

DRAFT QUANTIFICATION PROTOCOL FOR THE CAPTURE OF CO₂ AND STORAGE IN DEEP SALINE AQUIFERS

PUBLIC COMMENT DRAFT Version

December 2011

Government
of Alberta ■

Alberta ■

1.0 Offset Project Description

This quantification protocol is written for project developers familiar with carbon capture and storage processes applied to industrial facilities. The opportunity for generating carbon offsets with this protocol arises from the direct disposal of CO₂ from a previous source of emissions, into deep saline aquifers.

A typical carbon capture and storage project applicable to this protocol consists of three main components:

- CO₂ capture infrastructure, which involves a process modification to an industrial facility. The carbon capture facility in this protocol is separate from the industrial facilities which operate the primary process, such as steam methane reforming for hydrogen production. The carbon capture facility applies a CO₂ capture technology that uses a chemical solvent.
- A CO₂ pipeline to transport CO₂ from the capture facility to the injection well(s).
- Disposal of CO₂ through injection wells and into deep saline aquifers.

1.1 Protocol Scope

This protocol scope covers the full carbon capture and storage chain from capture through compression, transport, injection and storage. The source of CO₂ is from an industrial facility that operates a primary process, and the carbon capture facility applies a capture technology that uses chemical solvents. Refer to Figure 3 for a generic project process flow diagram. Additional information on the development of this protocol is available in the technical seed document, posted on the Government of Alberta's Climate Change Central website.

Baseline Condition for Capture of CO₂ and Disposal in Deep Saline Aquifers:

The baseline condition is quantified by the metered quantity of CO₂ that is captured and injected into the deep saline aquifer for permanent storage. These volumes of CO₂ would normally have been emitted to the atmosphere. The quantification approach used in the protocol is based on the direct measurement of the quantity of CO₂ that has been captured and injected into the deep saline aquifer.

Project Condition for Capture of CO₂ and Disposal in Deep Saline Aquifers:

The project condition is quantified by aggregating all associated greenhouse gas emissions resulting from the energy inputs required to capture, compress, transport, and inject the CO₂, such that these emissions can be deducted from the baseline condition to determine the net greenhouse gas reduction at the project level.

The implementation of carbon capture and storage projects will primarily reduce carbon dioxide emissions; however, three types of greenhouse gas emissions are quantified in the project condition (e.g. combustion emissions), namely carbon dioxide, methane, and nitrous oxide emissions, as shown in Table 1.

1 **Table 1: Relevant Greenhouse Gases Applicable to Carbon Capture and Storage Projects**

Specified Gas	Formula	100-year GWP ¹	Applicable to Project
Carbon Dioxide	CO ₂	1	✓
Methane	CH ₄	21	✓
Nitrous Oxide	N ₂ O	310	✓
Sulphur Hexafluoride	SF ₆	23,900	×
Perfluorocarbons*	PFCs	Variable	×
Hydrofluorocarbons*	HFCs	Variable	×

2
3
4 * A complete list of perfluorocarbons and hydrofluorocarbons regulated under the *Specified Gas Emitters Regulation* is available in Technical Guidance for Offset Project Developers.

5 **1.2 Protocol Applicability**

6 The following requirements must be met to confirm eligibility under the Alberta Offset
7 System.

- 8
9 1. The Project captures CO₂ directly from industrial facilities whereby:
- 10 - All relevant sources and sinks associated with the project are accounted
 - 11 for; and
 - 12 - The project configuration must match the sources and sinks included in
 - 13 Figure 3.
- 14
- 15 2. The Project is applicable to injection in deep saline aquifers capable of
- 16 permanently storing CO₂ emissions. For each specific project, the applicant must
- 17 have both:
- 18 - Approved Carbon Sequestration Lease(s) in accordance with the *Mines*
 - 19 *and Minerals Act* and the *Carbon Sequestration Tenure Regulation* as
 - 20 issued by the Government of Alberta²; and
 - 21 - Approval for a CO₂ Storage Scheme as per application and approval under
 - 22 the Energy Resources Conservation Board, Directive 065, Unit 4³

23
24 This protocol is not applicable to either enhanced oil recovery activities or to acid
25 gas injection schemes associated with sour natural gas processing operations.
26 Proponents with CO₂ enhanced oil recovery projects or acid gas injection projects

¹ **Global warming potential** or GWP is the relative measure of the warming effect that the emission of a specified gas might have on the Earth's atmosphere calculated as the ratio of the time-integrated radiative forcing that would result from the emission of one kilogram of a given specified gas to that from the emission of one kilogram of carbon dioxide (source: Government of Alberta, Specified Gas Reporting Standard – March 2011: <http://environment.gov.ab.ca/info/library/7759.pdf>).

² Carbon Sequestration Tenure Regulation, Alberta Regulation 68/2011, Mines and Minerals Act, http://www.gp.alberta.ca/documents/orders/orders_in_council/2011/411/2011_179.html

³ Directive 065, The Energy Resources Conservation Board, August 2010, <http://www.ercb.ca/docs/documents/directives/Directive065.pdf>

- 1 should refer to the applicable Alberta Offset System quantification protocols for
2 those activities.
- 3 3. The Project must be in compliance with all operating permits and relevant
4 regulations in Alberta.
- 5 4. The quantification of reductions achieved by the project is based on actual
6 measurement and monitoring (except where indicated in this protocol) as
7 indicated by the proper application of this protocol.
- 8 5. Metering of injected gas volumes takes place as close to the injection point as is
9 reasonable to address the potential for fugitive emissions as demonstrated by
10 Figure 3.
- 11 6. The project meets the eligibility criteria stated in section 7.0 of the *Specified Gas*
12 *Emitters Regulation*. In order to qualify, emission reductions must:
- 13 - Occur in Alberta;
 - 14 - Result from actions not otherwise required by law;
 - 15 - Result from actions taken on or after January 1, 2012
 - 16 - Be real, demonstrable, quantifiable;
 - 17 - Have clearly established ownership including, if applicable, appropriate
18 documented transfers of ownership from the land owner to land lessee;
 - 19 - Be counted once for compliance; and
 - 20 - Be implemented according to ministerial guidelines.

21 ***1.3 Protocol Flexibility***

22 The following flexibility mechanism may be used. It is the responsibility of project
23 developers to justify the rationale for using the flexibility mechanism.

- 24
- 25 1. Greenhouse gases may be sequestered by multiple proponents. Projects in which
26 the CO₂ is being transported to carbon capture and storage activities as well as
27 third party injection activities (enhanced oil recovery or disposal activities) must
28 demonstrate that all project emission sources and sinks are properly accounted. In
29 the case of a complex CO₂ system or network, the emissions from that network
30 would have to be accounted for in the project condition. A system emission factor
31 may be applied whereby the project emissions are prorated proportionally across
32 each project proponents participating in the network. The proponents would have
33 to justify the method and values used to determine the system emission factor
34 during the project, and could initiate a protocol review by Alberta Environment.
35 Please refer to Appendix C for guidance.

36 ***1.4 Glossary of New Terms***

Carbon Capture and Storage Facilities: Carbon capture and storage facilities are broadly defined to include all infrastructure required to capture, compress,

transport, inject and store CO₂.

Carbon Sequestration Tenure Regulation	The carbon sequestration tenure regulation (April 28 2011) under the <i>Mines and Minerals Act</i> establishes the process to apply for pore space tenure. The ERCB sets out several administrative details and processes such as requiring permit and lease holders to determine storage site suitability as well as submit monitoring, measurement and verification plans.
Chemical Solvent Capture	Chemical solvent capture is an absorption process whereby a substance is incorporated into another of a different state (gases being absorbed by a liquid).
Deep Saline Aquifer	Deep saline aquifers are porous rock formations at least 1000 meters underground that contain water and high salt and/or mineral content. Deep saline aquifers display trapping mechanisms suitable for effective permanent storage of injected CO ₂ .
Disposal	The elimination of waste gases as it pertains to the ERCB Directive 065.
ERCB Directives	<p>The Energy Resources Conservation Board (ERCB) is an independent, quasi-judicial agency of the Government of Alberta. The ERCB regulates the safe, responsible, and efficient development of Alberta's energy resources: oil, natural gas, oil sands, coal, and pipelines. The mission statement of the ERCB is to ensure that the discovery, development and delivery of Alberta's energy resources takes place in a manner that is fair, responsible and in the public interest. Directives are documents setting out new or amended ERCB requirements or processes to be implemented and followed by licensees, permittees, and other approval holders under the jurisdiction of the ERCB.</p> <ul style="list-style-type: none">• Directive 007 – Volumetric and Infrastructure Requirements (September 20 2011) - This directive sets out ERCB 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 18 2011) – This

directive consolidates, clarifies, and updates ERCB requirements for measurement points used for ERCB 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 ERCB (which are included in other ERCB documents, such as Directive 007: Volumetric and Infrastructure requirements).

- Directive 020 – Well Abandonment (June 9 2010) – This directive details the minimum requirements for abandonments, casing removal, zonal abandonments, and plug backs as required under Sections 3.013 of the Oil and Gas Conservation Regulations.
- Directive 051 - Injection and Disposal Wells: Well Classifications, Completion, Logging, and Testing Requirements (March 1994) – This directive classifies injection and disposal wells according to the injected or disposed fluid and specifies design, operating, and monitoring requirements for each class of well.
- Directive 065 - Resources Applications for Oil and Gas Reservoirs (October 6 2011) - details the process to apply to the ERCB for all necessary approvals to establish the strategy and plan to deplete a pool or portion of a pool using one resource application.

Industrial Facility

An industrial facility is one that produces anthropogenic greenhouse gas emissions resulting from a primary process.

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.⁴

Primary Process

The primary process includes any type of process that

⁴ Guidelines for Carbon Dioxide Capture, Transport, and Storage. 2008. World Resources Institute.

manufactures a primary product, such as hydrogen for bitumen upgrading.

Primary Product

The primary product is the core product manufactured by the primary process and is used to determine functional equivalency. For processes such as steam methane reforming, hydrogen is the primary product.

Steam Methane Reforming

Steam methane reforming is the most common process by which hydrogen is produced. Heated methane and steam are brought into contact with a catalyst, which produces H₂, CO₂, carbon monoxide (CO), and other trace compounds. The CO is further reacted with steam in a shift reactor to produce H₂ and CO₂. The CO₂ and H₂ are then separated using pressure swing adsorption units, membranes or absorption columns to generate pure hydrogen.

1
2

2.0 Baseline Condition

The protocol uses a **projection-based** baseline condition. Under this scenario, baseline emissions are quantified using direct measurements of the quantity of CO₂ that has been injected and stored in the project condition. The baseline condition is dynamic in approach as the quantity of CO₂ captured and injected will vary from year to year based on the on-stream availability of the hydrogen production units and the demand for hydrogen at the hydrogen-consuming processes. The use of direct measurements to represent the baseline provides a high level of accuracy.

The baseline scenario for this protocol is the continued practice of emitting CO₂ to the atmosphere from industrial facilities operating a primary process, such as steam methane reforming for hydrogen production. The baseline emissions are quantified from the metered quantity of CO₂ that is injected and stored into the deep saline aquifer for permanent storage 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 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.

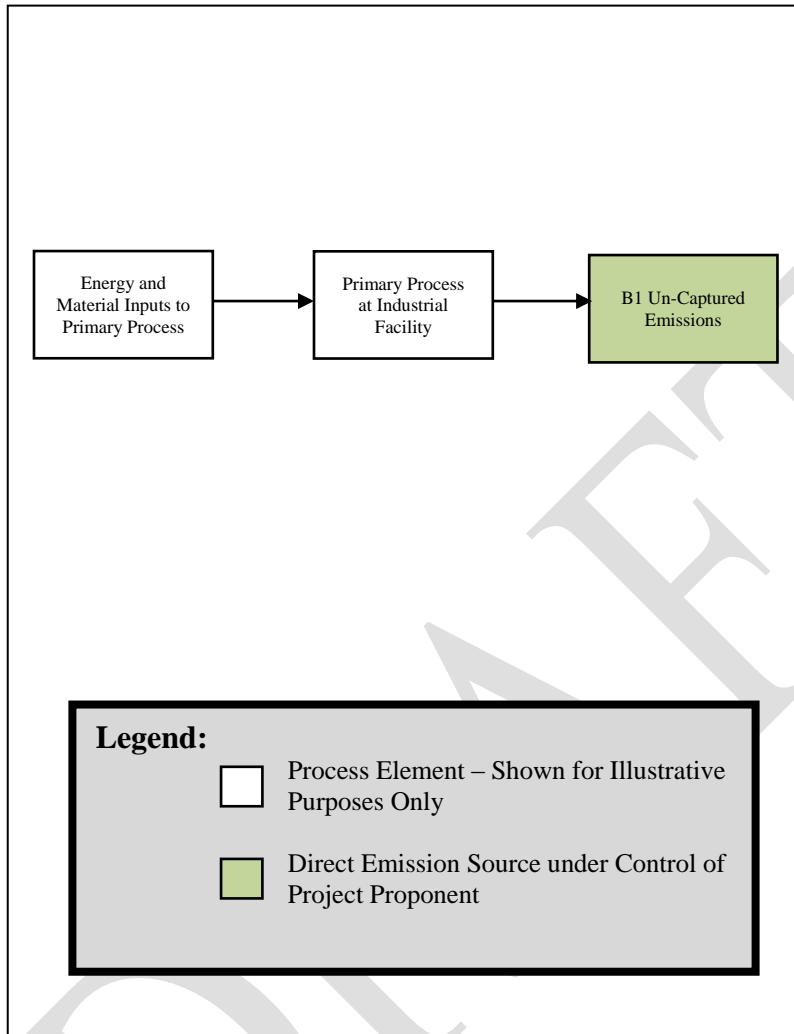
Related: A related source and/or sink has material and/or energy flows into, out of, or within a project but is not under the reasonable control of the project developer.

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

1 **Figure 1: Process Flow Diagram for the Baseline Condition**

2
3
4

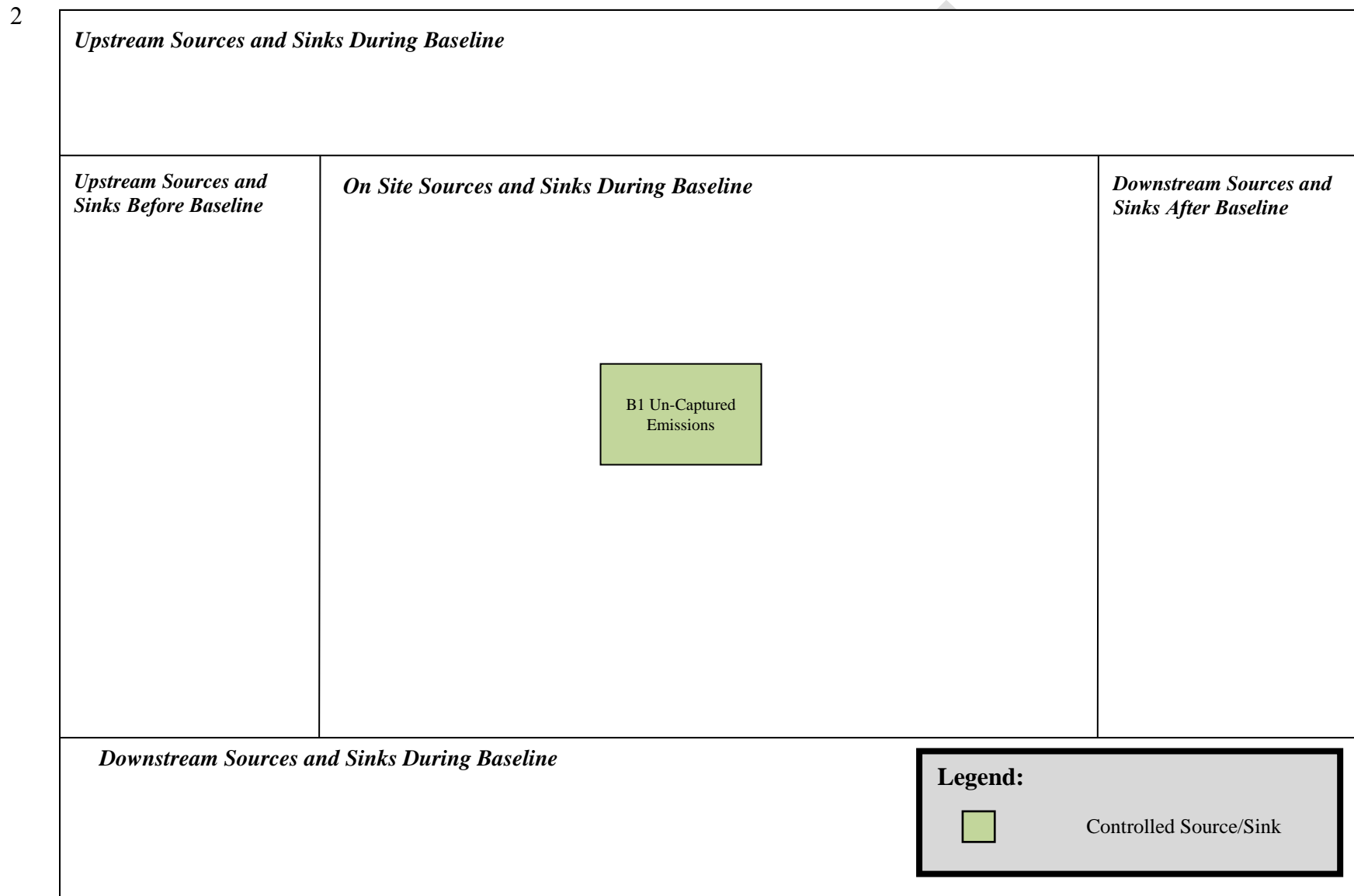


1 **Table 2: Baseline Process Elements**

1. Process Elements	2. Description
Energy and Material Inputs to Primary Process	The primary process (e.g. steam methane reforming for hydrogen production) will require energy inputs such as electricity, heat, and fossil fuels which may be supplied from on- or off-site sources. Material inputs are required to produce the primary product. The quantities of each energy input should be tracked in kWh or kJ and material inputs in kg or m ³ .
Primary Process at Industrial Facility	The primary process is the sum of the activities that are undertaken by an industrial facility to produce the primary product. The primary process includes any type of process that manufactures a primary product, such as steam methane reforming for hydrogen production intended for bitumen upgrading.

DRAFT

1 **Figure 2: Baseline Sources and Sinks**



1 **Table 3: Baseline Condition Sources and Sinks**

1. Source/Sink	2. Description	3. Controlled, Affected, Related
Upstream Sources and Sinks Before Project		
N/A		
Upstream Sources and Sinks During Project		
N/A		
On-Site Sources and Sinks During Project		
B1 Un-Captured Emissions	All industrial facility emissions related to the primary process (e.g. steam methane reforming process) are emitted to the atmosphere in baseline. Baseline emissions are quantified using direct measurements of the quantity of CO ₂ that has been captured and stored in the project condition. These emissions are a portion of the total emissions from the industrial facility.	Controlled
Downstream Sources and Sinks During Project		
N/A		
Downstream Sources and Sinks After Project		
N/A		

2

DRAFT

3.0 Project Condition

Carbon capture and storage projects under this protocol consist of three distinct components, namely the capture and compression of CO₂, the transport of CO₂ to the injection wells, and the metering and disposal of CO₂ 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 CO₂ capture, transport and disposal technologies and processes and are not precluded from applying this protocol.

Capture

CO₂ capture refers to the separation of CO₂ from the other components in a primary process gas stream of an industrial facility. The CO₂ capture infrastructure may consist of the following main process blocks:

- CO₂ capture technology using chemical solvent, as an example this typically includes amine solvents, absorbers and associated equipment.
- Solvent regeneration unit(s), which may include the following:
 - The stripper column and associated reboiler, pumps and heat exchangers
 - Solvent filtration
 - Solvent storage
 - The CO₂ vent stack
- CO₂ compression, which may include a multi-stage compressor with an electrical motor and interstage coolers and knockout drums
- CO₂ dehydration, which may include a triethylene glycol (TEG) absorber and regeneration unit

The absorbers typically use an amine solvent to capture the CO₂ from the primary process gas stream of an industrial facility (ie. steam methane reforming for hydrogen production). The primary process gas stream enters an absorption column that contains the chemical solvent solution. As the gas stream contacts the solvent in the absorption column, the CO₂ is absorbed into the solution. The gas stream then exits the stack, and the solution is sent to a stripping column, where the CO₂ is removed from the solution through an increase in the solution temperature. The solvent is recycled and sent to the absorption tower, while the CO₂ is cooled, dried, and compressed to a dense phase fluid. All emissions associated with the capture process are to be accounted for under the project condition.

Transport

The CO₂ transportation infrastructure for projects under this protocol includes 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 may be used to collect, transmit data from the pipeline to a control centre and monitor line break valves. CO₂ is typically transferred in dense phase

1 and emissions arising from the compression and pumping of CO₂ at the capture site as
2 part of the transport system are accounted for in the project condition.

3 4 ***Storage in Deep Saline Aquifers***

5 Injected carbon dioxide is trapped within the pore spaces of the deep saline aquifer,
6 dissolved in formation fluids, and may eventually be mineralized (over long time
7 periods).⁴ Most geologic storage options, with the exception of adsorption, are most
8 efficient at depths greater than 1000 metres as the formation pressure and temperature
9 causes CO₂ to remain in a dense state. There are five general trapping mechanisms by
10 which carbon dioxide is stored⁵:

- 11
- 12 1) Physical or volumetric trapping below an impermeable, confining layer (caprock).
- 13 2) Capillary or residual trapping (retention in an immobile phase, trapped in the pore
14 spaces of the storage complex);
- 15 3) Mineral trapping or mineralization (precipitation as a carbonate material);
- 16 4) Solubility trapping (dissolution of CO₂ in solution in the formation fluids that
17 saturate the pore space within a rock formation);
- 18 5) Adsorption onto organic matter in coal and shale (i.e. CO₂ bonds with formation
19 rocks).
- 20

21 All emissions associated with disposal operations, including vented and fugitive
22 emissions at the injection site (after the injection volume meter) and from the subsurface,
23 are accounted for in the project condition. With appropriate site selection, good operating
24 practices and various monitoring activities (refer to Section 5.0), it is anticipated that
25 there will be no CO₂ emissions from the subsurface to atmosphere.
26

⁵ Part II: Carbon Capture and Geological Storage. June 2007. IPIECA & API.

1 **3.1 Identification of Project Sources and Sinks**

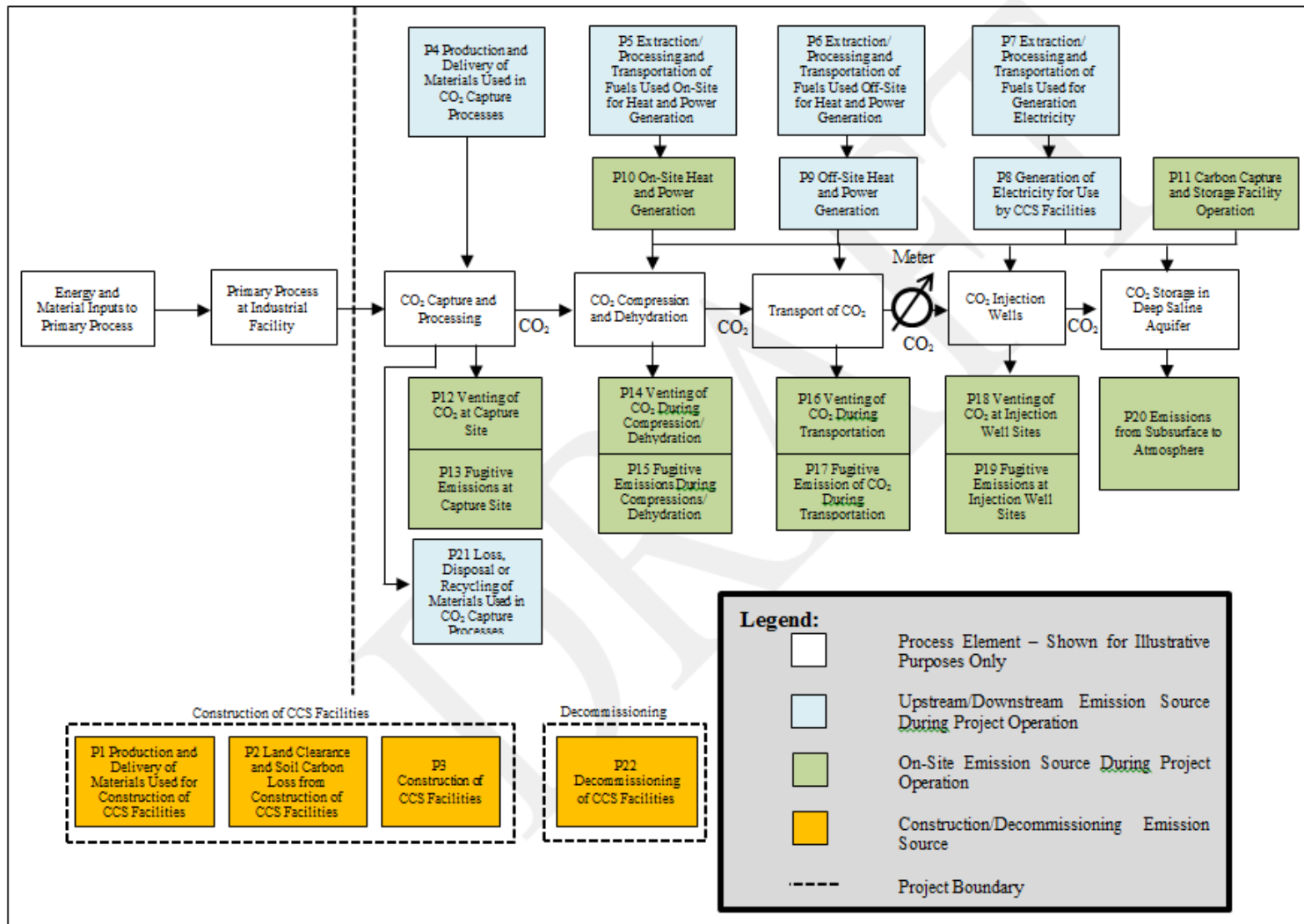
2 Sources and/or sinks for the project condition were identified based on review of existing
3 best practice guidance contained in relevant greenhouse gas quantification protocols and
4 carbon capture and storage project configurations. This process confirmed that sources
5 and/or sinks in the process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

7
8 These sources and/or sinks have been further refined according to the lifecycle categories
9 identified in Figure 3. These sources and/or sinks were further classified as controlled,
10 related, or affected as described in **Figure 4** below.

11
12

DRAFT

1 **Figure 3: Process Flow Diagram for the Project Condition**



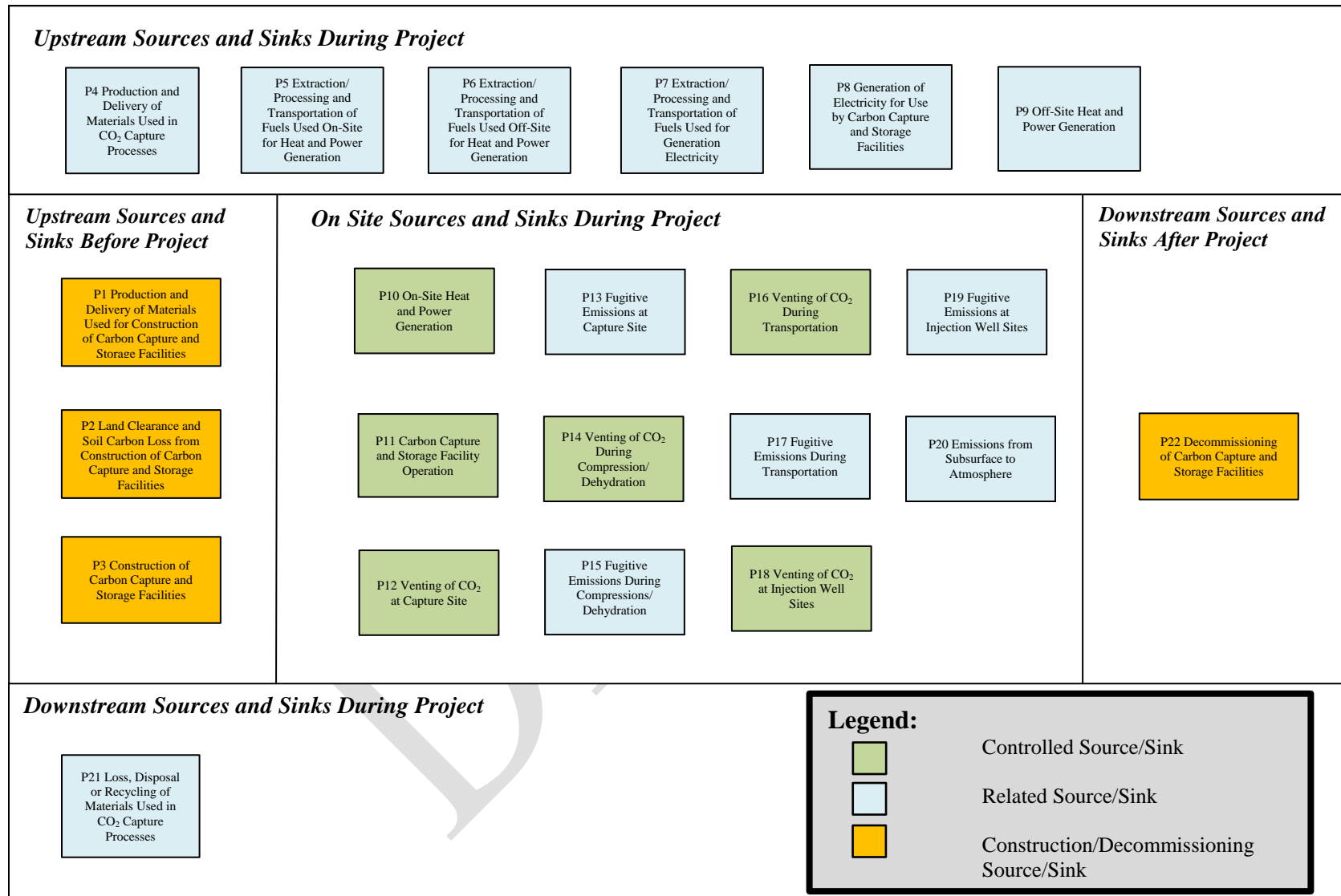
2

1 **Table 4: Project Process Elements**

1. Process Elements	2. Description
Energy and Material Inputs to Primary Process	The primary process (e.g. steam methane reforming for hydrogen production) will require energy inputs such as electricity, heat, and fossil fuels which may be supplied from on- or off-site sources. Material inputs are required to produce the primary product. The quantities of each energy input should be tracked in kWh or kJ and material inputs in kg or m ³ .
Primary Process	The primary process is the sum of the activities that are undertaken by an industrial facility to produce the primary product. The primary process includes any type of process that manufactures a primary product, such as steam methane reforming for hydrogen production intended for bitumen upgrading.
CO ₂ Capture and Processing	The CO ₂ rich stream coming from the industrial facility will need further purifying and processing before it can be injected. The capture technology applied at the capture facility uses chemical solvent such as amine regeneration. The source and quantity of any material, heat, or electricity inputs to the CO ₂ capture process should be tracked.
CO ₂ Compression and Dehydration	Before transportation, the CO ₂ will need to be compressed. In addition, dehydration may be required to prevent hydrate formation. This may be achieved through heating or other processes. The volume and quantity of fossil fuels and/or the quantity of electricity consumed should be tracked for the compressor(s) and dehydration unit(s).
Transport of CO ₂	CO ₂ will be transported via pipeline to the injection site. Depending on the length of the pipeline, additional compression may be needed. The volume and quantity of fossil fuels and/or the quantity of electricity consumed should be tracked for any additional compression.
CO ₂ Injection Wells	CO ₂ 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. The volume and quantity of fossil fuels and/or the quantity of electricity consumed should be tracked.
CO ₂ Storage in Deep Saline Aquifers	CO ₂ will be disposed in deep saline aquifers suitable for permanent storage of injected CO ₂ .

2
3

1 **Figure 4: Project Condition Sources and Sink**
2



1 **Table 5: Project Condition Sources and Sinks**

1. Source/Sink	2. Description	3. Controlled, Affected, Related
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
P2 Land Clearance 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. The carbon content of all soil types and area cleared for construction are important characteristics to be tracked.	Related
P3 Construction of Carbon Capture and Storage Facilities	The process of construction at the site will require a variety of heavy equipment, smaller power tools, cranes and generators. The operation of this equipment will have associated greenhouse gas emission from the use of fossil fuels and electricity.	Related
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 house gas emissions are attributed to the fossil fuel consumption for transport of these materials and electricity and fossil fuel inputs for their production. The total aggregate quantity of each chemical delivered to the site should be tracked.	Related
P5 Extraction/Processing and Transportation of Fuels Used On-Site for Heat and Power Generation	The fuels used for heat and power 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 ₂ O emissions are associated with these activities. Volumes and types of fuels are important processes to be tracked.	Related
P6 Extraction/Processing and Transportation of Fuels Used Off-Site for Heat and Power Generation	The fuels used for heat and power 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 ₂ O emissions are associated with these activities. Volumes and types of fuels are important processes to be tracked.	Related
P7 Extraction/Processing and Transportation of Fuels Used for Generation of Grid Electricity	The fuels used for the generation of grid electricity will need to be extracted, processed, and delivered to the generating stations. Delivery may include shipments by truck, rail or pipeline. CO ₂ , CH ₄ , and N ₂ O emissions are associated with these activities. The quantity of grid electricity used to operate the carbon capture and storage facilities should be tracked.	Related
P8 Generation of Electricity for	The generation of electricity in Alberta is achieved with a mixture of energy sources. Most of the	Related

Use by Carbon Capture and Storage Facilities	electricity generation in Alberta is from coal-fired and natural gas-fired generating stations, with lesser contributions from hydro, wind, biomass and waste heat recovery power generating facilities. The quantity of electricity should be tracked to estimate related greenhouse gas emissions from electricity usage to operate the carbon capture and storage facilities (e.g. electrically-driven compressors would be major electricity users). This electricity can be either sourced from the power pool on the grid or contracted (i.e. under a power purchase agreement). The project proponent will need to delineate all new electric equipment used to capture, transport and inject and store CO ₂ and the source of the electricity (power pool or contracted from a specific source). Excludes co-generation.	
P9 Off-Site Heat and Power Generation	Heat and electricity inputs may be required for CO ₂ capture and processing, compression, dehydration, transport and injection. Heat and electricity may be generated independently or may be generated at third party generation facilities. Important quantities to be tracked are the quantity and type of fossil fuels consumed to generate heat and electrical power and the quantity of electricity consumed.	Related
On-Site Sources and Sinks During Project		
P10 On-Site Heat and Power Generation	Heat and electricity inputs may be required for CO ₂ capture and processing, compression, dehydration, transport and injection. Heat and electricity may be generated independently or may be generated at an on-site generation unit. Important quantities to be tracked are the quantity and type of fossil fuels consumed to generate heat and electrical power and the quantity of electricity consumed.	Controlled
P11 Carbon Capture and Storage Facility Operation	Operation of the injection unit may require the use of pumps and pressure equipment. Mechanical equipment may be required to treat the CO ₂ rich gas stream in order meet the required specifications for injection. This may require several energy inputs such as natural gas, propane and diesel and may arise from stationary sources or mobile sources. Quantities and types for each of the energy inputs would be tracked. The CO ₂ pipeline and injection well will need to be inspected and monitored for leaks on a regular basis. The geological formation must also be monitored and tested regularly for signs of CO ₂ leakage or migration, as per the measurement, monitoring and verification plan submitted with, and accepted in conjunction with, the Carbon Sequestration Lease (see Section 1.2). Greenhouse gas emissions will result from fossil fuels consumed for maintenance activities for leak prevention or repair.	Controlled
P12 Venting of CO ₂ at Capture Site	In the project condition, some CO ₂ may be vented from the hydrogen production units as it will not be possible to achieve 100% capture efficiency. Venting of CO ₂ may also be necessary for equipment maintenance or emergency shutdowns. Instances of venting should be logged and the duration of the venting event and the estimated volume of CO ₂ vented should be recorded.	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. It is expected that the gas will be primarily composed of H ₂ and CO ₂ . Greenhouse gas emissions are attributed the release of CO ₂ to the atmosphere.	Related

P14 Venting of CO ₂ During Compression/Dehydration	Emergency or planned vents of CO ₂ may be necessary for compressor/dehydrator maintenance or emergency shutdowns. Instances of venting should be logged, the duration of the venting event and the volume of CO ₂ vented should be recorded.	Controlled
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. It is expected that the gas will be composed of CO ₂ with trace amounts of other gases.	Related
P16 Venting of CO ₂ During Transportation	Emergency or planned vents of CO ₂ may be necessary for pipeline maintenance or shutdowns. Instances of venting should be logged and the duration of the venting event and the estimated volume of CO ₂ vented should be recorded.	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. It is expected that the gas will be composed of CO ₂ with trace amounts of other gases.	Related
P18 Venting of CO ₂ at Injection Well Sites	Emergency or planned vents of CO ₂ may be necessary for injection well work overs, mechanical integrity checks and maintenance. Instances of venting should be logged and the duration of the venting event and the estimated volume of CO ₂ vented should be recorded.	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. It is expected that the gas will be composed of CO ₂ with trace amounts of other gases.	Related
P20 Emissions from Subsurface to Atmosphere	Accidental emissions may occur by way of gas migration through undetected faults, fractures and/or subsurface equipment (due to compromised casing/cement/wellhead or packer/tubing) to atmosphere.	Related
Downstream Sources and Sinks During Project		
P21 Loss, Disposal, or Recycling of Materials Used in CO ₂ Capture Processes	Material inputs will need to be either disposed or recycled at the end of their useful life. Greenhouse gas emissions are attributed to the transport of materials to industrial landfill or the processes by which the material is recycled (ex. amine recycling or disposal). This source/sink also accounts for greenhouse gas emissions associated to loss of material during project operation.	Related
Downstream Sources and Sinks After Project		
P22 Decommissioning Carbon Capture and Storage of Facilities	Once the carbon capture and storage facilities are no longer operational, the infrastructure may need to be decommissioned. This may involve 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 would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to decommission the facilities.	Related

1 **4.0 Quantification**

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

9
10 Emissions that increase or decrease materially as a result of the project must be included
11 and associated greenhouse gas emissions must be quantified as part of the project
12 condition.

13
14 All sources and sinks identified in Table 3 and Table 5, above, are listed in Table 6
15 below. Each source and sink is listed as include or excluded. Justification for these
16 choices is provided.

1 **Table 6: Comparison of Sources and Sinks**

1. Identified Source/Sink	2. Baseline (C, R, A)**	3. Project (C, R, A)**	4. Include or Exclude from Quantification	5. Justification for Inclusion/Exclusion
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 is likely to have a material impact on projects as there are increased greenhouse gas emissions from upstream chemical production associated with project period chemical usage.
P5 Extraction/Processing and Transportation of Fuels Used On-Site for Heat and Power 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 and Power 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 Grid Electricity	N/A	Related	Exclude	For consistency with other government-approved protocols under the Alberta Offset System, this source/sink has been excluded due to immateriality.
P8 Generation of Electricity for Use by Carbon Capture and Storage Facilities	N/A	Related	Include	This source/sink is likely to have a material impact on projects.
P9 Off-Site Heat and Power Co-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 Industrial process emissions at Hydrogen Production Facility	Controlled	N/A	Include	This source/sink is the data point against which all project emissions are subtracted and establishes the baseline emissions.
P10 On-Site Heat and Power Co-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 amount of vented CO ₂ in the baseline is calculated from the metered amount of CO ₂ captured and injected in the project condition. The protocol requires that this meter to be located downstream of the capture site and transport system,
P13 Fugitive Emissions at Capture Site	N/A	Related	Exclude	

1. Identified Source/Sink	2. Baseline (C, R, A)**	3. Project (C, R, A)**	4. Include or Exclude from Quantification	5. Justification for Inclusion/Exclusion
P14 Venting of CO ₂ During Compression/Dehydration	N/A	Controlled	Exclude	right at the point(s) of injection for accuracy (direct calculation method). In some project cases, all of the CO ₂ from the primary process was vented in the baseline, thus any fugitive emissions that occur upstream of the injection wells in the project condition would be equivalent to emissions that would have occurred in the baseline and can therefore be excluded from the quantification. This protocol does not allow indirect calculation methods due to its decreased accuracy.
P15 Fugitive Emissions During Compression/ Dehydration	N/A	Related	Exclude	
P16 Venting of CO ₂ During Transportation	N/A	Controlled	Exclude	
P17 Fugitive Emissions During Transportation	N/A	Related	Exclude	
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 and the resulting emissions may have material impact on the project.
P19 Fugitive Emissions at Injection Well Sites	N/A	Related	Include	Fugitive emissions accounted under this source/sink are those emitted at the injection site from surface facilities only. Fugitive emissions upstream of metering equipment would be equivalent under the baseline and project condition and therefore may be excluded. Fugitives downstream of the metering equipment and upstream of the subsurface are included. Fugitives down hole are accounted under P20 Emissions from Subsurface to Atmosphere.
P20 Emissions from Subsurface to Atmosphere	N/A	Related	Include	Under normal operation, this source/sink may be neglected, however to account for leakage events, this source/sink is included. A measurement, monitoring and verification plan, as described in Section 5.0 shall be used to identify emissions from the subsurface to the atmosphere.
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 as there are increased greenhouse gas emissions associated with downstream chemical loss, disposal or recycling with project period chemical usage.
Construction/Decommissioning Sources and Sinks				
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 Offset System.

1. Identified Source/Sink	2. Baseline (C, R, A)**	3. Project (C, R, A)**	4. Include or Exclude from Quantification	5. Justification for Inclusion/Exclusion
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.
P3 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 Offset System.
P22 Decommissioning 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 Offset System.

1 **Where C is Controlled, R is Related, and A is Affected.

DRAFT

4.1 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 in Table 7, 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.

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

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{Un-Captured Emissions}}$$

$$\begin{aligned} \text{Emissions}_{\text{Project}} = & \text{Emissions}_{\text{Production and Delivery of Material Inputs}} + \text{Emissions}_{\text{Fuel Extraction and Processing}} \\ & + \text{Emissions}_{\text{Electricity Consumption}} + \text{Emissions}_{\text{Off-Site Heat and Power Co-Generation}} + \\ & \text{Emissions}_{\text{On-Site Heat and Power Co-Generation}} + \text{Emissions}_{\text{Carbon Capture and Storage Facility Operation}} \\ & + \text{Emissions}_{\text{Venting of CO}_2 \text{ at Injection Well Sites}} + \text{Emissions}_{\text{Fugitives from Injection Well Sites}} + \\ & \text{Emissions}_{\text{Subsurface to Atmosphere}} + \text{Emissions}_{\text{Loss, Disposal or Recycling of Material Inputs}} \end{aligned}$$

$$\text{Total CO}_2 \text{ Equivalent Emissions} = \sum (\text{CO}_2 \text{ emissions}) + \sum (\text{CH}_4 \text{ emissions}) * \text{GWP}_{\text{CH}_4} + \sum (\text{N}_2\text{O emissions}) * \text{GWP}_{\text{N}_2\text{O}}$$

Where:

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

- $\text{Emissions}_{\text{Un-Captured Emissions}}$ = emissions under B1 Un-Captured Emissions

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

- $\text{Emissions}_{\text{Production and Delivery of Material Inputs}}$ = emissions under P4 Production and Delivery of Material Inputs for Use by Carbon Capture and Storage Facility
- $\text{Emissions}_{\text{Fuel Extraction and Processing}}$ = emissions under P5 and P6 Extraction/ Processing and Transportation of Fuels Used On/ Off-Site for Heat and Power Generation
- $\text{Emissions}_{\text{Electricity Consumption}}$ = emissions under P8 Generation of Electricity for Use by Carbon Capture and Storage Facility
- $\text{Emissions}_{\text{Off-Site Heat and Power Generation}}$ = emissions under P9 Off-Site Heat and Power Generation
- $\text{Emissions}_{\text{On-Site Heat and Power Generation}}$ = emissions under P10 On-Site Heat and Power Generation
- $\text{Emissions}_{\text{Carbon Capture and Storage Facility Operation}}$ = emissions under P11 Carbon Capture and Storage Facility Operation
- $\text{Emissions}_{\text{Venting CO}_2 \text{ at Injection Well Sites}}$ = emissions under P18 Venting CO₂ at Injection Well Sites

- 1 • Emissions_{Fugitives from Injection Well Sites} = emissions under P19 Emissions from Fugitives
2 at Injection Well Sites
- 3 • Emissions_{Subsurface to Atmosphere} = emissions under P20 Emissions from Subsurface to
4 Atmosphere
- 5 • Emissions_{Loss, Disposal or Recycling of Material Inputs} = emissions under P21 Emissions from
6 Loss, Disposal or Recycling of Material Inputs
- 7 CO₂ Equivalent Emissions = sum of all greenhouse gas emissions converted to CO₂ equivalent
8 terms
- 9 • GWP_{CH₄} = The Global Warming Potential of Methane is 21
- 10 • GWP_{N₂O} = The Global Warming Potential of Nitrous Oxide is 310

1 **Table 7: Quantification Methodology**

1. Project/ Baseline Sources/Sinks	2. Parameter / Variable	3. Units	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
Baseline Sources and Sinks						
B1 Un-Captured Emissions	Emissions_{Un-Captured Emissions} = Emissions_{Storage in Deep Saline Aquifers} Where, Emissions_{Storage in Deep Saline Aquifers} = $\sum (\text{Vol. Gas Injected} * \%_{\text{CO}_2} * \rho_{\text{CO}_2})$; $\sum (\text{Vol. Gas Injected} * \%_{\text{CH}_4} * \rho_{\text{CH}_4})$; $\sum (\text{Vol. Gas Injected} * \%_{\text{N}_2\text{O}} * \rho_{\text{N}_2\text{O}})$					
	Emissions _{Un-Captured Emissions}	kg of CO ₂	N/A	The calculation of baseline emissions at the industrial facility relies on data collected during the project condition and does not consider those emission sources that are not impacted by the implementation of the CO ₂ capture equipment (e.g. those emissions that are functionally equivalent). The only quantified emission source in the baseline is related to the quantity of CO ₂ that is being captured and injected in the project condition.	N/A	Quantity being calculated. Note that this value refers to the baseline quantity of CO ₂ that would have been emitted to the atmosphere in the absence of the carbon capture and storage project.
	Emissions _{Storage in Deep Saline Aquifers}	kg of CO ₂ e	N/A	This value refers to the metered quantity of CO ₂ sequestered (removed from the atmosphere) in deep saline aquifer in the project condition.	N/A	Direct metering is standard practice. Frequency of metering is highest level possible.
	Volume of Gas Injected into Geological Formation / Vol. Gas Injected	m ³	Measured	Direct metering of volume of gas injected into the saline geological formation in the project condition, measured directly at each injection well.	Continuous metering	Direct metering is standard practice. Frequency of metering is highest level possible.
CO ₂ Concentration in Injected Gas / % CO ₂	% Volume	Measured	Direct measurement of the composition prior to input into the pipeline and prior to injection at the well head.	Daily	Composition should be consistent at the point of input into the pipeline as prior gas processing steps would be closely	

						controlled. Any changes in composition would be detected at upstream processes.
	Density of CO ₂ / ρ _{CO2}	kg/m ³	Estimated	Constant value for conditions at which volumetric meter reports volume (1.87 kg/m ³ at 15°C and 1 atmosphere, the reference conditions commonly used by the oil and gas industry in North America)	N/A	Reference value. If the flow meters used in the project condition measure the volume of gas at other temperatures and pressures then these conditions should be corrected to a single set of reference conditions.
	CH ₄ Concentration in Injected Gas / % CH ₄	% Volume	Measured	Direct measurement of the composition prior to input into the pipeline and prior to injection at the well head.	Daily	Composition should be consistent at the point of injection as prior gas processing steps would be closely controlled. Any changes in composition would be detected at upstream processes.
	Density of CH ₄ / ρ _{CH4}	kg/m ³	Estimated	Constant value for conditions at which volumetric meter reports volume (0.677kg/m ³ at 15°C and 1 atmosphere, the reference conditions commonly used by the oil and gas industry in North America)	N/A	Reference value. If the flow meters used in the project condition measure the volume of gas at other temperatures and pressures then these conditions should be corrected to a single set of reference conditions.
	N ₂ O Concentration in Injected Gas / % N ₂ O	% Volume	Measured	Direct measurement of the composition prior to input into the pipeline and prior to injection at the well head.	Daily	Composition should be consistent at the point of injection as prior gas processing steps would be closely controlled. Any changes in

						composition would be detected at upstream processes.
	Density of N ₂ O / ρ _{N2O}	kg/m ³	Estimated	Constant value for conditions at which volumetric meter reports volume (1.84kg/m ³ at 15°C and 1 atmosphere, the reference conditions commonly used by the oil and gas industry in North America)	N/A	Reference value. If the flow meters used in the project condition measure the volume of gas at other temperatures and pressures then these conditions should be corrected to a single set of reference conditions.
Project Sources and Sinks						
P4 Production and Delivery of Material Inputs used in CO ₂ Capture Process	Emissions Production & Delivery of Material Inputs = $\sum (\text{Vol. Input}_i * \text{EF Input}_{i\text{CO}_2})$; $\sum (\text{Vol. Input}_i * \text{EF Input}_{i\text{CH}_4})$; $\sum (\text{Vol. Input}_i * \text{EF Input}_{i\text{N}_2\text{O}})$					
	Emissions Production & Delivery of Material Inputs	kg of CO ₂ ; kg CH ₄ ; kg N ₂ O	N/A	N/A	N/A	Quantity being calculated in aggregate based on quantity of inputs used throughout the carbon capture and storage operations.
	Total Volume of Material Inputs Consumed for Carbon Capture and Storage Facility Operation / Vol. Input _i	L/ m ³ / Other	Estimated	Estimation of the volume of material inputs consumed for the carbon capture and storage project.	Annual	Engineering report will specify the volume of material input required for an appropriately sized Carbon Capture and Storage Facility. Represents most reasonable means of estimation.
	CO ₂ Emissions Factor for Production and Delivery of Each Type of Material Input / EF	kg CO ₂ per L / m ³ / other	Estimated	Project Specific Design	Annual	Production and delivery estimates for the emission factors for the material inputs.

	Input _{iCO2}					
	CH ₄ Emissions Factor for Production and Delivery of Each Type of Material Input / EF Input _{iCH4}	kg CH ₄ per L / m ³ / other	Estimated	Project Specific Design	Annual	Production and delivery estimates for the emission factors for the material inputs.
	N ₂ O Emissions Factor for Production and Delivery of Each Type of Material Input / EF Input _{iN2O}	kg N ₂ O per L / m ³ / other	Estimated	Project Specific Design	Annual	Production and delivery estimates for the emission factors for the material inputs.
P5 & P6 Extraction/ Processing and Transportation of Fuels Used On/Off-Site for Heat and Power Generation	Emissions_{Fuel Extraction and Processing} = $\sum (\text{Vol. Fuel}_i * \text{EF Fuel}_{iCO2})$; $\sum (\text{Vol. Fuel}_i * \text{EF Fuel}_{iCH4})$; $\sum (\text{Vol. Fuel}_i * \text{EF Fuel}_{iN2O})$					
	Emissions _{Fuel Extraction and Processing}	kg of CO ₂ ; kg CH ₄ ; kg N ₂ O	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 Volume of Fossil Fuels Consumed to Operate Carbon Capture and Storage Facilities / Vol. Fuel _i	L/ m ³ / Other	Measured	Direct measurement of the volume 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 at each component of the carbon capture and storage operations.
	CO ₂ Emissions Factor for Extraction and Processing of Each Type of Fuel / EF Fuel _{iCO2}	kg CO ₂ per L / m ³ / other	Estimated	From CAPP reference documents. Refer to Appendix A	Annual	Reference values represent best available emission factors for fuel extraction and processing.
	CH ₄ Emissions Factor for Extraction and Processing of Each Type of Fuel / EF Fuel	kg CH ₄ per L / m ³ / other	Estimated	From CAPP reference documents. Refer to Appendix A	Annual	Reference values represent best available emission factors for fuel extraction and

	i CH ₄					processing.
	N ₂ O Emissions Factor for Extraction and Processing of Each Type of Fuel / EF Fuel	kg N ₂ O per L / m ³ / other	Estimated	From CAPP reference documents. Refer to Appendix A	Annual	Reference values represent best available emission factors for fuel extraction and processing.
	i N ₂ O					
P8 Generation of Electricity for Use by Carbon Capture and Storage Facilities	Emissions Electricity Consumption = $\sum \text{Electricity}_{\text{Grid}} * \text{EF}_{\text{Grid CO}_2\text{e}} + \sum \text{Electricity}_{\text{Ded. Off-Site}} * \text{EF}_{\text{Ded. Off-Site CO}_2\text{e}}$					
	Emissions Electricity Consumption	kg CO _{2e}	N/A	N/A	N/A	Quantity being calculated in aggregate based on quantity of grid electricity used at each component of the carbon capture and storage operations.
	Incremental Grid Electricity Consumption for Carbon Capture and Storage Project / Electricity	kWh	Measured	Direct measurement of grid electricity consumption at each facility involved in the capture, compression, transport, injection, and storage of CO ₂ less the total electricity contracted from specific source facilities. The total electricity consumption should be calculated as the sum of electricity consumption across individual components of the carbon capture and storage project. Where individual metering is not present or disaggregation of carbon capture and storage related electricity consumption is not possible, the maximum rated kW capacity or maximum design loading of the relevant equipment may be used with a conservative estimate of equipment	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.

				operating hours to estimate the electricity consumption. The total electricity contracted from specific source facilities should be calculated as per the guidance below. Excludes co-generation.		
	Grid Emission Intensity Factor for Electricity Generation / EF _{Grid CO_{2e}}	kg CO _{2e} / kWh	Estimated	Obtained from Alberta Environment offset project guidance documents. Refer to Appendix A.	Annual	Reference value adjusted periodically by Alberta Environment.
	Incremental Dedicated Off-Site Electricity Consumption for Carbon Capture and Storage Project / Electricity	kWh	Measured	Direct measurement of dedicated off-site electricity consumption at each facility involved in the capture, compression, transport, injection, and storage of CO ₂ less the total electricity contracted from specific source facilities. The total electricity consumption should be calculated as the sum of electricity consumption across individual components of the carbon capture and storage project. Where individual metering is not present or disaggregation of carbon capture and storage -related electricity consumption is not possible, the maximum rated kW capacity or maximum design loading of the relevant equipment may be used with a conservative estimate of equipment operating hours to estimate the electricity consumption. The total electricity contracted from specific source facilities should be calculated as per the guidance below.	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.

	Dedicated Off-Site Emission Intensity Factor for Electricity Generation / EF _{Ded. Off-Site CO_{2e}}	kg CO _{2e} / kWh	Calculated	Calculated based on emission intensity of the off-site electricity generation facility operation. If the electricity is generated from a renewable source that has already claimed greenhouse gas benefits, the emission intensity factor will be the same as the grid emission intensity factor.	Annual	Annual emission intensity factor adjustment to account for equipment changes. Both the supplier and user cannot claim greenhouse gas benefit for each MWh of renewable energy produced.
P9 Off-Site Heat and Power Generation	<p>Emissions Off-Site Heat and Power Generation = $\sum (\text{Vol. Fuel}_{\text{CCS}} * \text{EF Fuel}_{\text{CO}_2})$; $\sum (\text{Vol. Fuel}_{\text{CCS}} * \text{EF Fuel}_{\text{CH}_4})$; $\sum (\text{Vol. Fuel}_{\text{CCS}} * \text{EF Fuel}_{\text{N}_2\text{O}})$</p> <p>Where,</p> <p>1) $\text{Vol. Fuel}_{\text{CCS}} = \text{Vol. Fuel}_{\text{Heat CCS}} + \text{Vol. Fuel}_{\text{Elec CCS}}$</p> <p>2) $\text{Vol. Fuel}_{\text{Heat CCS}} = (\text{Heat}_{\text{CCS}} / \text{Heat}_{\text{Total}}) * \text{Vol. Fuel}_{\text{Heat Gen}}$</p> <p>3) $\text{Vol. Fuel}_{\text{Elec CCS}} = (\text{Elec}_{\text{CCS}} / \text{Elec}_{\text{Total}}) * \text{Vol. Fuel}_{\text{Elec Gen}}$</p> <p>If direct measurement is not available for 2&3, an optional calculation is provided,</p> <p>4) $\text{Vol. Fuel}_{\text{Heat Gen}} = \text{Total Fuel}_{\text{Heat \& Power}} * (\text{Heat}_{\text{Total}} / e_{\text{Heat}}) / (\text{Heat}_{\text{Total}} / e_{\text{Heat}} + \text{Elec}_{\text{Total}} / e_{\text{Elec}}]$</p> <p>5) $\text{Vol. Fuel}_{\text{Elec Gen}} = \text{Total Fuel}_{\text{Heat \& Power}} - \text{Vol. Fuel}_{\text{Heat Gen}}$</p>					
	Emissions Off-Site Heat and Power Generation	kg of CO ₂ ; kg CH ₄ ; kg N ₂ O	N/A	N/A	N/A	Quantity being calculated based on quantity of heat and power purchased from third party facilities.
	Proportionate Volume of Fossil Fuels Consumed to Generate Heat and Power at Off-Site Facilities for Use by the CCS Project / Vol. 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 generation unit that is supplied to the carbon capture and storage project is appropriate given that multiple energy users may source thermal energy or electricity from a single combined heat and power

						plant. Direct metering of thermal energy and electricity is appropriate.
Volume of Fossil Fuels Consumed to Generate Heat at Off-Site Generation Facilities for Use by the CCS Project / Vol. Fuel _{Heat CCS}	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 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.	
		Calculated	Calculated based on amount of heat used by the carbon capture and storage project as compared to the total heat output from the third party generation unit.	Monthly	Calculated according to best practice guidance from the Climate Registry General Reporting Protocol v1.1 ⁶	
Volume of Fossil Fuels Consumed to Generate Electricity at Off-Site Generation Facilities for Use by the CCS Project / Vol. Fuel _{Elec CCS}	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 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.	
		Calculated	Calculated based on amount of electricity used by the carbon capture and storage project as compared to the total electricity output from the third party generation unit.	Monthly	Calculated according to best practice guidance from the Climate Registry General Reporting Protocol v1.1	
Total Volume of Fossil Fuels Consumed to Generate Heat and Power at Off-Site Generation Facilities / Total Fuel _{Heat & Power}	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.	
Total Quantity of	GJ	Measured	Direct metering of quantity of thermal	Continuous	Direct metering of	

⁶ The Climate Registry General Reporting Protocol Version 1.1. May 2008. Refer to Section 12.3, page 71 for cogeneration emission calculation equations. <http://www.theclimateregistry.org/resources/protocols/general-reporting-protocol/>

	Thermal Energy Supplied to the CCS Project from Off-Site Generation Facilities / Heat _{CCS Project}			energy delivered to 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.	metering	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 Cogeneration Facilities / Elec _{CCS Project}	GJ	Measured	Direct metering of the quantity of electricity delivered to the carbon capture and storage project from third party cogeneration plants or other direct connected power generation facilities. Note that grid electricity usage is accounted for under a separate source and/or sink and should not be included in this calculation.	Continuous Metering	Continuous direct metering represents the industry practice and the highest level of detail.
	Total Quantity of Thermal Energy Generated by Facilities that Provide Heat to the CCS Project / Heat _{Total}	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 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	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

				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.		heat distribution system based on the specific temperatures and pressures of the heat transfer medium is consistent with best practices.
Total Quantity of Electricity Generated by Facilities that Provide Electricity to the CCS Project / Elec _{Total}	GJ	Measured		Direct metering of quantity of electricity delivered to all direct connected facilities from the generation plant (including the carbon capture and storage facilities) and metering of the total electricity distributed to the regional electricity grid.	Continuous Metering	Continuous direct metering represents the industry practice and the highest level of detail.
Total Volume of Fossil Fuels Consumed to Generate Heat at Off-Site Cogeneration Facilities / Vol. Fuel _{Heat Gen}	L/ m ³ / Other	Calculated		Calculated based on heat generation efficiency of generation unit.	Monthly	Calculated according to best practice guidance from the Climate Registry General Reporting Protocol v1.1
Total Volume of Fossil Fuels Consumed to Generate Electricity at Off-Site Generation Facilities / Vol. Fuel _{Elec Gen}	L/ m ³ / Other	Calculated		Calculated based on heat generation efficiency of generation unit.	Monthly	Calculated according to best practice guidance from the Climate Registry General Reporting Protocol v1.1
Efficiency of Heat Generation at Third Party Generation Unit / e _{Heat}	-	Estimated		Estimated based on total quantity of thermal energy output from cogeneration unit and input energy content of fuels combusted by the cogeneration unit. If a heat generation efficiency is unavailable, use a default efficiency of 80%. ⁷	Annual	Estimation is reasonable given consistency of generation unit operations.

⁷ 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 guidance under the Specified Gas Emitters Regulation (http://environment.alberta.ca/documents/Compliance_Guidance_v4.0.pdf).

	Efficiency of Electricity Generation at Third Party Generation Unit / e_{Elec}	-	Estimated	Estimated based on total quantity of electricity output from cogeneration unit and input energy content of fuels combusted by the cogeneration unit. If an electric efficiency is unavailable use a default efficiency of 35%. ⁸	Annual	Estimation is reasonable given consistency of generation unit operations.
	CO ₂ Emissions Factor for Each Type of Fossil Fuel / $EF_{Fuel_{iCO_2}}$	kg CO ₂ per L, m ³ or other	Estimated	From Environment Canada reference documents. Refer to Appendix A.	Annual	Reference values adjusted annually as part of Environment Canada's National Inventory Report.
	CH ₄ Emissions Factor for Each Type of Fossil Fuel / $EF_{Fuel_{iCH_4}}$	kg CH ₄ per L, m ³ or other	Estimated	From Environment Canada reference documents. Refer to Appendix A.	Annual	Reference values adjusted annually as part of Environment Canada's National Inventory Report.
	N ₂ O Emissions Factor for Each Type of Fossil Fuel / $EF_{Fuel_{iN_2O}}$	kg N ₂ O per L, m ³ or other	Estimated	From Environment Canada reference documents. Refer to Appendix A.	Annual	Reference values adjusted annually as part of Environment Canada's National Inventory Report.
P10 On-Site Heat and Power Generation	Emissions_{On-Site Heat and Power Generation} = $\sum (\text{Vol. Fuel}_{CCS} * EF_{Fuel_{CO_2}})$; $\sum (\text{Vol. Fuel}_{CCS} * EF_{Fuel_{CH_4}})$; $\sum (\text{Vol. Fuel}_{CCS} * EF_{Fuel_{N_2O}})$ Where, 1) $\text{Vol. Fuel}_{CCS} = \text{Vol. Fuel}_{Heat_{CCS}} + \text{Vol. Fuel}_{Elec_{CCS}}$ 2) $\text{Vol. Fuel}_{Heat_{CCS}} = (\text{Heat}_{CCS} / \text{Heat}_{Total}) * \text{Vol. Fuel}_{Heat_{Gen}}$ 3) $\text{Vol. Fuel}_{Elec_{CCS}} = (\text{Elec}_{CCS} / \text{Elec}_{Total}) * \text{Vol. Fuel}_{Elec_{Gen}}$ If direct measurement for 2&3 is not available, an optional calculation is provided, 4) $\text{Vol. Fuel}_{Heat_{Gen}} = \text{Total Fuel}_{Heat \& Power} * (\text{Heat}_{Total} / e_{Heat}) / (\text{Heat}_{Total} / e_{Heat} + \text{Elec}_{Total} / e_{Elec})$ 5) $\text{Vol. Fuel}_{Elec_{Gen}} = \text{Total Fuel}_{Heat \& Power} - \text{Vol. Fuel}_{Heat_{Gen}}$					
	Emissions _{On-Site Heat and Power Generation}	kg of CO ₂ ; kg CH ₄ ; kg N ₂ O	N/A	N/A	N/A	Quantity being calculated based on quantity of heat and power sourced from

⁸ 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.

						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 / Vol. 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 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 / Vol. Fuel _{Heat CCS}	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.
			Calculated	Calculated based on amount of heat used by the carbon capture and storage project as compared to the total heat output from the on-site generation unit.	Monthly	Calculated according to best practice guidance from the Climate Registry General Reporting Protocol v1.1 ⁹
	Volume of Fossil Fuels Consumed to Generate Electricity at On-Site Generation Facilities for Use by the CCS	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	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.

⁹ The Climate Registry General Reporting Protocol Version 1.1. May 2008. Refer to Section 12.3, page 71 for cogeneration emission calculation equations. <http://www.theclimateregistry.org/resources/protocols/general-reporting-protocol/>

	Project / Vol. Fuel _{Elec} CCS			and storage project.		
			Calculated	Calculated based on amount of electricity used by the carbon capture and storage project as compared to the total electricity output from the on-site generation unit.	Monthly	Calculated according to best practice guidance from the Climate Registry General Reporting Protocol v1.1
	Total Volume of Fossil Fuels Consumed to Generate Heat and Power at the Combined Heat and Power Generation Facilities / Total Fuel _{Heat & Power}	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.
Total Quantity of Thermal Energy Supplied to the CCS Project from Generation Facilities / Heat _{CCS Project}	GJ	Measured	Direct metering of quantity of thermal energy delivered to 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 Project}	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.
	Total Quantity of Thermal Energy Supplied to End Users by the Generation Facility in the Project Condition / Heat _{Gen}	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 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.	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 End Users by the Generation Facility in the Project Condition / Elec _{Gen}	GJ	Measured	Direct metering of quantity of electricity delivered to all direct connected facilities from the generation plant (including the carbon capture and storage facilities) and metering of the total electricity distributed to the regional electricity grid.	Continuous Metering	Continuous direct metering represents the industry practice and the highest level of detail.
	Total Volume of Fossil Fuels Consumed to Generate Heat at On-	L/ m ³ / Other	Calculated	Calculated based on heat generation efficiency of generation unit.	Monthly	Calculated according to best practice guidance from the Climate

	Site Generation Facilities / Vol. Fuel _{Heat} Gen					Registry General Reporting Protocol v1.1
	Total Volume of Fossil Fuels Consumed to Generate Electricity at On-Site Cogeneration Facilities / Vol. Fuel _{Elec} Gen	L/ m ³ / Other	Calculated	Calculated based on heat generation efficiency of generation unit.	Monthly	Calculated according to best practice guidance from the Climate Registry General Reporting Protocol v1.1
	Efficiency of Heat Generation at On-Site Generation Unit / e _{Heat}	-	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%. ¹⁰	Annual	Estimation is reasonable given consistency of generation unit operations.
	Efficiency of Electricity Generation at On-site Generation Unit / e _{Elec}	-	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%. ¹¹	Annual	Estimation is reasonable given consistency of generation unit operations.
	CO ₂ Emissions Factor for Each Type of Fossil Fuel / EF Fuel _{iCO2}	kg CO ₂ per L, m ³ or other	Estimated	From Environment Canada reference documents. Refer to Appendix A.	Annual	Reference values adjusted annually as part of Environment Canada's National Inventory Report.
	CH ₄ Emissions Factor for Each Type of Fossil	kg CH ₄ per L, m ³	Estimated	From Environment Canada reference documents. Refer to Appendix A.	Annual	Reference values adjusted annually as part

¹⁰ 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 guidance under the Specified Gas Emitters Regulation (http://environment.alberta.ca/documents/Compliance_Guidance_v4.0.pdf).

¹¹ 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.

	Fuel / EF Fuel _{iCH4}	or other				of Environment Canada's National Inventory Report.
	N ₂ O Emissions Factor for Each Type of Fossil Fuel / EF Fuel _{iN2O}	kg N ₂ O per L, m ³ or other	Estimated	From Environment Canada reference documents. Refer to Appendix A.	Annual	Reference values adjusted annually as part of Environment Canada's National Inventory Report.
P11 Carbon Capture and Storage Facility Operation	$\text{Emissions}_{\text{Carbon Capture and Storage Facility Operation}} = \sum (\text{Vol. Fuel}_{\text{Facility Operation}} * \text{EF Fuel}_{i\text{CO}_2}); \sum (\text{Vol. Fuel}_{\text{Facility Operation}} * \text{EF Fuel}_{i\text{CH}_4}); \sum (\text{Vol. Fuel}_{\text{Facility Operation}} * \text{EF Fuel}_{i\text{N}_2\text{O}});$					
	Emissions _{Carbon Capture and Storage Facility Operation}	kg CO ₂ ; kg CH ₄ ; kg N ₂ O;	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/ Vol. 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.
	CO ₂ Emissions Factor for Each Type of Fuel / EF Fuel _{iCO2}	kg CO ₂ per L / m ³ / other	Estimated	From Environment Canada reference documents. Refer to Appendix A.	Annual	Reference values adjusted annually as part of Environment Canada's National Inventory Report.
	CH ₄ Emissions Factor for Each Type of Fuel / EF Fuel _{iCH4}	kg CH ₄ per L / m ³ / other	Estimated	From Environment Canada reference documents. Refer to Appendix A.	Annual	Reference values adjusted annually as part of Environment Canada's National Inventory Report.
	N ₂ O Emissions Factor for Each Type of Fuel / EF Fuel _{iN2O}	kg N ₂ O per L / m ³ / other	Estimated	From Environment Canada reference documents. Refer to Appendix A.	Annual	Reference values adjusted annually as part of Environment Canada's

						National Inventory Report.
P18 Venting of CO ₂ at Injection Well Sites	Emissions_{Venting at Injection Well Sites} = $\sum (\text{Vol. Gas Vented} * \% \text{ CO}_2 * \rho_{\text{CO}_2})$					
	Emissions _{Venting at Injection Well Sites}	Kg of CO ₂	N/A	N/A	N/A	Quantity being calculated
	Volume of Gas Vented / Vol. Gas Vented	M ³	Measured	Direction metering of volume of gas being vented, converted to STP conditions.	Continuous metering	Direct metering is standard practice. Frequency of metering is highest level possible.
	CO ₂ Composition in Vent Gas Stream (Volumetric Basis) / % CO ₂	%	Measured	Direct measurement.	Daily sampling averaged monthly on volumetric basis	Composition may vary throughout the injection of gas stream. Quarterly gas composition measurement is reasonable for operation of an injection facility.
	Density of CO ₂ / ρ_{CO_2}	Kg/m ³	Estimated	Constant value of 1.98 kg/m ³ at STP	N/A	Accepted Value.
P19 Fugitives at Injection Well Sites	Emissions_{Fugitives at Injection Well Sites} = $\sum (\text{Fitting}_i * \text{ER}_{\text{Fitting } i})$					
	Emissions _{Fugitives at Injection Well Sites}	Kg of CO ₂ ; CH ₄	N/A	N/A	N/A	Quantity being calculated
	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}	kg CO ₂	Estimated	Engineering Estimate	Annual	Engineering report will estimate the emission rate for each candidate fitting. Represents most reasonable means of estimation.
P20 Emissions from	Emissions_{Subsurface to Atmosphere} = Mass CO₂ leaked					

Subsurface to Atmosphere						
	Mass of CO ₂ leaked from the Subsurface to Atmosphere/ Mass CO ₂ leaked	kg	Estimated	If a leakage event occurs, the mass of CO ₂ leaked from the subsurface to the atmosphere shall be estimated with a maximum overall uncertainty over the reporting period of ±7.5%. In case overall uncertainty of the applied quantification approach exceeds ±7.5%, an adjustment shall be applied. Refer to Appendix D for further guidance.	N/A	Estimation would be required for reporting to the regulatory authority. Direct measurement is likely not possible, but the use of engineering estimates and uncertainty would be a reasonable approach in the event leakage occurs.
P21 Loss, Disposal or Recycling of Material Used	Emissions Loss, Disposal or Recycling of Material Used = $\sum (\text{Vol. Used}_i * \text{EF Used}_{i\text{CO}_2})$; $\sum (\text{Vol. Used}_i * \text{EF Used}_{i\text{CH}_4})$; $\sum (\text{Vol. Used}_i * \text{EF Used}_{i\text{N}_2\text{O}})$					
	Emissions Loss, Disposal or Recycling of Material Used	kg of CO ₂ ;kg CH ₄ ; kg N ₂ O	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.
	CO ₂ Emissions Factor for Production and Delivery of Each Type of Material Used / EF Used _{iCO2}	kg CO ₂ per L / m ³ / other	Estimated	Project Specific Design	Annual	Loss, disposal or recycling estimates for the emission factors for the materials used.
	CH ₄ Emissions Factor	kg CH ₄	Estimated	Project Specific Design	Annual	Loss, disposal or

	for Production and Delivery of Each Type of Material Used / EF Used _{iCH4}	per L / m ³ / other				recycling estimates for the emission factors for the materials used..
	N ₂₀ Emissions Factor for Production and Delivery of Each Type of Material Used / EF Used _{iN20}	kg N ₂ O per L / m ³ / other	Estimated	Project Specific Design	Annual	Loss, disposal or recycling estimates for the emission factors for the materials used.

DRAFT

1
2
3
4
5
6
7
8
9

5.0 Data Management

Data quality management must be of sufficient quality to fulfill the quantification requirements and be substantiated by actual records for the purpose of verification.

The project developer shall establish and apply quality management procedures to manage data and information. Written procedures will be established for each measurement task outlining responsibility, timing and record location requirements.

5.1 Monitoring

Monitoring in this methodology is discussed as two categories. The first type of monitoring is referred to as ‘Project Monitoring’ and the second type is referred to as ‘Monitoring, Measurement and Verification’ of containment. These monitoring requirements include quantification or measurement activities required to quantify the net greenhouse gas reductions from the carbon capture and storage project and monitoring activities required to ensure that the injected CO₂ is contained within the storage complex permanently.

The monitoring requirements for geological sequestration facilities that inject CO₂ specifically for the purpose of long-term containment in subsurface geologic formations described in this methodology comply with the Alberta-specific requirements for monitoring, measurement, and verification plans as well as other regulatory requirements. As described in Section 1.2, for each specific project, the applicant 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 Alberta¹². As per the regulation, a Carbon Sequestration Lease must include a Measurement, Monitoring and Verification Plan.

5.1.1 Project Monitoring Requirements

The project monitoring plan for the carbon capture and storage project should be designed according to the ISO 14064-2 principles of transparency and accuracy such that the data capture is sufficient to ensure that the quantification and documentation of greenhouse gas reductions is verifiable and replicable. The approach described below is based on a material balance around the captured quantity of CO₂ to ensure accurate monitoring of the parameters required to determine the net mass of CO₂ stored in the relevant formation. Additionally, the monitoring requirements include measurement of relevant parameters to account for all supplemental energy inputs (e.g. fossil fuels and electricity) required for the operation of the carbon capture and storage project.

The project monitoring techniques will 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 such that the quantification of emission

¹² Carbon Sequestration Tenure Regulation, Alberta Regulation 68/2011, Mines and Minerals Act, http://www.gp.alberta.ca/documents/orders/orders_in_council/2011/411/2011_179.html

1 reductions may be easily performed with the need for minimal assumptions and use of
2 contingency procedures. Meters must also be maintained to operate within their designed range
3 of operating conditions and must be calibrated on a regular basis. To ensure a high level of data
4 quality this section provides further guidance on how to implement a monitoring plan that takes
5 into account the location, type of equipment and frequency by which each variable must be
6 measured.

8 **Project Monitoring Plan**

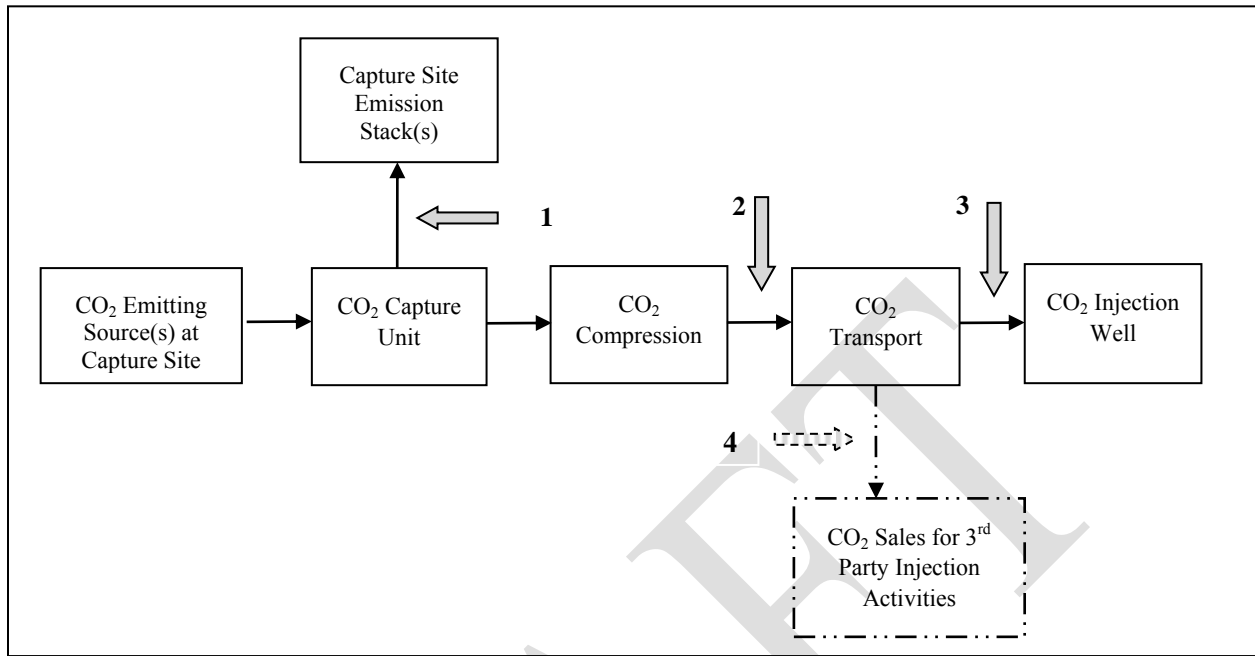
9
10 In order to apply this methodology, the proponent must establish a comprehensive monitoring
11 plan that includes, at minimum, methods to measure and quantify the following data:

- 13 • Incremental energy inputs required to capture, transport, inject and store CO₂
 - 14 ○ Direct fuel inputs
 - 15 ○ Indirect energy inputs or other parasitic loads (e.g. electricity consumption)
- 16 • Quantity of CO₂ emitted from the capture site (un-captured CO₂)
- 17 • Quantity of CO₂ input into the CO₂ transport pipeline
- 18 • Quantity of CO₂ sold to third parties (e.g. for EOR)
- 19 • Quantity of CO₂ injected into each well in the deep saline aquifer (metered at the
20 wellhead)

21
22 This section describes the minimum monitoring requirements to apply this quantification
23 methodology. Measurements must be taken at each of the four locations labelled in Figure 5 in
24 order to track the fate of the CO₂ across the carbon capture and storage chain as it is transferred
25 from the capture site to the deep saline aquifer. Additional measurements may be made to
26 support verification purposes. At each of the measurement points, the mass of CO₂ will need to
27 be determined based on the volumetric or mass flow and composition of the gas stream. Note
28 that Figure 5 does not include measurements as part of the measurement, monitoring and
29 verification plan nor does it illustrate measurement points related to energy inputs for the carbon
30 capture and storage project.

31

1 **Figure 5: Generalized Monitoring Locations for CO₂ Mass Balance Calculations**
 2



3
 4
 5 The measurement and monitoring locations required to complete a material balance around the
 6 captured and injected CO₂ according to Figure 5 are as follows:

- 7 1. At the point where the non-captured CO₂ is emitted from the capture site;
- 8 2. At the point where the CO₂ stream is transferred from the capture site into the gas
 9 transport facilities, measured at the discharge from the compression equipment into the
 10 pipeline;
- 11 3. Immediately upstream of each injection well; and
- 12 4. At each point of custody transfer where CO₂ is sold to third parties (e.g. for EOR), should
 13 CO₂ sales be applicable.

14
 15 The following table (Table 8) provides guidance on the minimum monitoring requirements for
 16 each of the locations specified in Figure 5, above.

17

1 **Table 8: Measurement and Monitoring Guidance for Completing a CO₂ Balance**

1. Variable	2. Locations of Measurement	3. Measurement Frequency	4. Additional Guidance
Flow rate of gas stream (containing primarily CO ₂)	Locations 1- 4	Continuous measurement of the gas flow rate, where continuous measurement is defined as one measurement every 15 minutes.	<p>Flow meters at location 2 must 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. At location 3 the flow meters should be as close as possible to the injection wellheads to ensure accurate measurement of the injected volumes.</p> <p>The flow meter readings must be temperature and pressure compensated and density estimates used according to this protocol should be adjusted to correspond to corrected standardized temperatures and pressures.</p> <p>Flow meters shall be placed based on manufacturer recommendations and shall operate within manufacturers specified operating conditions at all times.</p> <p>Flow meters must be calibrated according to manufacturer specifications and shall be checked/calibrated on regular intervals according to these specifications.</p> <p>Clear transfer of ownership shall be made for CO₂ supplied at Location 4 (3rd party injection activity)</p>
Concentration of CO ₂ in gas stream	Locations 1-4 Locations for 3rd Party Sales	Continuous measurement of the gas composition, where continuous measurement is defined as one measurement every 15 minutes	The gas composition shall be metered downstream of the capture and processing equipment at the point where CO ₂ is input into the pipeline.

2
3 In addition to taking volume and composition measurements to monitor the amount of CO₂ that
4 is injected into the formation, it is also necessary to monitor the incremental energy inputs (fossil
5 fuels and electricity) required to operate the carbon capture and storage project. The general
6 monitoring requirements for fossil fuel and electricity inputs are listed in Table 9, below.
7

1 **Table 9: Measurement and Monitoring Guidance for Energy Inputs to the Carbon Capture and**
 2 **Storage Project**

Variable	Units of Measurement	Measurement Frequency	Additional Guidance
Volume of fossil fuels combusted (gaseous)	ft ³ or m ³	Continuous measurement of the gas flow rate, where continuous measurement is defined as one measurement every 15 minutes.	<p>The flow meter readings must be temperature and pressure compensated and density estimates used according to this protocol should be adjusted to correspond to corrected standardized temperatures and pressures.</p> <p>Flow meters shall be placed based on manufacturer recommendations and shall operate within manufacturers specified operating conditions at all times.</p> <p>Flow meters must be calibrated according to manufacturer specifications and shall be checked/calibrated on regular intervals according to these specifications.</p>
Volume of fossil fuels combusted (liquid or solid)	Liters, kg or metric tonnes	Reconciliation of purchasing records on a quarterly basis and inventory adjustments as needed	Volume or mass measurements would normally be made upon purchase or delivery of the fuel. Reconciliation of purchase receipts or weigh scale tickets would be an acceptable means to determine the volumes of fossil fuels consumed to operate the carbon capture and storage project.
Electricity Consumption	kWh	Continuous measurement of electricity consumption or reconciliation of maximum kW rating for each type of equipment and operating hours	<p>Electricity consumption should be metered continuously wherever possible for the carbon capture and storage project; however, in certain cases other loads may be tied into the same electricity meter and estimates may be required. In these cases the maximum kW rating of each piece of equipment should be used in conjunction with a conservative estimate of operating hours (e.g. 8760 hours per year) to estimate the electricity consumption.</p> <p>Electricity meters must be calibrated by an accredited third party in accordance with manufacturer specifications.</p>

3

4

5.1.2 Measurement, Monitoring and Verification of Containment

5 The second component of the monitoring plan is to ensure that the injected CO₂ is stored
 6 permanently. Each carbon capture and storage project would undertake various monitoring
 7 activities to ensure the safe and permanent storage of CO₂ in accordance with its operating
 8 license requirements based on the characteristics of the deep saline aquifer. In Alberta a number
 9 of regulations are relevant to measurement, monitoring and verification plan and are briefly
 10 discussed below. It is the responsibility of the project proponent to stay up to date with these
 11 evolving regulatory requirements.

12

1 The measurement, monitoring and verification plan is to be submitted as part of the tenure
2 application under the Mines and Minerals Act, as amended by the *Carbon Capture and Storage*
3 *Statutes Amendment Act 2010*. The following directives are particularly relevant for
4 measurement, monitoring and verification as they specify requirements for measurements and
5 monitoring.

- 6 1. **Directives 007 & 017:** Specify requirements for measuring and reporting the amounts
7 of acid gas injected.
- 8 2. **Directive 020:** Specifies minimum requirements for well abandonment, testing to
9 detect leakage and mitigation measures in the event of detecting leakage.
- 10 3. **Directive 051:** Classifies disposal wells according to the injected or disposed fluid
11 and specifies design, operating, and monitoring requirements for each class of wells.
- 12 4. **Directive 065:** Addresses enhanced hydrocarbon recovery, natural gas storage and
13 acid gas disposal. CO₂ is, by definition, an acid gas, and Directive 065 applies to CCS
14 storage schemes. For acid gas disposal projects, this directive specifies requirements
15 to ensure confinement of the disposed fluid and its isolation. This directive also
16 requires the applicant to prove that disposal will not affect hydrocarbon recovery. As
17 per Section 1.2, Directive 065 approval is a prerequisite for use of this protocol.

18
19
20 The preparation and maintenance of a measurement, monitoring and verification plan is integral
21 to the demonstration of permanent storage of CO₂. The measurement, monitoring and
22 verification plan will be specific to the storage complex that CO₂ is being injected into. With
23 respect to the Protocol, the key overall purpose of measurement, monitoring and verification is to
24 ensure containment of CO₂ and that there is no emissions from the subsurface to the atmosphere.
25 The proponent must demonstrate that a measurement, monitoring and verification plan has been
26 prepared and approved in accordance with Alberta regulatory requirements. The proponent must
27 also confirm that the project continues to operate in accordance with the conditions outlined in
28 the operating license. As the carbon capture and storage regulatory processes continue to evolve
29 in Alberta, the proponent must also demonstrate that the measurement, monitoring and
30 verification plan has been updated to comply with any regulatory changes that have been instated
31 since project commissioning.

32
33 Measurement, monitoring and verification activities will be required to meet varying
34 requirements during four distinct phases over the lifecycle of the carbon capture and storage
35 project:

- 36 1. **Pre-Injection Phase:** Monitoring tasks are identified, monitoring solutions evaluated and
37 selected, risks are characterized, and baseline monitoring data are acquired.
- 38 2. **Injection Phase:** Monitoring activities are undertaken to manage containment risk and storage
39 performance, and are adapted through time to ensure their continuing effectiveness.
- 40 3. **Closure Phase:** Some monitoring activities continue to manage containment risk and to
41 demonstrate storage performance is consistent with expectations for permanent storage.
- 42 4. **Post-Closure Phase:** Transfer to the Government of Alberta to continue to validate that the
43 storage complex is stable and that the containment risk has diminished to a level where no further
44 monitoring is required.

1 In summary, the measurement, monitoring and verification program will include both baseline
2 monitoring tasks that are to be conducted during the pre-injection phase of the project and
3 complementary operational monitoring tasks to be conducted periodically during the injection
4 phase. Monitoring will be maintained during the closure phase after injection has ceased. The
5 specific monitoring technologies and activities will be determined and continuously updated and
6 refined based on the site-specific experience gained during the baseline and operational phases of
7 the project. With respect to the Protocol, the overall goal of the measurement, monitoring and
8 verification program is to demonstrate permanent containment of the CO₂ in the subsurface, and
9 that there is no release of CO₂ to the atmosphere.

10 **5.2 Project Documentation**

11 Pertinent documentation must be compiled for verification.

12 **5.2.1 Project Eligibility**

13 Minimum documentation required to prove project eligibility:

- 14 • The name, contact information, and statement of qualification of the Project
15 Developer(s);
 - 16 • Evidence of the project start date;
 - 17 • Evidence of ownership to credits generated;
 - 18 • All applicable permits for project condition;
 - 19 • Evidence that the project results in real emission reductions located in Alberta including
20 legal land location or GPS coordinates of the capture facility and injection wells;
 - 21 • A suitable measurement, monitoring and verification plan; and
 - 22 • Suitable Project Quantification Documentation (see requirements below).
- 23

24 **5.2.2 Baseline Condition Documentation**

25 The documentation of the baseline condition will include:

- 26 • Justification for deviations of the inclusion or exclusion of all baseline sources and sinks
27 from those listed in Table 6;
- 28 • For each project year, the total emissions accounted under each included baseline sources
29 and sinks as listed in Table 6 and included in the baseline by the project proponent;
- 30 • For each project year, calculations applied to measured baseline data and justifications
31 for any deviations from those calculations described in Table 7; and
- 32 • For each project year, the measured baseline data as recorded from the measurement
33 device, before calculations are applied.

34 **5.2.3 Project Quantification Documentation**

35 The documentation of the project condition will include:

- 36 • Justification for deviations of the inclusion or exclusion of all project sources and sinks
37 from those listed in Table 6;
- 38 • For each project year, the total emissions accounted under each included project sources
39 and sinks as listed in Table 6 and included in the project by the project proponent;
- 40 • For each project year, calculations applied to measured project data and justifications for
41 any deviations from those calculations described in 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 requires that Project Developers maintain appropriate supporting information for the project, including all raw data for the project for a period of 7 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 Project Developer must keep the information listed below (in addition to others that will support the project) and disclose all information to the verifier and/or government auditor upon request.

Record Keeping Requirements:

- Raw baseline period data, historic records of emitted CO₂ etc. and other factors within the measurement boundary;
- A record of all adjustments made to raw baseline data with justifications;
- All data and analysis used to support estimates and factors used for quantification;
- Expected end of life date of equipment removed or retrofitted under the project;
- 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 7 years after the project crediting period;
- Project developers must maintain electronic records; while facility operators must maintain original records, which may include hardcopy records; and
- Copies of records should be stored in two locations to prevent loss of data.

5.4 Quality Assurance/Quality Control Considerations

Quality Assurance/Quality Control can also be 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);

- 1 • Checking data integrity on a regular and periodic basis (manual assessment, comparing
2 redundant metered data, and detection of outstanding data/records);
- 3 • Comparing current estimates with previous estimates as a ‘reality check’;
- 4 • Provide sufficient training to operators to perform maintenance and calibration of
5 monitoring devices or contract with qualified third parties;
- 6 • Establish minimum experience and requirements for operators in charge of project and
7 monitoring;
- 8 • Ensuring that the changes to operational procedures continue to function as planned and
9 achieve greenhouse gas reductions;
- 10 • Ensuring that the measurement and calculation system and greenhouse gas reduction
11 reporting remains in place and accurate;
- 12 • Checking the validity of all data before it is processed, including emission factors, static
13 factors, and acquired data;
- 14 • Performing recalculations of quantification procedures to reduce the possibility of
15 mathematical errors;
- 16 • Storing the data in its raw form so it can be retrieved for verification;
- 17 • Protecting records of data and documentation by keeping both a hard and soft copy of all
18 documents;
- 19 • Recording and explaining any adjustment made to raw data in the associated report and
20 files; and
- 21 • A contingency plan for potential data loss.
22

23 **5.5 Liability**

24 Offset projects must be implemented according to the approved protocol and in accordance with
25 government regulations. Alberta Environment reserves the right to audit Offset Credits and
26 associated projects submitted to Alberta Environment for compliance under the *Specified Gas*
27 *Emitters Regulation* and may request corrections based on audit findings.
28

29 Upon obtaining a closure certificate after completion of injection activities, liability for events
30 resulting from these activities is transferred from the project proponent to the Government of
31 Alberta. The project proponent retains liability for all climate obligations resulting from
32 activities and events occurring during project execution and after closure. The Government of
33 Alberta is developing policy guidelines on climate CO₂ liability for the post closure period and
34 will update the regulation or protocol, as required.

35 **5.5.1 Reversals**

36 A reversal is described as an accidental release of injected CO₂ from the deep saline aquifer.
37 Sources and Sinks in this protocol provide mechanisms to quantify reversals (see Section 3.1)
38 and Appendix D provides a method for accounting for uncertainty arising out of the
39 measurement and monitoring plan. Please refer to Alberta Environment for guidance on liability
40 of reversals.
41
42

References

1
2
3 Alberta Environment (AENV). Alberta Offset System Quantification Protocol for Enhanced Oil
4 Recovery. Version 1, October 2007. <http://environment.gov.ab.ca/info/library/7910.pdf>

5
6 Alberta Environment (AENV). Alberta Offset System Quantification Protocol for Acid Gas
7 Injection Projects. May 2008. <http://environment.gov.ab.ca/info/library/7961.pdf>

8
9 American Carbon Registry (ACR). Greenhouse Gas Emission Reduction Protocol for the Monell
10 Enhanced Oil Recovery (EOR) Project, Anadarko Petroleum Corporation. August 2004,
11 Revision 3. [http://www.americancarbonregistry.org/carbon-registry/projects/monell-enhanced-](http://www.americancarbonregistry.org/carbon-registry/projects/monell-enhanced-oil-recovery-project/Monell%20GHG%20Protocol%20081004R3_020909.pdf/at_download/file)
12 [oil-recovery-project/Monell%20GHG%20Protocol%20081004R3_020909.pdf/at_download/file](http://www.americancarbonregistry.org/carbon-registry/projects/monell-enhanced-oil-recovery-project/Monell%20GHG%20Protocol%20081004R3_020909.pdf/at_download/file)

13
14 American Carbon Registry (ACR). Greenhouse Gas Emission Reduction Protocol for the Salt
15 Creek Enhanced Oil Recovery (EOR) Project Howell Petroleum Corporation. August 2004,
16 Revision 4. [http://www.americancarbonregistry.org/carbon-registry/projects/salt-creek-](http://www.americancarbonregistry.org/carbon-registry/projects/salt-creek-enhanced-oil-recovery-project/Salt%20Creek%20GHG%20Protocol%20081004R4_020909.pdf/at_download/file)
17 [enhanced-oil-recovery](http://www.americancarbonregistry.org/carbon-registry/projects/salt-creek-enhanced-oil-recovery-project/Salt%20Creek%20GHG%20Protocol%20081004R4_020909.pdf/at_download/file)
18 [project/Salt%20Creek%20GHG%20Protocol%20081004R4_020909.pdf/at_download/file](http://www.americancarbonregistry.org/carbon-registry/projects/salt-creek-enhanced-oil-recovery-project/Salt%20Creek%20GHG%20Protocol%20081004R4_020909.pdf/at_download/file)

19
20 American Carbon Registry (ACR). Blue Source's Greenhouse Gas Emission Reduction Protocol
21 for Petro Source's Capture of Vent-Stack CO₂ in Combination with Enhanced Oil Recovery
22 Operations. December 2006. [http://www.americancarbonregistry.org/carbon-](http://www.americancarbonregistry.org/carbon-registry/projects/petrosource-eor-carbon-sequestration-project/PetroSourceProtocol-jul04-06-final.pdf/at_download/file)
23 [registry/projects/petrosource-eor-carbon-sequestration-project/PetroSourceProtocol-jul04-06-](http://www.americancarbonregistry.org/carbon-registry/projects/petrosource-eor-carbon-sequestration-project/PetroSourceProtocol-jul04-06-final.pdf/at_download/file)
24 [final.pdf/at_download/file](http://www.americancarbonregistry.org/carbon-registry/projects/petrosource-eor-carbon-sequestration-project/PetroSourceProtocol-jul04-06-final.pdf/at_download/file)

25
26 American Carbon Registry (ACR). Blue Source's Greenhouse Gas Emission Reduction Protocol
27 for SandRidge CO₂ LLC's capture of Vent-Stack CO₂ at Pikes Peak in Combination with
28 Enhanced Oil Recovery Operations. December 2008.
29 [http://www.americancarbonregistry.org/carbon-registry/projects/pikes-peak-eor-carbon-](http://www.americancarbonregistry.org/carbon-registry/projects/pikes-peak-eor-carbon-sequestration-project/PetroSource%20PP%20protocol.pdf/at_download/file)
30 [sequestration-project/PetroSource%20PP%20protocol.pdf/at_download/file](http://www.americancarbonregistry.org/carbon-registry/projects/pikes-peak-eor-carbon-sequestration-project/PetroSource%20PP%20protocol.pdf/at_download/file)

31
32 American Carbon Registry (ACR). Blue Source's Emission Reduction Protocol for Merit
33 Energy's CO₂ Geologic Sequestration through Enhanced Oil Recovery Operations. July 2008.
34 [http://www.americancarbonregistry.org/carbon-registry/projects/merit-energy-eor-carbon-](http://www.americancarbonregistry.org/carbon-registry/projects/merit-energy-eor-carbon-sequestration-project/Merit%20Energy%20Protocol%202002.pdf/at_download/file)
35 [sequestration-project/Merit%20Energy%20Protocol%202002.pdf/at_download/file](http://www.americancarbonregistry.org/carbon-registry/projects/merit-energy-eor-carbon-sequestration-project/Merit%20Energy%20Protocol%202002.pdf/at_download/file)

36
37 American Petroleum Institute (API) - International Petroleum Industry Environmental
38 Conservation Association (IPIECA). Oil and Natural Gas Industry Guidelines for Greenhouse
39 Gas Reduction Projects. Part II: Carbon Capture and Geological Storage Emission Reduction
40 Family. June 2007. http://www.ipieca.org/system/files/publications/CCS-FINAL_merged.pdf

41
42 Blue Source Canada ULC. Draft GHG Quantification Methodology for Carbon Capture and
43 Storage Projects. Prepared on behalf of ICO₂N and presented to Alberta Environment April
44 2009.

- 1 Blue Source Canada ULC. Draft Carbon Capture and Geologic Storage Emission Reduction
2 Quantification Methodology (September 2010, Version 5). Prepared for the North American
3 Carbon Capture and Storage Association (NACCSA).
4
- 5 Clean Development Mechanism (CDM). NM0167: Recovery of anthropogenic CO₂ from large
6 industrial GHG emission sources¹ and its storage in an oil reservoir. Version 1, January 2005.
7 <http://cdm.unfccc.int/UserManagement/FileStorage/AM6CJE7R0VH1DPTZ79LW4QQ26ZTQ0>
8 [4](#)
9
- 10 Clean Development Mechanism (CDM). NM0168: The capture of CO₂ from natural gas
11 processing plants and liquefied natural gas (LNG) plants and its storage in underground aquifers
12 or abandoned oil / gas reservoirs. Version 1, January 2006.
13 <http://cdm.unfccc.int/UserManagement/FileStorage/VK115G0CSRZYB8JCSMF1420747JTS7>
14
- 15 Clean Development Mechanism (CDM). Capture of CO₂ from the front-end of integrated Gas-
16 to-Liquid (GTL) plants, transport via pipeline and long-term containment in appropriately
17 selected and well-managed geological storage complexes. 2009. Shell.
18
- 19 Canadian Standards Association (CSA) GHG Reductions Registry. Greenhouse Gas Emission
20 Reduction Protocol for the Monell Enhanced Oil Recovery (EOR) Project. Anadarko E&P
21 Company LP. August, 2004. http://www.ghgregistries.ca/files/projects/prj_6265_692.pdf
22
- 23 Canadian Standards Association (CSA) GHG Reductions Registry. Greenhouse Gas Emission
24 Reduction Protocol for the Salt Creek Enhanced Oil Recovery (EOR) Project. Howell Petroleum
25 Corporation. August, 2004. http://www.ghgregistries.ca/files/projects/prj_6228_693.pdf
26
- 27 Canadian Standards Association (CSA) GHG Reductions Registry. Protocol for Tracking
28 Greenhouse Gas Emission Reductions from the Hays Enhanced Oil Recovery (EOR) Project.
29 Anadarko Canada Resources. December 2005.
30 http://www.ghgregistries.ca/files/projects/prj_6527_697.pdf
31
- 32 Canadian Standards Association (CSA) GHG Reductions Registry. Verification of Blue Source
33 Emission Reduction Credits Created from Denbury Resources' Geologic Sequestration Project.
34 Denbury Resources. April 2004. http://www.ghgregistries.ca/files/projects/prj_4021_739.pdf
35
- 36 Canadian Standards Association (CSA) GHG Reductions Registry. Offset Project Plan CO₂
37 Capture from Prentiss² for EOR MEGlobal Canada Inc. January 2009.
38 http://www.ghgregistries.ca/files/projects/prj_9923_841.pdf
39
- 40 Canadian Standards Association (CSA) GHG Reductions Registry. Offset Project Plan CO₂
41 Capture from Prentiss¹ for EOR MEGlobal Canada Inc. January 2009.
42 http://www.ghgregistries.ca/files/projects/prj_3333_840.pdf
43
- 44 Canadian Standards Association (CSA) GHG Reductions Registry. Emission Reduction Credit
45 (ERC) Creation Report for PetroSource's Capture of Vent-Stack CO₂ in Combination With

- 1 Enhanced Oil Recovery Operations. March 2001.
2 http://www.ghgregistries.ca/reductions/rer_masterprojectdetails_e.cfm?pid=669
3
- 4 Environment Canada, Fuel Combustion Emission Factors, 2011, <http://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=AC2B7641-1#section1>
5
6
- 7 Environmental Protection Agency (EPA). Proposed Rule Subpart RR–Carbon Dioxide Injection
8 and Geologic Sequestration. March, 2010.
9 <http://www.regulations.gov/search/Regs/contentStreamer?objectId=0900006480ad5a76&disposition=attachment&contentType=pdf>
10
11
- 12 Environmental Protection Agency (EPA). Proposed rule for Federal Requirements Under the
13 Underground Injection Control (UIC) Program for Carbon Dioxide (CO₂) Geologic
14 Sequestration (GS) Wells. July, 2008. <http://www.epa.gov/fedrgstr/EPA-WATER/2008/July/Day-25/w16626.pdf>
15
16
- 17 Interstate Oil and Gas Compact Commissions (IOGCC). Carbon Capture and Storage – A
18 Regulatory Framework for the States. IOGCC CO₂ Geological Sequestration Task Force, Kevin
19 Bliss, editor. Prepared under DOE Contract No. DE-FC26-03NT41994, January 2005.
20
- 21 International Standards Organization. ISO 14064-2:2006 Specification with Guidance at the
22 Project Level for Quantification, Monitoring and Reporting of GHG Emission Reductions or
23 Removal Enhancements.
24
- 25 Kostiuk, Larry. Johnson, Matthew, and Thomas, Glen. University of Alberta Flare Research
26 Project. Final Report September 2004. University of Alberta.
27
- 28 World Resources Institute (WRI) and the World Business Council Development (WBCSD).
29 Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard (Revised Edition).
30 March 2004. http://pdf.wri.org/ghg_protocol_2004.pdf
31
- 32 World Resources Institute. (WRI). Guidelines for Carbon Dioxide Capture, Transport, and
33 Storage. October, 2008. http://pdf.wri.org/ccs_guidelines.pdf
34
35
36
37
38
39
40
41
42

1
2
3
4
5
6
7
8
9
10
11
12

APPENDIX A
Emission Factors

DRAFT

1 **Table A1: Combustion Emission Factors for Gasoline and Diesel**¹³

Fuel	Fuel Combustion Emission Factors (kg GHG/ litre fuel)		
	CO ₂	CH ₄	N ₂ O
Gasoline	2.289	0.00056	0.00066
Diesel	2.663	0.00015	0.00022

2
3 **Table A2: Emission Factors for Natural Gas and NGL's**
4

Source	Emission Factors		
	CO ₂	CH ₄	N ₂ O
	g/m ³	g/m ³	g/m ³
Natural Gas			
Electric Utilities	1891	0.49	0.049
Industrial	1891	0.037	0.033
Producer Consumption	2389	6.5	0.06
Pipelines	1891	1.9	0.05
Cement	1891	0.037	0.034
Manufacturing Industries	1891	0.037	0.033
Residential, Construction, Commercial/Institutional, Agriculture	1891	0.037	0.035
	g/L	g/L	g/L
Propane			
Residential	1510	0.027	0.108
All Other Uses	1510	0.024	0.108
Ethane	976	N/A	N/A
Butane	1730	0.024	0.108

5
6 The following emission factors are used for fuel extraction and production.
78 **Table A3: Emission Intensity of Fuel Extraction and Production (Diesel and Gasoline)**¹⁴
9

Diesel		
Production		
Emissions Factor (CO ₂)	0.138	kg CO ₂ per Litre
Emissions Factor (CH ₄)	0.0109	kg CH ₄ per Litre
Emissions Factor (N ₂ O)	0.000004	kg N ₂ O per Litre
Natural Gas		
Extraction		
Emissions Factor (CO ₂)	0.043	kg CO ₂ per m ³
Emissions Factor (CH ₄)	0.0023	kg CH ₄ per m ³
Emissions Factor (N ₂ O)	0.000004	kg N ₂ O per m ³
Processing		
Emissions Factor (CO ₂)	0.090	kg CO ₂ per m ³
Emissions Factor (CH ₄)	0.0003	kg CH ₄ per m ³
Emissions Factor (N ₂ O)	0.000003	kg N ₂ O per m ³

¹³ Environment Canada, Fuel Combustion Emission Factors¹⁴ Emissions by the Upstream Oil and Gas Industry. CAPP. 2004.

Gasoline Production		
Emissions Factor (CO ₂)	0.138	kg CO ₂ per Litre
Emissions Factor (CH ₄)	0.0109	kg CH ₄ per Litre
Emissions Factor (N ₂ O)	0.000004	kg N ₂ O per Litre

1
2

Table A4: Emission Intensity of Grid Electricity in Alberta¹⁵

Type	GHG Intensity (t CO ₂ e/MWh)
Emission Factor for Using Grid Electricity	0.88
Emission Factor for Displacing Grid Electricity with Renewable Electricity	0.65

3
4

DRAFT

¹⁵ Refer to the Alberta Environment Technical Guidance for Offset Protocol Developers document to confirm that the most up to date grid intensity emission factor is being used. <http://environment.gov.ab.ca/info/library/8331.pdf>

1
2
3
4
5
6
7
8
9
10
11
12

APPENDIX B
Specified Gases and Global Warming Potential

DRAFT

1
2**Table B1: Specified Gases and Global Warming Potential**

Global Warming Potential (100 year time horizon)	Specified Gas
1	Carbon dioxide
21	Methane
310	Nitrous oxide
11700	HFC-23
650	HFC-32
150	HFC-41
1300	HFC-43-10mee
2800	HFC-125
1000	HFC-134
1300	HFC-134a
140	HFC-152a
300	HFC-143
3800	HFC-143a
2900	HFC-227ea
6300	HFC-236fa
560	HFC-245ca
23900	Sulphur hexafluoride
6500	Perfluoromethane
9200	Perfluoroethane
7000	Perfluoropropane
7400	Perfluorobutane

3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31
32
33
34
35

APPENDIX C
CO₂ Injection by Multiple Proponents

DRAFT

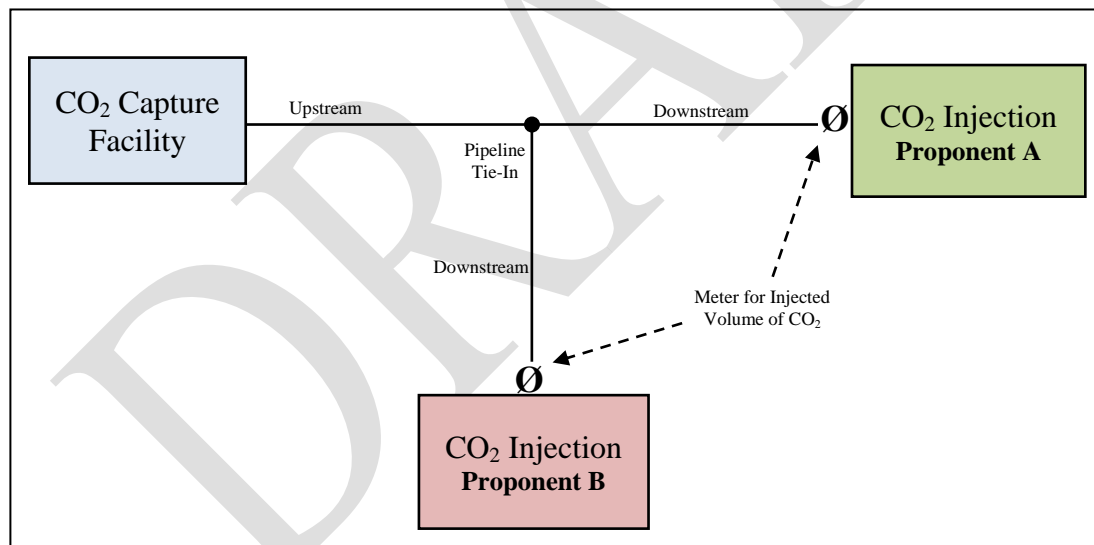
1 Guidance for the Injection of CO₂ by Multiple Proponents

2
3 The following provides guidance for projects in which the CO₂ is being transported to carbon
4 capture and storage activities as well as third party injection activities (EOR or permanent
5 storage). Project proponents must demonstrate that all sources and sinks are properly accounted
6 for and must satisfy the principle that all project emissions must be accounted for once. In the
7 case of a complex CO₂ system or network, the emissions from that network would have to be
8 accounted for in the project condition. A system emission factor would be applied whereby the
9 project emissions are prorated proportionally across each project proponent participating in the
10 network. The proponents would have to justify the method and values used to determine the
11 system emission factor during the project, and could initiate a protocol review by Alberta
12 Environment.

14 Upstream Project Emissions:

15 Upstream project emissions are described as any emission occurring before the pipeline splits to
16 deliver the CO₂ to the multiple proponents. Upstream project emissions are characterized by all
17 the emissions associated with capturing CO₂ and refer to SS P4-P9 and P12-P15. Figure C1,
18 below, provides a schematic to illustrate the process flow for injection of CO₂ by multiple
19 proponents.

21 **Figure C1: Process Flow Diagram for the Injection of CO₂ by Multiple Proponents**



39 To properly account for all upstream project emissions, project proponents must **proportionally**
40 attribute all upstream project emissions across all proponents. Each proponent would deduct the
41 associated upstream project emission, which is proportional to the amount of CO₂ injected, from
42 their total emission reduction. This would result in an equal distribution of the associated
43 upstream project emissions depending on the amount of CO₂ injected by each proponent. For
44 example:

- 45 • If proponent A injects 60% of the captured CO₂ and proponent B injects the other 40%,
46 then the upstream project emissions associated with the captured CO₂ would be ascribed

1 proportionally to each proponent. In this example, proponent A would deduct 60% of the
2 upstream project emissions from proponent A's total emission reductions. Proponent B
3 would deduct 40% of the upstream project emissions from proponent B's total emission
4 reductions.

5 **Downstream Project Emissions:**

6 Downstream project emissions are described as any emission occurring after the pipeline splits to
7 deliver the CO₂ to the multiple proponents. Each proponent must account of their individual
8 downstream project emissions associated with injecting the CO₂.
9

DRAFT

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23

APPENDIX D
**Guidance for Estimating Emissions from Subsurface
Equipment and Deep Saline Aquifer**

DRAFT

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25

Guidance for Estimating Emissions from Subsurface Equipment and Deep Saline Aquifer

The amount of emissions leaked from the subsurface equipment or deep saline aquifer to atmosphere for each of the leakage events should be estimated with a maximum overall uncertainty over the reporting period of $\pm 7.5\%$. If the amount of emissions leaked from the subsurface equipment or deep saline aquifer to atmosphere for each identified leakage event can be estimated within an uncertainty range of $\pm 7.5\%$, then the estimated figure is reported and utilized. In case the overall uncertainty of the applied quantification approach exceeds $\pm 7.5\%$, an adjustment shall be applied, as follows:

$$CO_{2, \text{Reported}} [\text{t CO}_2] = CO_{2, \text{Quantified}} [\text{t CO}_2] * (1 + (\text{Uncertainty}_{\text{System}} [\%]/100) - 0.075)$$

Where,

$CO_{2, \text{Reported}}$: Amount of CO₂ to be included into the annual emission report with regards to the leakage event in question;

$CO_{2, \text{Quantified}}$: Amount of CO₂ determined through the used quantification approach for the leakage event in question;

$\text{Uncertainty}_{\text{System}}$: The level of uncertainty which is associated to the quantification approach used for the leakage event in question.