Well Sites}} = \sum (Vol._{\text{Gas Vented}} * \%_{CO2, CH4, N2O} * \rho_{CO2, CH4, N2O})$					
	Emissions $_{\text{Venting at Injection Well Sites}}$	t of CO_2e	N/A	N/A	N/A	Quantity being calculated.
	Volume of Vent Gas / Vol. $_{\text{Gas Vented}}$	L / m^3 / other	Estimated	Volume should be estimated 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 as frequent as the maintenance event.
	Composition in Vent Gas / % $_{CO2,CH4,N2O}$	%	Measured	The gas composition shall be directly measured downstream of the capture and processing equipment and as close as possible to the point where CO_2 is injected into the deep saline aquifer.	A minimum of daily samples averaged monthly on volumetric basis	Composition may vary throughout the injection of gas stream. Frequent gas composition measurement is reasonable for operation of an injection facility.
	Density of Vent Gas / $\rho_{CO2,CH4,N2O}$	t/m^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.	N/A	Densities must be used consistently throughout project.
P19 - Fugitives at Injection Well Sites	$Emissions_{\text{Fugitives at Injection Well Sites}} = \sum (Fitting_i * ER_{Fitting\ i}) + Other\ Fugitive\ Releases$					
	Emissions $_{\text{Fugitives at Injection Well Sites}}$	t of CO_2e	N/A	N/A	N/A	Quantity being calculated.

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Other Fugitive Releases	t of CO_2	Estimated	Engineering estimate.	Per occurance	This is from unintended/unplanned events, and accounts for CO_2 released after the meter and wellbore but not from the storage container. Estimated based on the most detailed information available.
	Number of Fittings after Injection Meter / Fitting $_i$	N/A	Estimated	Project-specific design.	Once	Estimated based on the number of fittings after the injection meter and above the subsurface.
	Emission Rate for Fitting / ER $_{Fitting\ i}$	t of CO_2e /fitting/ year	Estimated	Emission rate based on industry best practices for determining typical fitting emissions based on actual field equipment (fitting sizes, types, operating pressures and gas properties).	Annual	Estimates made for project specifics represent the most accurate means.
P20 - Emissions from Subsurface to Atmosphere	$Emissions_{\ Subsurface\ to\ Atmosphere} = Mass\ CO_2e_{\ leaked}$					
	Mass of CO_2e leaked from the Subsurface to Atmosphere/ Mass CO_2e $_{leaked}$	t of CO_2e	Estimated	If a leak event occurs, the mass of CO_2e 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

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
						the event leakage occurs.
P21 - Loss, Disposal or Recycling of Material Used	$Emissions_{\text{Loss, Disposal or Recycling of Material Used}} = \sum (Vol.\ Used_i * EF\ Used_{i\ CO2,\ CH4,\ N2O})$					
	$Emissions_{\text{Loss, Disposal or Recycling of Material Used}}$	t of CO_2e	N/A	N/A	N/A	Quantity being calculated in aggregate based on quantity materials used for the carbon capture and storage operations.
	Total Volume of Material Lost, Disposed or Recycled from the Carbon Capture and Storage Facility/Vol. $Used_i$	L/ m^3/ Other	Estimated	Estimation of the volume of material inputs lost, disposed or recycled for the carbon capture and storage project.	N/A	Engineering report will specify the volume of material input lost, disposed or recycled for an appropriately sized carbon capture and storage facility. Represents most reasonable means of estimation. Loss, disposal or recycling estimates for the emission factors for the materials used.
	Emissions factor for each type of material input / EF $Used_{i\ CO2,\ CH4,\ N2O}$	t CO_2e per L / m^3 / other	Estimated	Project-specific design.	Annual	Production and delivery estimates for the emission factors for the material inputs.

Table 7: Common Quantification Variables

Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justify measurement or estimation and frequency
Total heat produced by the facility / H	GJ	Measured	Total quantity of heat produced by the facility is determined through direct metering.	Annual calculation of continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.
Reduction target / T	%	Estimated	Reduction target assigned to the LFE for the given compliance year. The reduction target is a value set by the SGER. Check the regulation for the most up to date value.	N/A	Reference value adjusted periodically by Alberta Environment and Parks and is dependent on the number of years the facility has been in operation.
Higher heating value / HHV	GJ/L, m3 or other	Measured	Measured by a third party gas analysis or calculated based on gas compositions. Units for HHV and Emission Factor for Fuel must align.	Annual	Frequency of metering provides for reasonable diligence.
CO_2 emission factor for each type of fossil fuel combustion/ EF Fuel $_{i\ CO2}$	t CO_2e per L, m^3 or other	Estimated	See Technical Guidance for Completing Specified Gas Baseline Emission Intensity Applications for Table 5: Emission Calculation Methods Acceptable to Alberta Environment and Parks and/or latest version of Carbon Offset Emission Factor Handbook.	Annual	Reference values are adjusted periodically use the most current version.
CH_4 emission factor for each type of fossil fuel combustion/ EF Fuel $_{i\ CH4}$	t CO_2e from kg CH_4 per L, m^3 or other	Estimated	See Technical Guidance for Completing Specified Gas Baseline Emission Intensity Applications for Table 5: Emission Calculation Methods Acceptable to Alberta Environment and Parks and/or latest version of Carbon Offset Emission Factor Handbook.	Annual	Reference values adjusted periodically use the most current version.
N_2O emission factor for each type of fossil fuel combustion / EF Fuel $_{i\ N2O}$	t CO_2e from kg CH_4 per L, m^3 or other	Estimated	See Technical Guidance for Completing Specified Gas Baseline Emission Intensity Applications for Table 5: Emission Calculation Methods Acceptable to Alberta Environment and Parks and/or latest	Annual	Reference values adjusted periodically Use the most current version.

Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justify measurement or estimation and frequency
			version of Carbon Offset Emission Factor Handbook.		
Total quantity of fuel consumed / Fuel $_i$	m^3/ MJ/ kg or other	Measured	Direct measurement of the quantity of fossil fuels consumed at each component of the carbon capture and storage project.	Continuous metering	Quantity being calculated in aggregate based on quantity of fossil fuels used.
		Estimated	Calculate the mass/volume of fuel used for heat or electricity production. Conversions from energy to fuel quantities should use the higher heating value of the fuel. Energy use should be either measured or calculated based on conservative estimate for equipment duty and load.	Annual	Annual fuel consumption estimate should be completed in the absence of direct metering for fuel consumption. Maximum power consumption rates should be used to estimate fuel consumption with higher heating values.

5.0 Data Management

Projects must be supported with data of sufficient quality to fulfill the quantification requirements and be substantiated by company records for the purpose of verification to a reasonable level of assurance. Reasonable assurance means the verifier must be able to reach a positive finding on the accuracy and correctness of the GHG assertion.

In support of this requirement project data must be managed in a manner that substantiates that:

- Emissions and reductions that have been recorded pertain to the offset project;
- All emissions and reductions that should have been recorded have been recorded;
- Emissions and reductions quantification has been recorded appropriately;
- Emissions and reductions have been recorded in the correct reporting period;
- Emissions and reductions have been recorded in the appropriate category; and
- Must have an auditable data management system.

Based on these requirements, data must be quantifiable, measurable and verifiable using replicable means. That is, an independent verifier should be able to reach the same conclusions using evidence-supported data. The Alberta carbon offset system cannot accept data that is based on attestation.

The project developer shall establish and apply quality management procedures to manage data and information. Written procedures must be established for each measurement task outlining responsibility, timing and record location requirements. Requirements can be found in Technical Guidance for Greenhouse Gas Verification at Reasonable Level of Assurance.

5.1 Project Monitoring

Monitoring requirements for carbon capture and storage projects are addressed in two separate categories: project emissions monitoring; and the monitoring, measurement and verification of containment. The first includes quantification and measurement activities required to quantify the net greenhouse gas reductions from the carbon capture and storage project and which are addressed in this protocol. The second category is for monitoring, measurement and verification activities that are required to ensure that the CO_2 injected into deep saline aquifers is permanently contained within the storage complex. Carbon capture and storage projects must comply with the Alberta-specific requirements for measurement, monitoring and verification plans and other regulatory requirements. Each carbon capture and storage project used to generate offsets in the Alberta carbon offset system must have an approved carbon sequestration lease(s) issued in accordance with the *Mines and Minerals Act* and the Carbon Sequestration Tenure Regulation[7].

5.1.1 Project Monitoring Requirements

The project monitoring plan for the carbon capture and storage project must be designed according to the requirements of the Alberta carbon offset system provided in the Technical Guidance for Offset Project Developers[8]. Data capture must be sufficient to ensure that the quantification and documentation of greenhouse gas reductions is replicable and verifiable. The monitoring requirements include measurements of relevant parameters to account for all supplemental energy

[7] Carbon Sequestration Tenure Regulation, Alberta Regulation 68/2011, *Mines and Minerals Act*

[8] The Technical Guidance for Offset Project Developers, Version 4, February 2013, Alberta Environment and Parks (formally Environment and Sustainable Resource Development).

inputs (e.g., fossil fuels and electricity) required for the operation of the carbon capture and storage project.

The project monitoring techniques should use off the shelf metering equipment such as gas flow meters, utility meters (gas and electricity) and gas analyzers. In general, data quality management must include sufficient data capture to support quantification and verification of emission reductions. Any assumptions and contingency procedures must be documented. Meters must be maintained to operate consistent with design specifications and must be calibrated on a regular basis.

Below is additional guidance for implementing a monitoring plan that takes into account the location, type of equipment, and frequency by which each variable is measured.

5.1.2 Project Monitoring Plan

A monitoring plan is to be established for all monitoring and reporting activities associated with the project. The monitoring plan will serve as a basis for verifiers and confirm that the monitoring and reporting requirements have been and will continue to be met, and that consistent, rigorous monitoring and record keeping is ongoing at the project site. The monitoring plan must cover all aspects of monitoring and reporting contained in this protocol and must specify how data for all relevant parameters listed above will be collected and recorded.

At a minimum the monitoring plan shall stipulate and include:

- The frequency of data acquisition;
- A record keeping plan;
- The frequency of instrument calibration activities;
- The QA/QC provisions on data acquisition, mamagement and record keeping that ensures it is carried out consistently and with precision.
- The role of individuals performing each specific monitoring activity; and
- Methods to measure and quantify the following data:
  - Incremental energy inputs required to capture, transport, inject and store CO_2 including:
    - Direct fuel inputs; and
    - Indirect energy inputs or other parasitic loads (e.g., electricity consumption);
  - Quantity of CO_2 emitted from the capture site;
  - Quantity of CO_2 input into the CO_2 transport pipeline;
  - Quantity of CO_2 sold to third parties (e.g., for enhanced oil recovery) including sufficient measurements to support data required; and
  - Quantity of CO_2 injected into each well in the deep saline aquifer metered at the wellhead.

Additional measurements may be made to support quantification purposes. 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.

Table 8 provides 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 carbon capture and storage project. The general monitoring requirements for fossil fuel and electricity inputs are listed in Table 9.

Table 8: Measurement and Monitoring Guidance for Injected Gas

Variable	Units of Measurement	Measurement Frequency	Additional Guidance
Flow rate of gas stream	L / m^3 / other	Continuous measurement of the gas flow rate, gas composition, and gas density where continuous measurement is defined as a minimum of one measurement every 15 minutes.	• Meter readings may need to be temperature and pressure compensated such that the meter output is set to standard reference temperatures and pressures. Estimates of composition and density are not permissible; • Flow meters must be placed based on manufacturer recommendations: ○ Flow meters should be located at the input to the gas transport equipment such that they are downstream of all capture and compression equipment to account for any fugitive losses or venting; and ○ Flow meters should be as close as possible to the injection wellheads to ensure accurate measurement of the injected volumes; • Flow meters must be calibrated according to manufacturer specifications. Meters must be checked/calibrated at regular intervals according to these specifications and industry standards; and • Ownership transfer must be clearly documented for CO_2 transferred (third party injection activity).
Concentration of gas stream	%	Continuous measurement of the gas composition and density where continuous measurement is defined as a minimum of one measurement every 15 minutes.	The gas composition shall be metered downstream of the capture and processing equipment while the volume is measured as close as possible to the point where CO_2 is injected into the deep saline aquifer.

Table 9: Measurement and Monitoring Guidance for Energy Inputs

Variable	**Units of Measure**	**Measurement Frequency**	**Additional Guidance**
Volume of fossil fuels combusted (gaseous)	ft^3 or m^3 or other	Continuous measurement of the gas flow rate where continuous measurement is defined as one measurement every 15 minutes.	• The flow meter readings must be corrected for temperature and pressure. Density estimates used for emission quantification purposes must be adjusted to corrected standardized temperatures and pressures; • Flow meters shall be placed based on manufacturer recommendations and shall operate within manufacturers specified operating conditions at all times; and • Flow meters must be calibrated according to manufacturer specifications and shall be checked and calibrated at regular intervals according to these specifications.
Volume of fossil fuels combusted (liquid or solid)	L, m^3 or other	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	MWh	Continuous measurement of electricity consumption or reconciliation of maximum power rating for each type of equipment and operating hours.	• 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.
Incremental, Directly Connected Electricity	MWh	Continuous measurement of electricity generation or reconciliation of maximum power rating for each type of equipment and operating hours	Incremental electricity must meet the following three criteria: • Direct Connection: the electricity source is directly connected to the site or through a recognized Industrial System Designation (ISD); • Dedicated Electricity Contract: the electricity is sourced using a dedicated electricity purchase agreement; and • New or Unused Generating Capacity: the electricity results from incremental

			electricity generating capacity that was not previously being utilized. This includes either newly installed capacity or capacity that has not been utilized in the average hour over the three year period prior to, and ending within 6 months of project initiation. To determine unused generating capacity: ○ Calculate the hourly unused nameplate capacity of the electricity generating unit (nameplate capacity minus electricity production) for each hour over the three year period; and ○ Take the average of the hourly unused nameplate capacities from (1) over the three year period as the unused electricity capacity.
Incremental Heat	GJ	Continuous measurement of heat generation or reconciliation of maximum capacity rating for each type of equipment and operating hours.	Incremental heat, including steam, sourced for the project must be from either newly installed heat generating capacity, or capacity that has not been utilized over the three year period prior to, and ending within 6 months of project initiation.

5.1.3 Monitoring, Measurement and Verification of Containment

Each carbon capture and storage project must undertake monitoring activities to ensure the safe and permanent storage of CO_2 in accordance with the facility's operating license requirements. Monitoring requirements are based on the characteristics of the deep saline aquifer. Relevant regulations are discussed below. It is the responsibility of the project developer to stay up to date with evolving regulatory requirements.

The monitoring, measurement and verification plan must be submitted as part of the tenure application under the *Mines and Minerals Act*, as amended by the *Carbon Capture and Storage Statutes Amendment Act*. The following directives specify specific requirements for measurements and monitoring:

1. Directives 007 and 017: requirements for measuring and reporting the amounts of acid gas injected;
2. Directive 020: minimum requirements for well abandonment, testing to detect leakage and mitigation measures in the event of detecting leakage;
3. Directive 051: classifies disposal wells according to the injected or disposed fluid, and specifies design, operating and monitoring requirements for each class of well; and
4. Directive 065: addresses enhanced hydrocarbon recovery, natural gas storage, and acid gas disposal including requirements to ensure confinement of the disposed fluid, isolation of disposed fluids, and that disposal does not affect other hydrocarbon reservoirs. Note: CO_2 is an acid gas. As such, Directive 065 applies to carbon capture and storage schemes.

The measurement, monitoring, and verification plan must be specific to the storage complex that CO_2 is being injected into, to ensure there are no emissions from the subsurface to the atmosphere.

The developer must demonstrate that a measurement, monitoring and verification plan has been prepared and approved in accordance with Alberta Energy Regulator requirements. The developer must also confirm that the project continues to operate in accordance with the conditions outlined in the operating license. The developer must also demonstrate that the measurement, monitoring and verification plan has been updated as required by the Alberta Energy Regulator.

Monitoring, measurement and verification requirements apply to the following four project phases of the carbon capture and storage project:

1. Pre-Injection: characterize risks, identify monitoring tasks, evaluate and select monitoring approach, and acquire baseline data;
2. Injection: monitor activities to manage containment risk and storage performance and update as needed to ensure continued effectiveness;
3. Closure: monitor to manage containment risk and to demonstrate storage performance is consistent with expectations for permanent storage; and
4. Post-Closure: transfer monitoring requirements to the Government of Alberta to ensure the captured carbon dioxide is behaving in a stable and predictable manner, with no significant risk of future leakage.

In summary, the monitoring, measurement and verification program will include both baseline monitoring tasks that are to be conducted during the pre-injection phase of the project and complementary operational monitoring tasks to be conducted periodically during the injection phase. Monitoring will be maintained during the closure phase after injection has ceased. The specific monitoring technologies and activities will be determined and continuously updated and refined based on the site-specific experience gained during the baseline and operational phases of the project as approved by Alberta Energy and the Alberta Energy Regulator to ensure CO_2 remains permanently stored in the deep saline aquifer.

5.2 Project Documentation

Minimum record requirements are:

Project Eligibility
Documentation for project eligibility includes:

- The name, contact information, and statement of qualification of the project developer(s);
- Evidence of the project start date;
- Evidence of ownership to credits generated;
- All applicable permits for project condition;
- Evidence that the project results in real emission reductions located in Alberta including legal land location or GPS coordinates of the capture facility and injection wells;
- A suitable measurement, monitoring, and verification plan; and
- Project quantification documentation

Baseline Documentation
Documentation for the baseline condition includes:

- Justification for changes from the included or excluded sources and sinks from those listed in Table 5;
- For each project year, the total emissions accounted under each included baseline sources/sinks listed in Table 5, and included in the baseline by the project developer;
- For each project year, calculations applied to measured baseline data and justifications for any deviations from those calculations described in Table 6 and Table 7; and
- For each project year, the measured baseline data as recorded from the measurement device before calculations are applied.

Project Documentation
Documentation for the project condition includes:

- Justification for changes from the included or excluded project sources/sinks from those listed in Table 5;
- For each project year, the total emissions accounted under each included project sources and sinks as listed in Table 5 and included in the project by the project developer;
- For each project year, calculations applied to measured project data and justifications for any deviations from those calculations described in Table 6 and Table 7 ; and
- For each project year, the measured project data as recorded from the measurement device, before calculations are applied.

5.3 Record Keeping

Alberta Environment and Parks requires that project developers maintain appropriate supporting information for the project, including all raw data for the project for a period of seven years after the end of the project crediting period. Where the project developer is different from the person implementing the activity, as in the case of an aggregated project, the individual projects and the aggregator, must both maintain sufficient records to support the offset project. The information listed below must be collected and disclosed to the third party verifier and/or government auditor upon request.

Record Keeping Requirements:

- Raw baseline period energy, and biomass management data, independent variable data, and static factors within the measurement boundary;
- A record of all adjustments made to raw baseline data with justifications;

- All analysis of baseline data used to create mathematical model(s);
- All data and analysis used to support estimates and factors used for quantification;
- Expected end of life date of equipment removed or renovated under the project;
- Common practices relating to possible greenhouse gas reduction scenarios discussed in this protocol (such as biomass management practices);
- Metering equipment specifications (model number, serial number, manufacturer's calibration procedures);
- 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; and
- Initial and annual verification records and audit results.

In order to support the third party verification and the potential supplemental government audit, the project developer must put in place a system that meets the following criteria:
- All records must be kept in areas that are easily located;
- All records must be legible, dated and revised as needed;
- All records must be maintained in an orderly manner;
- All documents must be retained for seven years after the project crediting period;
- Electronic and paper documentation are both satisfactory; and
- Copies of records should be stored in two locations to prevent loss of data.

Attestations are not considered sufficient proof that an activity took place and do not meet verification requirements.

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 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 greenhouse gas reductions;
- 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;

- Protecting records of data and documentation by keeping both a hard and soft copy of all documents;
- Recording and explaining any adjustment made to raw data in the associated report and files; and
- Developing a contingency plan for potential data loss.

5.5 Liability

Offset projects must be implemented according to the approved protocol and in accordance with government regulations. Alberta Environment and Parks reserves the right to audit Offset Credits and associated projects submitted to the Department for compliance under the Specified Gas Emitters Regulation and may request corrections based on audit findings.

The project developer retains liability for the carbon capture and storage project and sequestered carbon until a closure certificate is issued by Alberta Energy or the Alberta Energy Regulator. Once a closure certificate has been issued, liability for events resulting from these activities is transferred from the project developer to the Government of Alberta according to terms as detailed in the relevant legislation and regulations.

The project developer retains liability for all climate obligations resulting from activities and events occurring during project execution and the closure period prior to issuance of the closure certificate. The Government of Alberta is developing policy guidelines on climate CO_2 liability for the post closure period and will update the regulation and protocol, as required.

Reversals

A reversal is described as an accidental or intentional release or removal of injected CO_2 from the deep saline aquifer. Sources and sinks quantification methods in this protocol also provide mechanisms to quantify reversals (see Table 6) and Appendix B provides a method for accounting for uncertainty arising out of the measurement, monitoring and verification plan. Reversals after the project crediting period must be trued up prior to approval of closure certificate[9].

Under with the *Mines and Minerals Act* and the Carbon Sequestration Tenure Regulation as issued by the Government of Alberta, carbon sequestration lease holders are required to: 1) submit and receive approval of an MMV Plan that identifies all activities needed to demonstrate containment of the injected CO_2; 2) comply with the MMV Plan as approved; 3) provide an annual report on the outcome of the MMV activities; 4) submit an update of the MMV Plan every three years; and 5) submit an update of the MMV Plan every 15 years upon application for lease renewal. If at the time of quantification and verification of offset credits the CCS operator is not able to demonstrate via the most recent annual report from the MMV program that the full volumes of injected CO_2 remain in the geology, it will be assumed that there is an emission from subsurface to atmosphere. In this case, the volume of the emission from subsurface will be quantified by an engineering estimate to determine the reversal volume, via project quantification term P20 and Appendix B.

[9] CCS Summary Report of the Regulatory Framework Assesment, Alberta Energy, 2013, Recommendation 52: If any CO_2 is produced and/or released that was injected under a carbon sequestration lease, it must be accounted for and reported, and previously earned emissions reduction credits must be reconciled and/or properly accounded for under any other potential future provincial climate change policies.

6.0 References

Alberta Energy Regulator (formerly Energy Resources Conservation Board). Directive 007 Volumetric and Infrastructure Requirements. September 2011.
Alberta Energy Regulator. Directive 017 Measurement Requirements for Oil and Gas Operations. May 2013.

Alberta Energy Regulator. Directive 020 Well Abandonment. June 2010.

Alberta Energy Regulator. Directive 051 Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements. March 1994.

Alberta Energy Regulator. Directive 065 Resources Applications for Oil and Gas Reservoirs. April 2014.

Alberta Environment and Parks (formerly Alberta Environment and Sustainable Resource Development). Alberta Offset System Quantification Protocol for Enhanced Oil Recovery. Version 1. October 2007.

American Carbon Registry. Blue Source's Emission Reduction Protocol for Merit Energy's CO_2 Geologic Sequestration through Enhanced Oil Recovery Operations. July 2008.

American Carbon Registry. Greenhouse Gas Emission Reduction Protocol for the Monell Enhanced Oil Recovery Project, Anadarko Petroleum Corporation. Revision 3. August 2004.

American Carbon Registry. Blue Source's Greenhouse Gas Emission Reduction Protocol for Petro Source's Capture of Vent-Stack CO_2 in Combination with Enhanced Oil Recovery Operations. December 2006.

American Carbon Registry. Greenhouse Gas Emission Reduction Protocol for the Salt Creek Enhanced Oil Recovery Project Howell Petroleum Corporation. Revision 4. August 2004.

American Carbon Registry. Blue Source's Greenhouse Gas Emission Reduction Protocol for SandRidge CO_2 LLC's capture of Vent-Stack CO_2 at Pikes Peak in Combination with Enhanced Oil Recovery Operations. December 2008.

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

Canadian Standards Association. GHG Reductions Registry. Offset Project Plan CO_2 Capture from Prentiss1 for EOR MEGlobal Canada Inc. January 2009.

Canadian Standards Association. GHG Reductions Registry. Offset Project Plan CO_2 Capture from Prentiss2 for EOR MEGlobal Canada Inc. January 2009.

Canadian Standards Association. GHG Reductions Registry. Protocol for Tracking Greenhouse Gas Emission Reductions from the Hays Enhanced Oil Recovery Project. Anadarko Canada Resources. December 2005.

Canadian Standards Association. GHG Reductions Registry. Verification of Blue Source Emission Reduction Credits Created from Denbury Resources' Geologic Sequestration Project. Denbury Resources. April 2004.

Canadian Standards Association. Z741 Geological Storage of Carbon Dioxide. December 2012.

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

Environment Canada. National Inventory Report Fuel Combustion Emission Factors. 2011.

International Standards Organization. ISO 14064-2:2006 Specification with Guidance at the Project Level for Quantification, Monitoring and Reporting of GHG Emission Reductions and Removal Enhancements. 2006.

United States Environmental Protection Agency. Proposed Rule Subpart RR–Carbon Dioxide Injection and Geologic Sequestration. March 2010.

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

World Resources Institute and the World Business Council Development. Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard (Revised Edition). March 2004.

World Resources Institute. 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 Developers

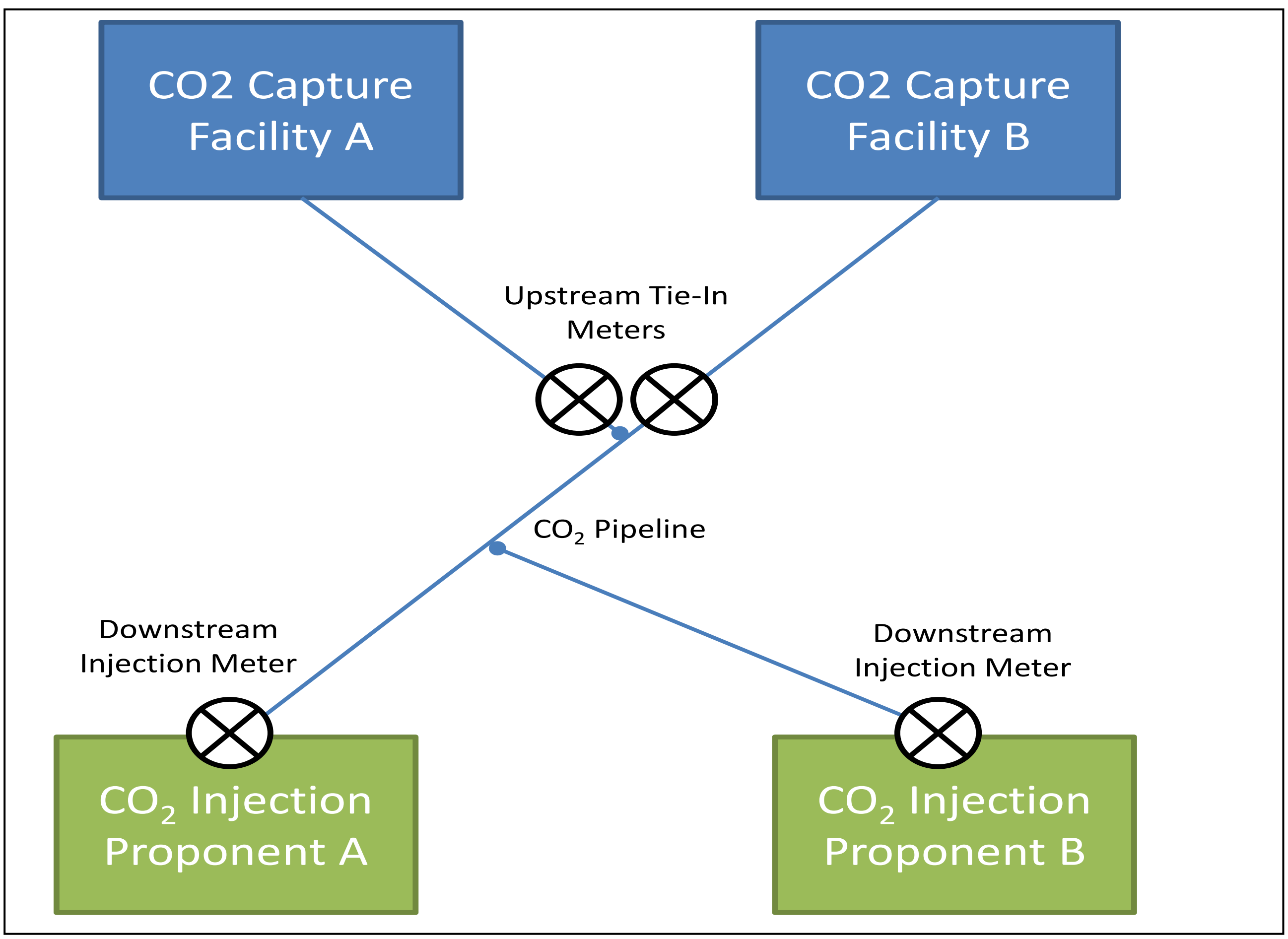
The following provides guidance for projects in which the CO_2 is being transported to carbon capture and storage activities and third party injection activities (enhanced oil recovery, or permanent storage).

Project developers must demonstrate that all sources and sinks are properly accounted for and must ensure all project 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 to prorate emissions proportionally across the network. The project developers must provide justification for the method and values used to determine the system emission factor used.

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 and refer to Sources/Sinks P3-P11. Figure A1 provides a schematic to illustrate the process flow for injection of CO_2 by multiple developers.

Figure A1: Metering Diagram for the Injection of CO_2 by Multiple Developers



To properly account for all project emissions, project developers must proportionally attribute all project emissions prior to the tie-in point across all developers. Each developer must deduct the associated emissions proportional to the amount of CO_2 received from their total emission reduction. This results in an equal distribution of the associated project emissions prior to the tie-in point depending on the amount 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 deducts 60% of the project emissions prior to the tie in pointfrom Developer A's total emission reductions. Developer B deducts 40% of the project emissions prior to the tie in point from Developer B's total emission reductions.

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 of their individual project emissions associated with CO_2 injection.

Appendix B: Guidance for Estimating Emissions from Subsurface Equipment and Deep Saline Aquifers

For the quantification of P-20 Emission from Subsurface to Atmosphere, the quantity of emissions leaked from the subsurface equipment or deep saline aquifer to atmosphere for each of the leakage events must be estimated with a maximum overall uncertainty of ±7.5% over the reporting period using the absolute value of the uncertainly. 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:

$$CO_{2,\ Reported}\ [t\ CO_2] = CO_{2,\ Quantified}\ [t\ CO_2] * (1 + (Uncertainty_{\ System}\ [\%]/100))$$

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 even 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 two sources: 1) International Energy Agency presentation on Monitoring and Reporting Guidelines for Injection and Storage[10]; and 2) Clean Development Mechanism United Nations Framework Convention on Climate Change[11].

[10] International Energy Agency, presentation on Monitoring and Reporting Guidelines for Injection and Storage, January 2014, which states: "Maximum ±7.5% uncertainty, if exceeded then add 'uncertainty Adjustment'"

[11] Implications of the Inclusion of Geological Carbon Dioxide Capture and Storage as CDM Project Activities Draft Final Report - Annex 1 Proposed Agenda - Annotations pp 44, Clean Development Mechanism of The United Nations Framework Convention on Climate Change, 2009