METHODOLOGY FOR THE QUANTIFICATION, MONITORING, REPORTING AND VERIFICATION OF GREENHOUSE GAS EMISSION REDUCTIONS AND REMOVALS FROM

CARBON CAPTURE AND STORAGE PROJECTS

VERSION 2.0

May 2026

ACR AT WINROCK INTERNATIONAL

METHODOLOGY FOR THE QUANTIFICATION, MONITORING, REPORTING AND VERIFICATION OF GREENHOUSE GAS EMISSION REDUCTIONS AND REMOVALS FROM

CARBON CAPTURE AND STORAGE PROJECTS

VERSION 2.0

May 2026

ACR[SM]

OFFICE ADDRESS
Environmental Resources Trust, LLC
325 W Capitol Ave, Suite 350
Little Rock, Arkansas 72201 USA
ph +1 571 402 4235

ACR@winrock.org
acrcarbon.org

ABOUT ACR[SM]

ACR is a leading global carbon crediting program operating in regulated and voluntary carbon markets. Founded in 1996 as the first private voluntary greenhouse gas (GHG) registry in the world, ACR creates confidence in the integrity of carbon markets to catalyze transformational climate results. ACR ensures carbon credit quality through the development of environmentally rigorous, science-based standards and methodologies as well as oversight of GHG Project verification, registration, and credit issuance and retirement reporting through its transparent registry system. ACR is governed by Environmental Resources Trust LLC, a wholly owned nonprofit subsidiary of Winrock International.

Acknowledgements

This version update was authored by ACR. The methodology was originally developed with Blue Strategies.

Contents

FIGURES

TABLES

EQUATIONS

Acronyms & Abbreviations

°C	degrees Celsius
°F	degrees Fahrenheit
AoR	area of review
atm	standard atmosphere
bbl	barrel
BECCS	bioenergy with carbon capture and storage
BiCRS	biomass with carbon removal and storage
CCS	carbon capture and storage
CCUS	carbon capture, utilization, and storage
CH_4	methane
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CO_2-EOR	carbon dioxide-enhanced oil recovery
DAC	direct air capture
EOR	enhanced oil recovery
ERRs	emission reductions and removals
ERT	Emission Reduction Ton
ft^3	cubic feet
g	gram
GWP	global warming potential

GHG	greenhouse gas
GT	gigatonne
K	Kelvin
kg	kilogram
kWh	kilowatt hour
lb.	pound
m^3	cubic meter
min	minute
MT	metric ton
MMcf	million cubic feet
MMscf	million standard cubic feet
MMT	million metric tons
MRV	monitoring, reporting, and verification
MWh	megawatt-hour
N_2O	nitrous oxide
scf	standard cubic foot
SSRs	sources, sinks, and reservoirs
USDW	underground source of drinking water

1 Methodology Description

This science-based methodology provides the quantification and accounting framework for the creation of carbon credits from carbon capture and storage (CCS) projects, including procedures for determining eligibility, assessing additionality, and quantifying, monitoring, reporting, and verifying greenhouse gas (GHG) emission reductions and removals.

CCS involves capturing carbon dioxide (CO_2) that would otherwise be released into the atmosphere or is already present in atmospheric concentrations and injecting it deep underground for permanent storage in geologic reservoirs. CCS technology emerged within the oil and gas sectors, utilizing CO_2 mined from underground sources in enhanced oil recovery (EOR), which also results in the permanent underground storage of some of the injected CO_2 (IEA, 2015). The practice of safely transporting and storing CO_2 underground through EOR (also called CO_2-EOR) has been successfully implemented for over 50 years in North America, particularly in jurisdictions such as Texas, Saskatchewan, and Alberta, demonstrating the long-term viability and safety of CCS operations (IEA, 2015).

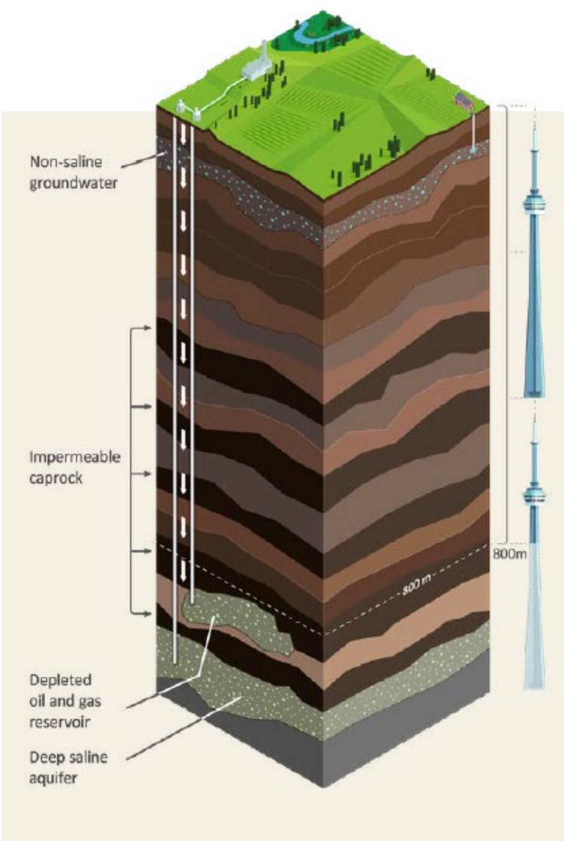
Starting in the early 2000s, increased attention to climate change and the need to decrease GHG emissions prompted broader applications of the underground injection and storage technology to permanently store CO_2 underground. This included identifying large sources of fuel-derived CO_2 such as power generation, cement production,[1] steel manufacturing, and chemical processing; and developing and refining CO_2 capture methods (Global CCS Institute, 2024). Researchers expanded their focus beyond oil and gas fields to assess the suitability of deep saline geologic reservoirs for CO_2 storage. These reservoirs consist of porous and permeable rocks, such as sandstone, that are capable of absorbing and retaining large volumes of injected CO_2. When these rocks are at depths conducive to permanent storage of CO_2 (generally >800 meters), they contain saline (salty) water. Critically, when these reservoirs are overlain by one or more impermeable layers (e.g., shale, clay), these cap rocks act as seals that prevent the migration of CO_2 and ensure long-term containment (Bruant et al., 2002) (refer to Figure 1).[2] Saline reservoirs are especially promising because they are widely distributed and

[1] In addition to utilizing GHG emissions-intense fossil fuels like coal, cement production releases large amounts of CO_2 due to the decomposition of calcium carbonate, which is required to produce clinker.

[2] CO_2 becomes supercritical below approximately 800 m depth. When porous sedimentary formations such as sandstone are located at depths greater than 800 meters, the conditions allow CO_2 to exist as a supercritical fluid. These formations are typically saturated with saline water and can absorb and retain large volumes of injected CO_2, making them ideal for long-term geological storage (Bruant et al., 2002). Supercritical fluids exist at a temperature and pressure above their critical point, meaning that they are above the point at which distinct liquid and gas phases exist but below the point at which pressure compresses the mass into a solid. This supercritical state allows the liquid to effuse through porous solids like a gas and dissolve in liquids.

can trap CO_2 through multiple mechanisms, including structural, residual mineralization, solubility, and mineral trapping[3] (Bruant et al., 2002; IPCC, 2023; U.S. DOE, 2021).

Figure 1: Schematic Diagram of a Typical CO_2 Storage Process in a Geologic Storage Reservoir (non-EOR)[4]



Today, CCS is increasingly recognized as a technology that is essential for achieving climate commitments, meeting near- and long-term emission reduction targets, and enabling the transition to sustainable, net-zero-carbon economies. By addressing industrial and electricity generation

[3] Mineral trapping is the process by which injected CO_2 reacts with host rock minerals to form stable carbonate solids, providing permanent geologic storage. Residual mineralization refers specifically to the continued formation of these carbonates after injection has ended, as dissolved CO_2 slowly reacts over time. The key difference lies in timing—mineral trapping includes all mineralization, while residual mineralization occurs passively post-injection (Bruant et al., 2002).

[4] Image from Ontario Ministry of Natural Resources (2025)

emissions and atmospheric CO_2, CCS provides the flexible infrastructure needed to mitigate climate change impacts across multiple sectors and timelines (IPCC, 2022).

Carbon capture and storage[5] is a technology-based solution for addressing global climate change and generally consists of the following component processes:

- Capture of carbon dioxide (CO2) molecules from either
  - Electricity generation or industrial process point source emissions before they enter the atmosphere; or
  - The atmosphere, through carbon dioxide removal (CDR);
- Transport of the captured CO2; and
- Safe, permanent storage of the CO2 in a geologic storage reservoir.

Estimates of CO_2 storage capacity vary widely. The Intergovernmental Panel on Climate Change's (IPCC's) Sixth Assessment Report (2023) estimates the global technical geological storage capacity to be approximately 1,000 gigatonnes (billion metric tons, or GT) CO_2, based on well-characterized and accessible sites, primarily deep saline reservoirs and depleted oil and gas reservoirs (IPCC, 2023). In North America, U.S. DOE estimated the combined geological CO_2 storage capacity of the U.S. and Canada as between ~2500 to over 20,000 $GTCO_2$, with the highest potential in saline reservoirs (U.S. DOE NETL, 2015). The IPCC projects that 350–1,200 $GTCO_2$ must be captured and geologically stored this century to achieve the 1.5 °C target (IPCC, 2023) and the Global CCS Institute states that CCS is an essential component in all global modeled pathways that limit warming to 1.5 °C (Global CCS Institute, 2024). Whichever storage capacity estimate is correct, there is significant storage capacity and a need to avoid further emission of CO_2 and remove CO_2 already in the atmosphere.

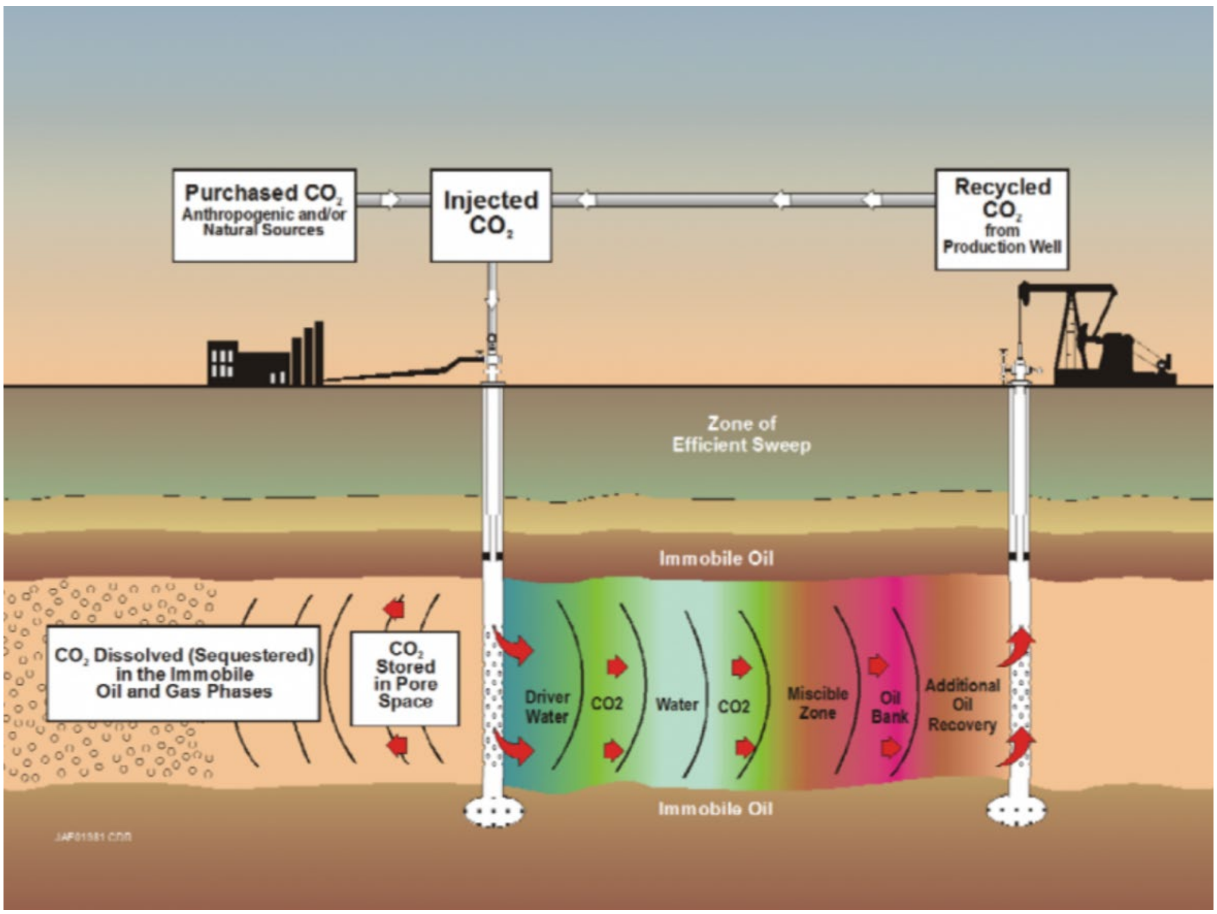
Removal of atmospheric CO_2 occurs naturally through photosynthesis, which turns CO_2 into plant carbon (e.g., biomass). This biomass can be used to create energy and the CO_2 emitted through energy creation can be captured and stored in geologic storage reservoirs. This can be categorized as bioenergy with carbon capture and storage (BECCS), which captures emissions from burning biogas or other biomass for energy, or biomass with carbon removal and storage (BiCRS), which sequesters CO_2 from biomass processing or decomposition. A more advanced technology known as direct air capture (DAC) uses chemical and physical processes to extract CO_2 directly from ambient air; when paired with storage, it can result in removal of CO_2 from the atmosphere. These carbon dioxide removal (CDR) pathways complement traditional CCS and expand its role from reducing emissions at the source to actively drawing down atmospheric CO_2 (IPCC, 2023).

CO_2-EOR is based on the concept of miscible or immiscible displacement of oil by CO_2. A typical CO_2-EOR flood operation is shown in Figure 2. In this process, CO_2 is generally injected at a pressure that

[5] Also known as "carbon capture and sequestration."

results in total or partial miscibility with the oil in the reservoir and injected into injection wells that are strategically across the areal extent of the reservoir. The injected CO_2 enters the reservoir and moves through the pore spaces of the rock, encountering residual droplets of crude oil, becoming miscible with the oil, and forming a concentrated oil bank that is swept towards the producing wells, where oil mixed with water and gas is pumped to the surface, where it flows to a centralized collection facility. The produced fluid containing oil, water, gas, and CO_2 is separated, and any produced CO_2 is re-compressed and re-injected along with additional volumes of new CO_2. The separated produced water is treated and re-injected, often alternating with CO_2 injection, in a water-alternating-gas process.

Figure 2: Schematic Diagram of a Typical EOR Process Using CO_2 and Water in a Water-Alternating-Gas Process[6]



The CO_2 produced with the oil at production wells is recovered and reinjected into the formation. Of the remaining CO_2 that is not produced, some of it will be trapped or mineralized in the rock's pore

[6] Image from Kuuskraa et al. (2013). Reproduced with permission.

space, some will become dissolved in the formation brine, and the remainder will migrate to the upper part of the oil reservoir since CO_2 is lighter than the oil and water in the formation. All the CO_2 that remains in the oil reservoir is permanently trapped (stored).

Carbon market finance can offset the substantial design, capital, and operational costs of CO_2 capture, transport, and storage and help to incentivize the use of anthropogenic CO_2 over geologic CO_2, the latter of which not only has no benefit to addressing climate change, but in fact contributes to it. Notably, the IPCC's Sixth Assessment Report Synthesis Report (2023) states that appropriate carbon pricing or credit systems are vital to drive investment in CCS. Expanding market-based recognition of CCS will enhance financial viability, drive innovation, enable deep decarbonization across industrial sectors, and support global emission reduction strategies (IPCC, 2023).

Additionality requirements ensure that GHG emission reductions and removals are in excess of what would have occurred under current laws and regulations, current industry practices, and without carbon market incentives. Projects Proponents have two pathways to establish additionality under this methodology as further described in Section 3. The Project Proponent can demonstrate that 1) the project is in surplus to existing law, regulation, or other regulatory framework that mandates the project activity and that the project meets or exceeds the benchmark performance standard set in this methodology or 2) assess the project against the three-pronged additionality test, requiring the project activity to exceed existing law, regulation, or other regulatory framework that mandates the project activity, to exceed common practice in the sector and geographic region, and to overcome a financial implementation barrier.

There are different approaches to baseline determination depending on the project type and any applicable emission limits as described further in Sections 5 and 6.1. For projects where CO_2 is sourced from point source industrial processes and electricity generation, the baseline scenario represents a below-business-as-usual release of GHGs to the atmosphere from the operation of existing or new facilities which would occur in the absence of the project activity to capture and permanently store the CO_2. This is true whether these CO_2 sources produce CO_2 from fossil fuels or sustainable biomass. For DAC projects, the baseline scenario is the CO_2 captured by the project, which would have remained in the atmosphere in the absence of the project activity to capture the CO_2.

Emission Reduction Tons (ERTs), denominated in metric tons of CO_2e, are issued for the Total GHG Emission Reductions and Removals, as quantified in this methodology, equal to the baseline scenario less emissions from project implementation.

There is no activity-shifting leakage or market leakage associated with this project type (see Section 6.4). Uncertainty is addressed throughout the methodology in line with the principle of conservativeness, so no uncertainty deduction is applied (see Section 6.5). Emission reduction credits are issued for the reduction of industrial process emissions to the atmosphere and removal credits are issued for CO_2 removed from the atmosphere through CDR (see Section 6.3).

Projects must have effective reversal risk mitigation measures in place to avoid and compensate for any reversal. Risk mitigation measures include a legally binding ACR CCS Project Reversal Risk Mitigation Contract and Reserve Account contributions or an alternative risk mitigation mechanism approved by ACR (see Section 9). Reversals are mitigated through the Methodology's eligibility and monitoring, reporting, and verification requirements, including monitoring during the post-injection period to demonstrate that plume stabilization has been achieved (see Section 7.3.12). Legally binding agreements prevent, provide for the discovery of, and ensure compensation for activity occurring on the surface or in the subsurface that may result in a reversal.

2 Eligibility Conditions

In addition to satisfying the ACR program requirements, project activities must satisfy all of the following eligibility conditions:

I. The project must be in the United States (U.S.), U.S. territories, or Canada, including the jurisdictional waters (i.e., the Exclusive Economic Zone) of the United States and Canada. This requirement relates to the following segments of the project: capture, processing & compression; transport; and injection, storage, monitoring & hydrocarbon production and onsite processing).

II. CCS activities are safeguarded by regulatory frameworks consistent with Table 3 of Section 11.1 of the Regulatory Scheme CORSIA Eligibility Requirements for Geological CCS Projects (ICAO, 2025) or are verified to demonstrate conformance with the same requirements.

III. Capture, transport and permanently store CO_2 in alignment with the eligible activities in Table 1. CO_2 storage must occur at a new geologic storage reservoir (i.e., be newly storing CO_2 from source(s) listed in Table 1). CO_2-EOR projects moving from geologically sourced CO_2 to one of the sources listed in Table 1 are eligible for the periods noted in Section 4.3.

IV. Demonstrate that the project is additional to what would have occurred under a business-as-usual scenario, current laws and regulations, current industry practices, and without carbon market incentives per Section 3.

V. CO_2 captured from natural gas processing facilities that are CO_2 sources must be processing gas from oil and gas reservoir(s) with (a) historical (i.e., pre-2021) production *or* (b) where the natural gas production is demonstrated to be financially viable in the absence of carbon credits. The latter demonstration is only required when the historical production requirement is not met. If the CO_2 captured by a natural gas processing facility during a Reporting Period is derived from natural gas from different reservoirs—some of which have historical production (as defined by 2.V.(a)) and some of which do not—the amount of gas from reservoirs in each category (historical production, without historical production) shall be metered and the financial viability demonstration shall be performed for the gas from the reservoir(s) *without* historical production. Once assessment is completed and all applicable reservoirs are deemed eligible, the facility can stop metering. However, if the processing facility that is a CO_2 source processes gas from a reservoir that does not meet these eligibility criteria, metering must be ongoing and any captured CO_2 from that reservoir must be excluded. Each time gas from a new reservoir is processed at the facility and the associated CO_2 captured, a financial viability demonstration must be performed. To pass the financial viability demonstration, the answers to the following three questions must be "no":
   - Does the natural gas production face capital constraints that carbon revenues could address?

- Is carbon funding reasonably expected to incentivize natural gas production? and
- Are carbon revenues a key element to maintaining the ongoing economic viability of natural gas production during the CCS project?

VI. Wells shall be permitted[7] under applicable underground injection regulations. In the U.S., this means the wells must be permitted as either Class II wells or Class VI wells under the U.S. Environmental Protection Agency's (EPA's) Underground Injection Control (UIC) Program (U.S. EPA, 2010c). In Canada, wells shall be permitted under federal or provincial regulatory frameworks. Projects shall also meet all requirements outlined in Section 7 of this Methodology. Refer to list of applicable regulations available from ACR's CCS Methodology website.

VII. Utilize a monitoring, reporting, and verification plan as required by Section 7 of this Methodology.

VIII. Demonstrate clear and uncontested rights to the storage reservoir pore space as described in Section 8.2 and that the Project Proponent has entered into a Reversal Risk Mitigation Contract with ACR as described in Section 9.

IX. Demonstrate approval (through legal agreements) from the surface owner(s) for the Project Proponent to access the surface land for the duration of the Minimum Project Term to conduct post-injection monitoring and, if necessary, remediation, as described in Section 8.3.

X. Transportation pipelines (if utilized for the CCS project) must be designed, permitted, and operated in compliance with applicable federal, state/provincial, and international regulations.

XI. Projects utilizing biomass that generate the captured CO_2 must use sustainable biomass (as defined in Appendix D of this Methodology) grown, produced, harvested, or otherwise sourced from within an eligible jurisdiction.

XII. Assess compatibility of the project activities with transition to net zero and demonstrate compatibility in the GHG Project Plan with net zero emissions in the host country.

[7] Any permit transfers require regulatory notification and approval using forms prescribed by the jurisdiction (e.g., EPA Form 7520-12), with the final versions of permits in place at any time in the Reporting Period provided to the VVB and described in the MRV Plan.

Eligible project activities include the CO_2 source(s), methods of transport, and permanent storage in eligible geologic storage reservoirs, as outlined in Table 1 below.

Table 1: Eligible CCS Project Components

CCS PROJECT COMPONENT	ELIGIBLE PROJECT ACTIVITIES
CO_2 SOURCES	Capture of CO_2 emissions from electrical power generation and industrial processes, including from fossil fuels, and from combustion/use of methane captured from landfills and from livestock and wastewater treatment anaerobic digestion.
	Capture of emissions from electrical power generation and industrial processes using sustainable biomass sources in accordance with Appendix D (i.e., BiCRS, BECCS).
	Capture of atmospheric CO_2 via direct air capture technology.
METHODS OF TRANSPORT	Transport of CO_2 via pipelines, rail lines, roads, maritime ships, barges, or intermodal transport.
STORAGE RESERVOIRS	Storage in geologic storage reservoirs, including saline reservoirs and depleted oil or gas reservoirs, and producing oil reservoirs, including enhanced oil recovery in limited locations.

The following are ineligible under this Methodology:

- CO_2 sourced from natural carbon dioxide-bearing formations (i.e., geologic CO2 pools).7F CO_2-EOR projects that inject CO_2 extracted from large underground geologic domes simply transfer CO_2 from one geologic reservoir to another, which has no benefit to atmospheric CO_2 concentration and climate change.
- In-situ carbon mineralization beyond that which happens as part of the geologic CO2 storage processes described in this Methodology, ex-situ carbon mineralization, and enhanced weathering.
- Imported sustainable biomass fuels or feedstocks sourced from jurisdictions outside of the approved jurisdictions.
- Injection in locations where faults, fractures, structure, or other geologic factors indicate that isolation of the authorized injection or disposal zone is jeopardized.
- Injection where geological conditions suggest potential for induced seismicity that could endanger public safety or environmental resources.

- Injection in geologic storage reservoirs that lack adequate capacity or injectivity for the proposed operation.
- Storage in basaltic or coal formations. Storage in these types of reservoirs involves in-situ mineralization.
- Use of artificial or engineered containment systems (e.g., buried tanks, pipelines, man-made enclosures). (Only natural subsurface geological formations meeting all regulatory requirements are eligible.)

3 Additionality Assessment

The climate benefits of GHG Projects developed under this methodology are additional to what would have occurred under a business-as-usual scenario, current laws and regulations, current industry practices, and without carbon market incentives. To qualify as additional, the project must pass a regulatory surplus test and exceed a performance standard or pass the three-pronged additionality test, including the regulatory surplus test set forth below. Additionality must be demonstrated and validated prior to the project's first credit issuance.

3.1 Regulatory Surplus Test

To pass the regulatory surplus test, the Project Proponent must establish regulatory additionality by demonstrating that there is no existing law, regulation, statute, legal ruling, or any other regulatory framework that directly mandates the project activity or effectively requires the GHG emission reductions and/or removals associated with the CCS project. If a statutory, regulatory or similar requirement (e.g., legal ruling, permit condition) comes into force during the Crediting Period and such requirement effectively mandates the project activity, the GHG Project will no longer be eligible for crediting from the date the statute, regulation or similar requirement takes effect.

Voluntary agreements without an enforcement mechanism, proposed laws or regulations, optional guidelines, or general government policies are not considered in determining whether a project is surplus to regulations. Projects that receive government incentives such as the Inflation Reduction Act (U.S. Congress, 2022), Internal Revenue Service 45Q tax credit (U.S. Department of the Treasury, IRS, 2021) in the U.S. or Canada's investment tax credit or carbon capture utilization and storage (CCUS) (Canada Revenue Agency, 2024) as well as non-tax incentives such as Alberta's Carbon Capture Incentive Program (Government of Alberta, 2023a), Alberta's Industrial Energy Efficiency & CCUS Grant Program (Government of Alberta, 2023b), and Canada's Energy Innovation Program (Natural Resources Canada, 2024) can be eligible for generating ERTs if the emission reductions and/or removals are not a regulatory requirement.

If the quantity of CO_2 captured and stored exceeds the requirements imposed by law, regulation, or other legal mandates, then those additional reductions and/or removals are considered surplus and thereby qualify under the methodology (assuming other requirements are met). For example, if CCS enables a facility to exceed a regulatory performance standard requirement of 1,000 kg CO_2e/megawatt-hour (MWh), then the reductions up to 1,000 kg CO_2e/MWh would not be creditable (since mandated by regulation) but those reductions in excess of the requirement are considered surplus and are creditable.

3.2 Performance Standard

Projects demonstrating additionality via the performance standard are required to achieve a level of performance that, with respect to emission reductions or removals and technologies or practices, is significantly better than average compared with similar, recently undertaken practices or activities in a relevant geographic area. The performance threshold may be:

- **PRACTICE-BASED.** Developed by evaluating the adoption rates or penetration levels of a particular practice within a relevant industry, sector or subsector within the specific region. If these levels are sufficiently low that it is determined the project activity is not common practice, then the project activity is considered additional.
- **TECHNOLOGY STANDARD.** Installation of a particular GHG-reducing technology may be determined to be sufficiently uncommon that simply installing the technology is considered additional.

This Methodology utilizes a technology performance standard to demonstrate that a DAC CO_2 source CCS project carrying out eligible project activities are implementing practices that are sufficiently uncommon in the applicable geographic areas. Deployment of operation of DAC for CCS is discussed in Section 3.2.1.

This Methodology utilizes a practice-based performance standard to demonstrate that a non-DAC CO_2 source CCS project carrying out eligible project activities are implementing practices that exceed the industry standard in the applicable geographic areas. Market adoption rates for these CCS activities are discussed in Section 3.2.1 through Section 3.2.4 .

3.2.1 DAC CCS

There are four operational DAC facilities in the U.S. with a CO_2 capture capacity greater than 100 $MTCO_2$/year (Project Bantam, Oklahoma;[8] Heirloom Tracy, California;[9] Commerce City DAC Plant, Colorado;[10] and The Dalles by 280Earth, Oregon[11]), and one such facility in Canada (Carbon Engineering, British Columbia).[12] The largest of these projects—Project Bantam in Osage County, Oklahoma, with an initial capture rate of 7,000 $MTCO_2$/year—is the only one of these projects that has explicitly announced that it will store the CO_2 in a geologic storage reservoir (Heimdal Inc., 2024).

[8] (Heimdal Inc., 2024)

[9] (Heirloom Carbon Technologies, 2023)

[10] (Global Thermostat, 2023)

[11] (280Earth, n.d.)

[12] https://daccoalition.org/global-dac-deployments/

Heirloom Tracy (1,000 $MTCO_2$/year) announced that it will store the CO_2 in concrete, and the other three facilities have no public plans for CO_2 disposition. The extremely low number of DAC facilities and annual amount of CO_2 captured from all five DAC facilities (less than 10,000 $MTCO_2$/year) demonstrates that the use of DAC in the U.S. and Canada paired with storage in any type of geologic storage reservoir is exceedingly uncommon and is considered additional if the project also passes the regulatory surplus test.

3.2.2 NON-EOR CCS

The number of operational non-EOR CCS projects in the U.S. and Canada remain low. Table 2 and Table 3 compare the number of CO_2 source types eligible under this methodology in the U.S. and Canada, respectively (U.S. EPA, 2024; ECCC, 2024), with the total number of facilities which capture CO_2 that is then injected into a geologic storage reservoir.[13] The overall penetration rate of CO_2 capture with non-EOR CCS is 0.4% (associated with 10 capture facilities) in the U.S. and 0.2% (associated with two capture facilities) in Canada. The low penetration rates of non-DAC CO_2 source geologic storage demonstrate that such practices eligible under this methodology are not common practice in the U.S. and Canada and are considered additional if the project also passes the regulatory surplus test.

Table 2: CO_2 Source Types in the U.S. with CO_2 Capture and Subsequent Injection into a Geologic Storage Reservoir (Excluding CO_2-EOR)

CO_2 SOURCE FACILITY TYPE	NO. OF FACILITIES[14]	NO. OF FACILITIES WITH CO_2 CAPTURE & STORAGE[15]	PENETRATION OF CO_2 CAPTURE & STORAGE	FACILITY PRIMARY NAICS[16] CODES, REPORTING SECTION, OR OTHER REFERENCE
POWER GENERATION (FOSSIL FUELS)	1,212	0	0%	221112

[13] https://co2re.co/FacilityData

[14] Number of facilities is derived from the U.S. EPA GHG reporting program data set for the 2023 reporting year (U.S. EPA, 2024) and only includes facilities that reported GHG emissions in 2023.

[15] Number of facilities is derived from the Global CCS Institute's CO_2RE Global CCS Facilities Database (https://co2re.co/FacilityData), including only operational facilities and excluding facilities for which the CO2 is used for CO2-EOR.

[16] NAICS = North American Industry Classification System

CO_2 SOURCE FACILITY TYPE	NO. OF FACILITIES[14]	NO. OF FACILITIES WITH CO_2 CAPTURE & STORAGE[15]	PENETRATION OF CO_2 CAPTURE & STORAGE	FACILITY PRIMARY NAICS[16] CODES, REPORTING SECTION, OR OTHER REFERENCE
POWER GENERATION (BIOGENIC FUELS[17])	21	0	0%	221112 & 221117
NATURAL GAS PROCESSING	445	5[18]	1%	Subpart W-PROC
PETROLEUM REFINING	130	0	0%	324110
ETHYL ALCOHOL (ETHANOL) MANUFACTURING	165	2	<2%	325193
HYDROGEN MANUFACTURING	114	1	<1%	Subpart Y[19]
NITROGENOUS FERTILIZER MANUFACTURING	32	1	3%	325311
IRON & STEEL MILLS AND FERROALLOY MANUFACTURING	98	1	1%	331110

[17] Includes all power plants (primary NAICS code 221112) that reported biogenic emissions that are >50% of total emissions (i.e., total reported direct emissions + biogenic emissions).

[18] The 30-30 Gas Plant, the Bridgeport Gas Processing Plant (through the Barnett Zero CCS project) and the Campo Viejo Gas Processing Plant (all in Texas); the Dark Horse Treating Facility in New Mexico (Carbon Capture Journal, 2024); and the Red Hills natural gas processing complex in New Mexico (https://co2re.co/FacilityData).

[19] There is overlap between the hydrogen production and petroleum refining facilities because many hydrogen plants are co-located with refineries.

CO_2 SOURCE FACILITY TYPE	NO. OF FACILITIES[14]	NO. OF FACILITIES WITH CO_2 CAPTURE & STORAGE[15]	PENETRATION OF CO_2 CAPTURE & STORAGE	FACILITY PRIMARY NAICS[16] CODES, REPORTING SECTION, OR OTHER REFERENCE
CEMENT MANUFACTURING	87	0	0%	327310
OTHER INDUSTRIAL SOURCES	--	0	0%	--
LANDFILLS[20]	2,639	0	0%	(U.S. EPA, 2025d)
LIVESTOCK AND WASTEWATER TREATMENT ANAEROBIC DIGESTION	>1,600[21]	0	0%	(U.S. EPA, 2025c; U.S. EPA, 2025e)
TOTAL	**>6,543**	**10**	**<0.2%**	

[20] Includes only municipal solid waste landfills.

[21] 400 manure-based anaerobic digestion facilities as of June 2024 (U.S. EPA, 2025e) and anaerobic digesters at over 1,200 Water Resource Recovery Facilities (U.S. EPA, 2025c).

Table 3: CO_2 Source Types in Canada with CO_2 Capture and Subsequent Injection into a Geologic Storage Reservoir (Excluding CO_2-EOR)

CO_2 SOURCE FACILITY TYPE	NO. OF FACILITIES[22]	NO. OF FACILITIES WITH CO_2 CAPTURE & STORAGE[23]	PENETRATION OF CO_2 CAPTURE & STORAGE	FACILITY PRIMARY NAICS[24] CODES OR OTHER REFERENCE
POWER GENERATION (FOSSIL FUELS)	108	1[25]	<1%	221112
POWER GENERATION (BIOGENIC FUELS)	7	0	0%	221119[26]
NATURAL GAS PROCESSING	718	0	0%	(Government of Canada, 2021)
PETROLEUM REFINING	17	0	0%	324110
ETHANOL MANUFACTURING	8	0	0%	325190[27]
HYDROGEN MANUFACTURING	8	1[28]	13%	325120[29]

[22] Number of facilities is derived from ECCC's GHG reporting program data set for the 2023 reporting year (ECCC, 2024).

[23] Number of facilities is derived from Global CCS Institute (https://co2re.co/FacilityData), including only operational facilities and excluding facilities for which the CO_2 is used for CO_2-EOR.

[24] NAICS = North American Industry Classification System

[25] Glacier Gas Plant (natural gas-fired power plant) in Alberta.

[26] Other electric power generation, narrowed down to biomass plants through plant names and internet search.

[27] Other basic organic chemical manufacturing, narrowed down to ethanol facilities through facility names and internet search.

[28] Quest hydrogen plant in Alberta.

[29] Industrial gas manufacturing, narrowed to hydrogen manufacturing facilities through facility names and internet search.

CO_2 SOURCE FACILITY TYPE	NO. OF FACILITIES[22]	NO. OF FACILITIES WITH CO_2 CAPTURE & STORAGE[23]	PENETRATION OF CO_2 CAPTURE & STORAGE	FACILITY PRIMARY NAICS[24] CODES OR OTHER REFERENCE
FERTILIZER (EXCEPT POTASH) MANUFACTURING	9	0	0%	325313
IRON & STEEL MILLS AND FERROALLOY MANUFACTURING	18	0	0%	331110
CEMENT MANUFACTURING	15	0	0%	327310
OTHER INDUSTRIAL SOURCES	--	0	0%	--
LANDFILLS[30]	>3,000	0	0%	(ECCC, 2022)
LIVESTOCK AND WASTEWATER TREATMENT ANAEROBIC DIGESTION	61	0	0%	(CBA & AAFC, 2018)
TOTAL	**>3,969**	**2**	**<0.05%**	

30 Includes only municipal solid waste landfills.

3.2.3 NON-BIOGENIC CO_2 SOURCES FOR EOR-CCS

The use of non-biogenic CO_2 sources of anthropogenic CO_2[31] in EOR is already widespread in certain locations. The performance standard evaluates the prevalence of anthropogenic CO_2 in EOR operations across different regions where the methodology is applicable. Of the locations listed in Table 4, only the Permian Basin passes the practice-based performance standard for the use of non-biogenic sources of anthropogenic CO_2 for CO_2-EOR. Other locations listed in Table 4 are only eligible to demonstrate additionality via the three-pronged additionality test. Those U.S. locations not listed in Table 4 do not have any anthropogenic CO_2 injection taking place and, therefore, such practices eligible under this methodology are not common practice in those locations and are considered additional if the project also passes the regulatory surplus test. The low penetration rates of anthropogenic CO_2 for CO_2-EOR projects in the Permian Basin demonstrate that such practices eligible under this methodology are not common practice and are considered additional if the project also passes the regulatory surplus test.

Table 4. CO_2-EOR Activity Using Anthropogenic CO_2 by Volume

COUNTRY AND REGION	CO_2 INJECTED FOR EOR (MMCF/DAY)	ANTHROPOGENIC CO_2 INJECTED FOR EOR (MMCF/DAY)	ANTHROPOGENIC CO_2 INJECTED FOR EOR (%)
UNITED STATES[32]	**2087**	**744**	**36%**
PERMIAN BASIN (SOUTHEAST NEW MEXICO, WEST TEXAS)	1044	93	9%
SOUTHEAST GULF COAST (EAST TEXAS, LOUISIANA, MISSISSIPPI)	475	130	27%
MID-CONTINENT (NORTH TEXAS, OKLAHOMA, KANSAS)	128	106	83%

[31] For the sake of this performance standard, "anthropogenic CO_2" means CO_2 emissions generated by human activities, particularly from the consumption of fossil fuels and industrial processes.

[32] (ARI, 2025)

ROCKIES (MONTANA, WYOMING, UTAH, AND COLORADO)	420	395	94%
MICHIGAN	20	20	100%
COUNTRY	**CO_2 INJECTED FOR EOR ($MMTCO_2$/YEAR)**	**ANTHROPOGENIC CO_2 INJECTED FOR EOR ($MMTCO_2$/YEAR)**	**ANTHROPOGENIC CO_2 INJECTED FOR EOR (%)**
CANADA[33]	**3.2**	**3.2**	**100%**

3.2.4 BIOGENIC CO_2 SOURCES FOR EOR-CCS

The vast majority of captured CO_2 used for EOR in the U.S. comes from non-biogenic sources. Only two ethanol production facilities provide CO_2 for CO_2-EOR (ARI, 2025), and the amount they can provide is less than 3% of the anthropogenic CO_2 currently utilized for EOR in the U.S. These facilities are capable of supplying up to ~21 MMcf/day[34] out of a total U.S. supply of 744 MMcf/day. All of the CO_2 used for EOR in Canada is from non-biogenic sources.[35] The low penetration rates of biogenic CO_2 for CO_2-EOR projects in both the U.S. and Canada demonstrate that such practices are not common practice and are considered additional if the project passes the regulatory surplus test.

3.3 Three-Pronged Additionality Test

Projects that do not qualify under the performance standard (i.e., non-biogenic sources of CO_2 for EOR-CCS in certain locations) may use the three-pronged additionality test to determine whether project-based GHG emission reductions and removals are above and beyond the "business as usual" scenario and whether carbon market incentives were a significant factor. This methodology requires the Project Proponent to demonstrate that the project activity exceeds existing law, regulation, or other regulatory framework that mandates the project activity, exceeds common practice in the sector and geographic region, and overcomes a financial implementation barrier. Section 3.1 shall be

[33] (ECCC, 2025)

[34] Calculated from a maximum potential of 250,000 $MTCO_2$/year from the CapturePoint Arkalon plant and a supply of ~150,000 $MTCO_2$/year from the Bonanza BioEnergy plant (Bryan, 2024), both of which are located in Kansas.

[35] Sources of CO_2 for EOR in Canada include the Dakota Gasification Synfuels Plant (produces syngas from coal), SaskPower's Boundary Dam unit (coal electricity generation unit), a Nutrien fertilizer plant, and the Sturgeon Refinery (https://co2re.co/FacilityData). All of these facilities use fossil fuels.

used to demonstrate regulatory surplus. Alternative geographic delineations than those presented in Table 4 may be used to establish the geographic region when assessing common practice. The financial implementation barrier must be supported by evidence and not overestimated. Refer to the *ACR Standard* for a complete description of the ACR three-pronged additionality test.

4 Project Boundaries

Consistent with the *ACR Standard*, the project boundaries include a physical boundary, a GHG assessment boundary, and a temporal boundary. The project boundaries are intentionally drawn broadly to include emissions from CO_2 capture, transport, injection and storage, and monitoring, as well as CO_2 recovery and re-injection operations at CO_2-EOR sites, if applicable. For CO_2-EOR projects, that boundary also includes emissions from the production, transport, refining and processing, and end use of oil and associated gas produced through CO_2-EOR.

4.1 Physical Boundary

The physical boundary demarcates the implementation area as it relates to GHG emission sources, sinks, and reservoirs included in the baseline and with-project scenario emission calculations and may extend beyond property boundaries and project rights of way.

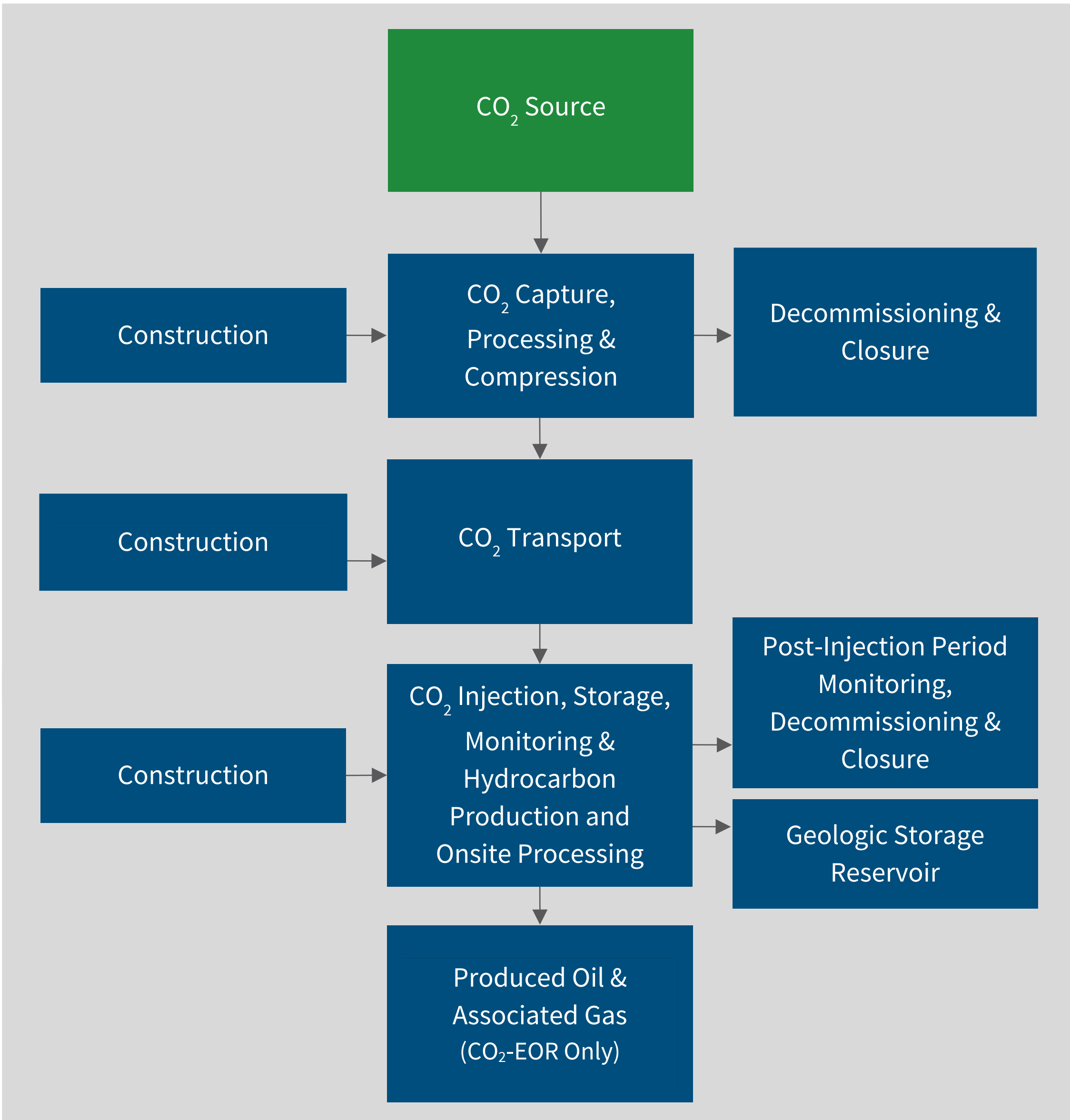
To ensure that the emission reductions calculation approach reflects the relevant change in emissions due to the project, the physical boundary shall incorporate all GHG sources affected by the project in the baseline and with-project scenarios (i.e., the change in overall emissions due to capturing, transporting, and storing CO_2). The installation of CO_2 capture equipment or processes may impact different sources of emissions at a facility and may require the inclusion of one or more emission sources from the CO_2 source creating the captured CO_2. Projects may include multiple capture sites, modes of transportation, injection sites, and storage reservoirs. Project configurations may vary from a single site with capture and co-located injection and storage to more complex hub-and-spoke[36] projects with a variety of segment configurations. The boundary does not include upstream carbon accounting from biomass fuels.

The physical boundary for CCS projects is depicted in Figure 3.

I. All SSRs inside the grey box are included and must be accounted for under this methodology.
II. SSRs in green boxes are relevant to the baseline and project emissions.
III. SSRs in blue boxes are relevant only to project emissions.

[36] Infrastructure design where multiple CO_2-emitting sources (the "spokes") are connected to a central facility (the "hub") that handles the transportation and storage of the captured carbon dioxide.

Figure 3: Project Boundary Diagram for CCS Projects



The physical boundary may be adjusted over time by the addition or removal of CO_2 sources and transport modes, and the addition of geologic storage reservoirs.

For each registered GHG Project, a Project Proponent may only include project activities that result in GHG emission reductions being generated within the geographic boundary of one country.[37] CCS projects are considered to reduce or remove emissions in the country in which the capture of the CO_2 emissions occurred.

4.2 GHG Assessment Boundary

GHG sources, sinks, and reservoirs relevant to this Methodology are listed in Table 5 below. Project Proponents shall consider the emission sources provided below when assessing baseline and project emissions.

Table 5: GHG Sources, Sinks and Reservoirs

SSR	GHG SOURCES, SINKS AND RESERVOIRS	GHGs	INCLUDED (I) OR EXCLUDED (E)	JUSTIFICATION
CO_2 SOURCE	Combustion emissions[38]	CO_2, CH_4, N_2O	I	This source is the primary contributor to the CO_2 stream captured for geologic storage.
	Offsite electricity and thermal energy used by CO_2 source	CO_2, CH_4, N_2O	I	Emissions associated with this source may represent a substantial portion of the project's total emissions.

[37] This ensures accurate representation of the host countries associated with projects and credits for the purpose of facilitating use under the Paris Agreement.

[38] Everywhere that stationary combustion is referred to in Table 5 and in Methodology equations, it should be interpreted as "stationary combustion or other energy production process (e.g., redox reaction in a fuel, pyrolysis, gasification)" and most references to "fuel" can be read as "fuel or other energy-producing input." Emission factors for non-combustion energy production shall be derived from the same sources as those listed for stationary combustion (e.g. U.S. EPA for U.S. projects, ECCC for Canadian CCS projects).

SSR	GHG SOURCES, SINKS AND RESERVOIRS	GHGs	INCLUDED (I) OR EXCLUDED (E)	JUSTIFICATION
CO_2 CAPTURE, PROCESSING, & COMPRESSION	Combustion emissions associated with CO_2 capture, processing, and compression processes	CO_2, CH_4, N_2O	I	This source is the primary contributor to the CO_2 stream captured for geologic storage.
	Offsite electricity and thermal energy used by CO_2 capture, processing, and compression processes	CO_2, CH_4, N_2O	I	Emissions associated with this source may represent a substantial portion of the project's total emissions.
	Vented and fugitive emissions from equipment associated with CO_2 capture, processing, and compression processes	CO_2, CH_4	I	Emissions associated with this source may represent a not insignificant portion of the project's total emissions.
	CO_2 transferred to another entity and not injected for permanent storage[39]	CO_2	I	Accounts for CO_2 captured but not stored (e.g., CO_2 sold for other uses)
CO_2 TRANSPORT	Combustion emissions associated with transport of CO_2 from CO_2 source to the injection and storage site	CO_2, CH_4, N_2O	I	Emissions associated with this source may represent a substantial portion

[39] CO_2 can be transferred at any stage of a CO_2 project, not just during the capture process phase. Transferred CO_2 is counted in the project emission in the segment (e.g., capture, transport, storage) that the transfer occurred, but are not included in every segment above for simplicity.

SSR	GHG SOURCES, SINKS AND RESERVOIRS	GHGs	INCLUDED (I) OR EXCLUDED (E)	JUSTIFICATION
				of the project's total emissions.
	Offsite electricity used by all modes of transportation	CO_2, CH_4, N_2O	I	Emissions associated with this source may represent a substantial portion of the project's total emissions.
	Vented and fugitive emissions	CO_2	I	Emissions associated with this source may represent a not insignificant portion of the project's total emissions.
CO_2 INJECTION, STORAGE, MONITORING & HYDROCARBON PRODUCTION AND ONSITE PROCESSING	Combustion emissions from operation of equipment associated with injection, storage, monitoring & hydrocarbon production and onsite processing	CO_2, CH_4, N_2O	I	Emissions associated with this source may represent a substantial portion of the project's total emissions.
	Offsite electricity and thermal energy used by injection, storage, monitoring & hydrocarbon production and onsite processing	CO_2, CH_4, N_2O	I	Emissions associated with this source may represent a substantial portion of the project's total emissions.

SSR	GHG SOURCES, SINKS AND RESERVOIRS	GHGs	INCLUDED (I) OR EXCLUDED (E)	JUSTIFICATION
	Vented and fugitive emissions from equipment associated with injection, storage, monitoring & hydrocarbon production and onsite processing	CO_2, CH_4	I	Emissions associated with this source may represent a not insignificant portion of the project's total emissions.
CONSTRUCTION	Combustion emissions associated with construction	CO_2, CH_4, N_2O	I	Emissions associated with this source may represent a moderate portion of the project's total emissions.
	Offsite electricity and thermal energy used for construction	CO_2, CH_4, N_2O	I	Emissions associated with this source may represent a not insignificant portion of the project's total emissions.
	Cement, asphalt, and steel production[40] emissions	CO_2, CH_4, N_2O	I	Emissions associated with this source may represent a moderate portion of the project's total emissions.

[40] This excludes the emissions associated with the production of large mobile equipment (e.g., cranes, forklifts, trucks, loaders).

SSR	GHG SOURCES, SINKS AND RESERVOIRS	GHGs	INCLUDED (I) OR EXCLUDED (E)	JUSTIFICATION
	Production of materials that enable CO_2 capture	CO_2, CH_4, N_2O	E	Emissions associated with this source are de minimis.
	Pipeline and pipeline compressor production emissions[41]	CO_2, CH_4, N_2O	I	Emissions associated with this source may represent a moderate portion of the project's total emissions.
POST-INJECTION PERIOD MONITORING, DECOMMISSIONING & CLOSURE	Combustion emissions associated with post-injection period monitoring, decommissioning and closure	CO_2, CH_4, N_2O	I	Emissions associated with this source may represent a moderate portion of the project's total emissions.
	Offsite electricity and thermal energy used during post-injection period monitoring, decommissioning and closure	CO_2, CH_4, N_2O	I	Emissions associated with this source may represent a not insignificant portion of the project's total emissions.
	Cement emissions	CO_2, CH_4, N_2O	I	Emissions associated with this source may represent a moderate portion

[41] Emissions associated with the manufacturing of pipelines and pipeline compressors are limited to those pipelines and compressors that were installed for the purpose of use in the CCS project (whether meant to be used in whole or in part by the CCS project).

SSR	GHG SOURCES, SINKS AND RESERVOIRS	GHGs	INCLUDED (I) OR EXCLUDED (E)	JUSTIFICATION
				of the project's total emissions.
PRODUCED OIL & ASSOCIATED GAS (CO_2-EOR ONLY)	Crude oil and associated gas off-site production, refining and processing emissions	CO_2, CH_4, N_2O	I	Emissions associated with this source represent a substantial portion of the project's total emissions.
	Transport emissions (from CO_2 injection and storage site through to end use)	CO_2, CH_4	I	Emissions associated with this source may represent a moderate portion of the project's total emissions.
	Combustion of oil and gas end-product	CO_2, CH_4, N_2O	I	Emissions associated with this source represent a substantial portion of the project's total emissions.
GEOLOGIC STORAGE RESERVOIR	Emissions from the geologic storage reservoir	CO_2	I	If it were to occur, release of stored CO_2 would become an emission that could be substantial based on the amount released.

4.3 Temporal Boundary

Start Date, Crediting Period, Reporting Period, and Minimum Project Term are defined in the *ACR Standard* as are relevant deadlines associated with project listing, validation, and verification. The following sections provide additional details relevant to this Methodology.

4.3.1 START DATE

The project Start Date may be denoted by one of the following:

- The date when eligible CO_2 is first injected as part of a reservoir or pilot test;
- The date when eligible CO_2 is being injected at designed storage capacity; or

4.3.2 CREDITING PERIOD

The Crediting Period for project activities that only include DAC as the CO_2 source will be fifteen (15) years. The Crediting Period for project activities that include non-DAC CO_2 sources will be twelve (12) years. The Crediting Period for project activities involving CO_2-EOR shall be one non-renewable Crediting Period of twelve (12) years. Where different Crediting Periods may apply, the shortest Crediting Period shall apply.[42]

Regardless of the project Start Date, the Crediting Period begins when CO_2 storage begins, excluding CO_2 injection as part of a reservoir or pilot test.

If eligible for renewal, a Project Proponent may apply to renew the Crediting Period following the process described in the then-current *ACR Standard*.

4.3.3 REPORTING PERIOD

The duration of any given Reporting Period is at the discretion of the Project Proponent, provided it conforms to the requirements of the *ACR Standard* and the MRV requirements herein.

[42] e.g., project with one industrial CO_2 source and one DAC CO_2 source with storage in a saline reservoir shall have a Crediting Period of twelve (12) years.

4.3.4 MINIMUM PROJECT TERM

For CCS projects the Minimum Project Term begins on the Start Date and includes the period of CO_2 injection during the Crediting Period and ends a minimum of five (5) years after the end of the Crediting Period and only once plume stabilization and CO_2 containment is assured. After the cessation of CO_2 injection, the GHG Project enters the post-injection monitoring period, the results of which must demonstrate whether stabilization of the CO_2 plume can be assured (discussed in Section 7.3.12). If it cannot be demonstrated that the plume has stabilized and CO_2 is contained, the Minimum Project Term will be extended in two-year increments until these requirements are met.

4.4 Net Zero Transition

U.S. and Canadian federal governments have identified CCS as a critical component in achieving emission reduction goals. The U.S. executive identified CCS as essential for reducing difficult-to-abate emissions and addressing any overshoot of mid-century climate targets and projected that the U.S. may need to deploy up to 1 $GTCO_2$ CCS per year by 2050 (U.S. Executive Office of the President, 2021). Canada's 2030 Emission Reduction Plan required under the Net-Zero Emissions Accountability Act outlines a policy commitment to capture and store at least 15 $MMTCO_2$ annually by 2030 through CCUS deployment (Government of Canada, 2022).

The emissions associated with the production, transport, refining and processing, and end use of oil and associated gas produced by CO_2-EOR processes are included in project emissions. Oil produced via CO_2-EOR processes eligible under this methodology has a lower carbon footprint relative to other oil production due to the simultaneous injection and storage of non-geologic CO_2 that would otherwise be emitted to the atmosphere. However, since CO_2-EOR enables the production of fossil fuels that will contribute to emissions, and because the projects must demonstrate a net benefit to the atmosphere, the methodology requires that the downstream emissions from the production and use of the oil and associated gas extracted via CO_2-EOR are included in the project accounting boundary. Projects must demonstrate a net benefit to the atmosphere (IEA, 2021).

5 Baseline Determination

5.1 Baseline Description

Baseline includes emissions from CO_2 sources listed in Table 1. The methodology presents two approaches for calculating the baseline, referred to as project-based and intensity-based.

A Project Proponent uses the baseline approach that applies to its project and then follows the matching calculation procedure. Projects in which a primary CO_2 source is subject to an emission intensity metric or limit must calculate both types of baselines and the Project Proponent must demonstrate that the more conservative (lower) baseline has been applied.

For projects where CO_2 is removed from the atmosphere through direct air capture, a project-based baseline shall be used. This baseline represents the project's actual CO_2 capture prior to transport and permanent storage. The baseline shall be determined by measured quantities of CO_2 captured by the project, which would have remained in the atmosphere had the CCS project not been implemented. For BECCS and BiCRS projects, in which CO_2 is also removed from the atmosphere, the project-based baseline shall be used unless the CO_2 source is subject to an emissions intensity limit or other CO_2 emissions limit that includes biogenic emissions in the limit.

The Methodology conservatively assumes that no oil production occurs in the baseline scenario. This approach is appropriate because it aligns with Article 6.4 of the Paris Agreement requirements for baseline below business as usual and counters assertions that the Methodology encourages the production of additional oil.

5.1.1 PROJECT-BASED BASELINE APPROACH

The project-based baseline approach calculates the baseline as the CO_2 source's CO_2 emissions had the CO_2 source operated without capture and storage (the project activity). For example, if the CCS project includes a coal electricity generator with post-combustion capture, the baseline would be the measured CO_2 emissions from the coal plant producing the same quantity of electricity without CO_2 capture. Similarly, if the CCS project captures CO_2 from acid-gas removal associated with natural gas production, the baseline would be the natural gas production facility operating at the same volumes of acid gas removal but with CO_2 vented to the atmosphere. This baseline approach will apply to most CCS projects. An equation is provided in Section 6.1.2.

5.1.2 INTENSITY-BASED BASELINE APPROACH

The intensity-based baseline approach calculates the baseline taking into account established emissions limits, if applicable. This approach shall only be used when the CO_2 source is subject to a regulatory or other legally required emissions intensity metric[43] (e.g., $MTCO_2e$ per unit of output) or other limit on CO_2 source GHG emissions. For instance, if the CO_2 source is an electricity generating facility that is subject to a limit of 1,000 lb. CO_2/MWh, the baseline shall be calculated by multiplying the actual amount of electricity delivered to the grid in the project condition (net MWh) times the regulatory emissions rate (1,000 lb. CO_2/MWh). Because emissions intensity metrics and other CO_2 emissions limits can vary over time, by CO_2 source type, and other conditions, these metrics must be re-assessed for applicability and re-quantification in each Reporting Period. An equation is provided in Section 6.1.3.

[43] Sometimes called a “rate-based performance standard”

6 Quantification of GHG Emission Reductions and Removals

This section details the methods and equations to quantify baseline emissions, project emissions, and emission reductions and/or removals. There are two pathways for a GHG Project to generate removal credits: capturing CO_2 from technology-based DAC and capturing CO_2 through BECCS/BiCRS using sustainable biomass as described in Appendix D. All other project types generate emission reductions. Most CCS projects will exclusively generate one type of credit but, if a project involves a variety of sources that results in a mix of emission reductions and removals, the Project Proponent may elect to distinguish between emission reductions and removals for a given Reporting Period. If electing to distinguish between these emission types, the Project Proponent must track and report baseline emissions by CO_2 source. Total GHG Emission Reductions and Removals and Net GHG Emission Reductions and Removals will be proportionally allocated based on the relative share of each removal-eligible CO_2 source and each reduction-eligible CO_2 source.

Project Proponents shall determine which equations apply to their project based on an evaluation of project and baseline configurations and on project-specific conditions. For instance, if a project's CO_2 source is located on top of the geologic storage reservoir and no CO_2 transport is required, the Project Proponent shall exclude CO_2 transport-related data and equations.

The equations and accounting/measurement of CO_2 are based on project boundaries included in this methodology and support simple projects as well as hub-and-spoke projects. Alternative quantification methods are included in Appendix C.

6.1 Baseline GHG Emissions

Two approaches can be used to calculate baseline CO_2 emissions from the CO_2 source: project-based and intensity-based. The more conservative baseline must be chosen. To ensure that baseline emissions from electrical power generation and industrial CO_2 sources are below the business-as-usual level of emissions, the baseline emissions equations do not include methane (CH_4) or nitrous oxide (N_2O) emissions from these sources and must use the most conservative calculation of captured CO_2, which must be measured continuously. To ensure that baseline emissions from direct air capture deliver equivalent outcomes that avoid over-estimating mitigation from an activity, CO_2 captured from the atmosphere must be measured continuously.

6.1.1 FUNCTIONAL EQUIVALENCE

The principle of functional equivalence dictates that the baseline emissions calculated and the project emissions measured shall provide the same function while delivering comparable products in quality and quantity. In the case of CCS projects, the implementation of CO_2 capture infrastructure may result in changes to energy consumption and/or product output which could impact the quantity of GHG emissions produced at the capture site. In some project configurations, incremental emissions associated with operating the capture system could yield an overall increase in CO_2 production and result in a larger volume of CO_2 captured and processed, relative to what the primary process would have emitted in the baseline. A power plant retrofitted with post-combustion CO_2 capture, for instance, that maintains (net) electricity production levels by burning additional coal to produce steam and electricity to power the capture system would increase overall CO_2 production. In this case, using actual measured CO_2 production values from the project to derive baseline emissions would overestimate baseline emissions. This increase in energy needed to operate the power plant with capture equipment is known as "parasitic load." The key consideration in applying the principle of functional equivalence to the baseline is ensuring that the baseline reflects what CO_2 would have been produced in the absence of capturing CO_2 from the CO_2 source (e.g., power plant).

In other project configurations, some or all of the incremental energy needed to meet the demands of the CO_2 capture system could be provided through separately powered systems (called "secondary CO_2 sources"[44] when at least some of the produced CO_2 is captured and can be separately quantified from CO_2 produced from primary CO_2 source(s)). Examples of potential secondary CO_2 sources are process heaters, boilers, engines, turbines, and other fuel-fired equipment. The CO_2produced by this equipment is *not* included in the baseline if the CO_2 source's produced CO_2 is physically able to be separately quantified (i.e., separately metered) from the primary CO_2 source's produced CO_2. (Note that all GHGs produced by CCS project equipment, excluding primary CO_2 sources, must be quantified as project emissions; CO_2 from secondary CO_2 sources that is captured and injected underground is subtracted from project emissions.)

Project Proponents shall adjust actual project data relied upon to quantify baseline emissions. This is done to ensure a conservative baseline and that the quantified emission reductions appropriately represent the atmospheric benefit of the CCS project and that the comparison between project and baseline emissions maintains functional equivalence. Further, during periods of non-compliance with air permits, the effect on CO_2 emissions shall be evaluated and any increases in CO_2 over normal operations for that period will be deducted from baseline emissions.

[44] "Secondary CO_2 sources" and "primary CO_2 sources" (both discussed in Section 6.1.2 and defined in the Definitions section) are mutually exclusive.

6.1.2 CO_2 SOURCE EMISSIONS WITH PROJECT-BASED BASELINE APPROACH

The project-based baseline requires the mass of captured CO_2 from the project with an adjustment factor to represent the quantity of CO_2 emissions that would have occurred in the absence of the CCS project assuming a consistent level of production or activity. This involves metering the quantity of CO_2 captured immediately downstream of primary CO_2 sources. Primary CO_2 sources are CO_2 sources that would have existed in the absence of the CCS project. The amount of CO_2 produced and captured from the primary CO_2 source(s) shall be compared to the amount of CO_2 from primary CO_2 source(s) injected underground,[45] both measured during each Reporting Period, and the lesser of those values as determined in Equation 2 used in Equation 1.

An adjustment factor is a part of the equation to maintain functional equivalence between the baseline and project emissions for project-based baselines. The adjustment factor accounts for decreased efficiency or output (if any) of the primary CO_2 source caused by the project. Project Proponents shall determine the appropriate way to correct measured CO_2 emissions on a project-by-project basis for each CO_2 source and justify to the validation/verification body (VVB) how the adjustment factors applied have maintained functional equivalence between the baseline and project scenarios. The Project Proponent must demonstrate that the project-based baseline is the more conservative baseline.

Equation 1: CO_2 Source Emissions with Project-Based Baseline Approach

$$BE_{Project-Based_t} = \sum_{c,t} \left(\text{Baseline Captured } CO_{2_{c,t}} \times AF_c \right)$$

WHERE

$BE_{Project-Based_t}$	Baseline emissions for a CCS project where the baseline scenario is defined using a project-based approach in Reporting Period **t** ($MTCO_2e$).
$\text{Baseline Captured } CO_{2_{c,t}}$	Mass of CO_2 used in baseline Equation 1 for primary CO_2 source **c** in Reporting Period **t** ($MTCO_2$). Refer to Equation 2.

[45] Note that this must exclude CO_2 sourced from natural CO_2-bearing formations because it is ineligible (refer to Section 2).

AF_c	The fraction of measured CO_2 from primary CO_2 source **c** that would have been present without CCS project at the same useful output (unitless).[46] $\mathbf{AF_c}$ must be greater than 0 and less than or equal to 1. Note that $\mathbf{AF_c}$ is calculated once and validated during the first Reporting Period. It is not re-calculated for each Reporting Period unless there have been fundamental changes to the function of the CO_2 source. Examples: • If a primary CO_2 source is separately run and operated from all capture-related equipment and there is no change to the primary CO_2 source's CO_2 emissions (including any captured CO_2) from the project, insert 1 (one) for this term. • If 20% of the GHG emissions (and captured CO_2) from the primary CO_2 source are caused by the use of CO_2 capture equipment (or any other project-related equipment or operations) to the primary CO_2 source, an adjustment factor of 0.80 shall be used. **NOTE:** $\mathbf{AF_c}$ adjusts the baseline to reflect the emissions that would have existed with the CCS project. Any additional emissions emitted or captured because of the CCS project (i.e., GHGs emitted from capture equipment, CO_2 produced and captured from secondary CO_2 sources) are not part of the baseline and are accounted for as project emissions as discussed in Section 6.2.1.

The following equation shall be used to determine which measured value is more conservative—the amount of CO_2 produced and captured by primary CO_2 source(s) during the Reporting Period *or* the amount of CO_2 from primary CO_2 source(s) injected underground during the Reporting Period, excluding the excess CO_2 (from both primary and secondary sources) produced during periods of air permit non-compliance. Note that both values must be calculated.

[46] This variable is included to maintain functional equivalence between the baseline and project.

Equation 2: Mass of CO_2 Used in Baseline Equation 1

$$\text{Baseline Captured } CO_{2_{c,t}} = \textit{lesser of} \sum_{c} \text{Captured Primary } CO_{2_{c,t}}$$

$$\textit{or}$$

$$\sum_{g} CO_2 \text{ Injected}_{g,t} - \sum_{x} \text{Captured Secondary } CO_{2_{x,t}} - \sum_{c} \left(\text{Vol.}_{\text{Primary Excess Gas}_{c,t}} \times \%CO_{2_{c,t}}\right) \times \rho CO_2$$

WHERE

$\text{Baseline Captured } CO_{2_{c,t}}$	Calculated mass of CO_2 from primary CO_2 sources **c** used in Equation 1 in Reporting Period **t** ($MTCO_2$).
$\text{Captured Primary } CO_{2_{c,t}}$	CO_2 that is both produced and captured from all primary CO_2 sources **c** in Reporting Period **t** during periods of air permit(s) compliance, as well as during periods of air permit non-compliance during which no excess CO_2 was produced ($MTCO_2$). Refer to Equation 3.
$CO_2 \text{ Injected}_{g,t}$	CO_2 injected into wells in all geologic storage reservoirs **g**, measured at the surface point(s) of injection, in Reporting Period **t** ($MTCO_2$). Refer to Equation 25.
$\text{Captured Secondary } CO_{2_{x,t}}$	CO_2 produced and captured from all secondary CO_2 sources **x** in Reporting Period **t** during periods of air permit(s) compliance, as well as during periods of air permit non-compliance during which no excess CO_2 was produced ($MTCO_2$). Refer to Equation 4.
$\text{Vol.}_{\text{Primary Excess Gas}_{c,t}}$	Volume of excess CO_2 gas produced from CO_2 source **c** due to air permit violations (if any) in Reporting Period **t**; this volume shall be measured continuously at (or corrected to) standard conditions[47] at a point immediately downstream of the primary CO_2 source (m^3). This value is a subset of $\text{Vol.}_{\text{Primary Gas Captured}_{c,t}}$

[47] Standard conditions are a temperature of 60 degrees Fahrenheit and an absolute pressure of 1 atmosphere.

	(see Equation 3). See the Definitions section for a definition of "excess CO_2."
$\%CO_{2_{c,t}}$	Concentration of CO_2 in the gas stream from primary CO_2 source **c** in Reporting Period **t**, measured at a point immediately downstream of the primary CO_2 source and in relation to $Vol._{Primary\ Excess\ Gas_{c,t}}$ in a location that allows for accurate measurement, in Reporting Period **t** (%CO_2 by volume, expressed as a decimal).
ρCO_2	Density of CO_2 at standard conditions = 0.001858 metric tons/m^3.

The following equation shall be used to calculate CO_2 emissions captured from primary CO_2 sources. An example of a primary CO_2 source is an electricity generation facility that was retrofitted with CO_2 capture equipment. Baseline emissions shall only be calculated from periods during which the primary CO_2 source(s) was (were) in compliance with air permitting requirements and periods during which the primary CO_2 source(s) was (were) out of compliance with air permitting requirements but during which no excess CO_2 was produced. Excess CO_2 is defined as "an increase in CO_2 produced as a result of non-compliance with air permits."

Equation 3: CO_2 Emissions Captured from Primary CO_2 Sources During Periods of Air Permit Compliance[48]

$$\mathbf{Captured\ Primary\ CO_{2_{c,t}}} = \sum_{c}\left(\left(\mathbf{Vol._{Primary\ Gas\ Captured_{c,t}}} - \mathbf{Vol._{Primary\ Excess\ Gas_{c,t}}}\right) \times \%\mathbf{CO_{2_{c,t}}}\right) \times \boldsymbol{\rho}\mathbf{CO_2}$$

WHERE

$Captured\ Primary\ CO_{2_{c,t}}$	Total CO_2 produced and captured from primary CO_2 source **c** in Reporting Period **t** during periods of air permit(s) compliance and during periods of air permit non-compliance during which no excess CO_2 was produced ($MTCO_2$). This value is utilized in Equation 2. Primary CO_2 sources are those that would only have existed without a CCS project (e.g., an electricity generator) and excludes

[48] As well as during periods of air permit non-compliance during which no excess CO_2 was produced.

	sources that exist only because of the project (e.g., capture equipment).
$Vol._{Primary\ Gas\ Captured_{c,t}}$	Total volume of gas (containing CO_2 and other compounds) produced and captured from primary CO_2 source **c** in Reporting Period **t**; this volume shall be measured continuously at (or corrected to) standard conditions and measured at a point immediately downstream of the point of CO_2 capture (m^3 gas). For eligible DAC, BECCS, and BiCRS projects, this amount shall be equal to the amount of CO_2 removed from the atmosphere.
$Vol._{Primary\ Excess\ Gas_{c,t}}$	Volume of excess CO_2 gas produced from CO_2 source **c** due to air permit violations (if any) in Reporting Period **t**; this volume shall be measured continuously at (or corrected to) standard conditions at a point immediately downstream of the primary CO_2 source (m^3). This value is a subset of $Vol._{Primary\ Gas\ Captured_{c,t}}$ (see Equation 3). See the Definitions section for a definition of "excess CO_2."
$\%CO_{2_{c,t}}$	Concentration of CO_2 in the gas stream from primary CO_2 source **c**, measured at a point immediately downstream of the point of CO_2 capture and in relation to $Vol._{Primary\ Gas\ Captured_{c,t}}$ and $\mathbf{Vol._{Primary\ Excess\ Gas_{c,t}}}$ in a location that allows for accurate measurement,[49] in Reporting Period **t** (%CO_2 by volume, expressed as a decimal).
ρCO_2	Density of CO_2 at standard conditions = 0.001858 metric tons/m^3.

The following equation shall be used to calculate CO_2 emissions captured from secondary CO_2 sources. Any excess CO_2 that was produced due to air permit violations shall also be excluded from this calculation.

[49] e.g., where gas stream flow is laminar, meaning flow is not cyclonic or turbulent; no new flow is introduced like cooling air.

Equation 4: CO_2 Emissions Captured from Secondary CO_2 Sources During Periods of Air Permit Compliance[50]

$$\text{Captured Secondary } CO_{2_{x,t}} = \sum_{x} \left(\left(Vol._{\text{Secondary Gas Captured}_{x,t}} - Vol._{\text{Secondary Excess Gas}_{x,t}} \right) \times \%CO_{2_{x,t}} \right) \times \rho CO_2$$

WHERE

$\text{Captured Secondary } CO_{2_{x,t}}$	Total CO_2 produced and captured from secondary CO_2 source **x** in Reporting Period **t** during periods of air permit(s) compliance, as well as during periods of air permit non-compliance during which no excess CO_2 was produced ($MTCO_2$). CO_2 source **x** represents a CO_2 source that exists because of the CCS project (i.e., sources that exist to facilitate activities associated with the project). This excludes CO_2 accounted for in $PE_{\text{S-Entrained}_{CO_{2_t}}}$ (refer to Equation 24).
$Vol._{\text{Secondary Gas Captured}_{x,t}}$	Total volume of gas (containing CO_2 and other compounds) produced and captured from secondary CO_2 source **x** in Reporting Period **t**; this volume shall be measured continuously at (or corrected to) standard conditions at a point immediately downstream of the point of CO_2 capture (m^3).
$Vol._{\text{Secondary Excess Gas}_{x,t}}$	Volume of excess CO_2 gas produced from secondary CO_2 source **x** due to air permit violations (if any) in Reporting Period **t**; this volume shall be measured continuously at (or corrected to) standard conditions at a point immediately downstream of the point of CO_2 capture (m^3). This value is a subset of $Vol._{\text{Secondary Gas Captured}_{x,t}}$.
$\%CO_{2_{x,t}}$	Concentration of CO_2 in the gas stream from CO_2 source **x**, measured at (or corrected to) standard conditions at a point immediately downstream of the point of CO_2 capture and in relation to $Vol._{\text{Secondary Gas Captured}_{x,t}}$ and $Vol._{\text{Secondary Excess Gas}_{x,t}}$ in a location that allows for accurate measurement, in Reporting Period **t** (%CO_2 by volume, expressed as a decimal).

[50] As well as during periods of air permit non-compliance during which no excess CO_2 was produced.

ρCO_2	Density of CO_2 at standard conditions = 0.001858 metric tons/m^3.

6.1.3 CO_2 SOURCE EMISSIONS WITH INTENSITY-BASED BASELINE APPROACH

The intensity-based baseline is calculated by multiplying an emissions intensity metric, expressed as $MTCO_2e$/unit of output, by the actual output of the project's CO_2 source (e.g., MWh for power generation, MMscf of gas processed, tons of product produced). The emissions intensity metric shall be derived from a legally enforceable standard such as a facility-specific permit limit or regulation.

Project Proponents must ensure that the unit of measurement used in the intensity-based baseline matches the unit used for quantifying project emissions. This consistency is critical for the application of Equation 5 and for maintaining methodological integrity across Reporting Periods. Measurement procedures used to determine the quantity of output must be consistent with the physical project boundary and unit definitions embedded in the selected emissions intensity metric. Further, the output value used to calculate baseline emissions shall be set to ensure that the quantified emission reductions appropriately represent the impact of the CCS project. For example, in CCS projects that involve power generation, electricity may be used to operate the CO_2 compressors or other equipment associated with the capture system, reducing the amount of electricity delivered to the grid or sold to direct-connected users, as compared to a facility without CO_2 capture. In this case, the Project Proponent shall use gross electricity production as the output instead of net electricity production.

If a more stringent or updated emission intensity metric or performance standard comes into effect mid-Reporting Period, the Project Proponent must either use the more conservative of the standards for the entire Reporting Period or apply each metric to the parts of the Reporting Period in which the metric is applicable. Also, as noted in Section 5.1, projects in which a primary CO_2 source is subject to an emission intensity metric or limit must calculate both a project-based baseline and intensity-based baseline and use the most conservative (lowest) baseline.

Equation 5: CO_2 Source Emissions with Intensity-Based Baseline Approach

$$BE_{Intensity-Based_t} = \sum_{c} BE_{Intensity\ Metric_{c,t}} \times Output_{c,t}$$

WHERE

$BE_{Intensity-Based_t}$	Intensity-based baseline emissions for all CO_2 sources **c** in Reporting Period **t** ($MTCO_2e$).
$BE_{Intensity\ Metric_{c,t}}$	Baseline emissions intensity metric, specific to the type of CO_2 source **c** that creates the CO_2 for capture, as prescribed by regulatory or other legally required (e.g., permit) emissions intensity metric, in Reporting Period **t** ($MTCO_2e$/unit of output).
$Output_{c,t}$	Total production unit of output (e.g., MWh, MMscf) of CO_2 source **c** in the project condition in Reporting Period **t** (unit of output).

6.2 Project GHG Emissions

CCS project emissions equal the sum of CO_2e emissions from the CO_2 capture, processing, and compression equipment; CO_2 transport; permanent storage; construction and closure, and for (CO_2-EOR only) oil production, as shown in the following equation. When CO_2 from natural CO_2-bearing formations is used in the project (e.g., for CO_2-EOR), any emissions of this CO_2 must be included in project emissions.

Equation 6: Total Project Emissions

$$
\begin{aligned}
\mathbf{PE_t} = \mathbf{PE_{Capture_t}} + \mathbf{PE_{Transport_t}} + \mathbf{PE_{Storage_t}} \\
- \left(\mathbf{Captured\ Secondary\ CO2_t} - \mathbf{PE_{Offsite\ CO_2\ Transfer_t}}\right) \\
+ \left(\mathbf{PE_{Construct-Pre_t}} + \mathbf{PE_{Post-Inj_t}}\right) \times \frac{\mathbf{RP_t}}{\mathbf{Days \times\ AP}} \\
+ \mathbf{PE_{Construct-RP_t}} + \mathbf{PE_{Post-Inj-Addl_t}} + \mathbf{CO2_{Atm\ Emissions-Inj_t}} + \mathbf{PE_{Hydrocarbon_t}}
\end{aligned}
$$

WHERE

PE_t	Project emissions from CCS project in Reporting Period **t** ($MTCO_2e$).
$PE_{Capture_t}$	GHG emissions from CO_2 capture, processing, and compression in Reporting Period **t** ($MTCO_2e$). Refer to Section 6.2.1.
$PE_{Transport_t}$	GHG emissions from CO_2 transport in Reporting Period **t** ($MTCO_2e$). Refer to Section 6.2.2.
$PE_{Storage_t}$	GHG emissions from CO_2 injection, storage, monitoring, and hydrocarbon production and onsite processing in Reporting Period **t** ($MTCO_2e$). Refer to Section 6.2.3.
$\text{Captured Secondary } CO2_t$	CO_2 produced and captured from secondary CO_2 sources in Reporting Period **t** ($MTCO_2$). Refer to Equation 4.
$PE_{Offsite\ CO_2\ Transfer_t}$	All captured CO_2 transferred outside the project boundary (i.e., not injected underground) in Reporting Period **t** ($MTCO_2$). Refer to Equation 7.
$PE_{Construct-Pre_t}$	GHG emissions associated with CCS project pre-Crediting Period construction applied to Reporting Period **t** ($MTCO_2e$). Refer to Section 6.2.4. These emissions shall be calculated in the first Reporting Period of the first Crediting Period.
$PE_{Post-Inj_t}$	GHG emissions associated with CCS project monitoring, decommissioning, and closure in the post-injection period applied to Reporting Period **t** ($MTCO_2e$). Refer to Section 6.2.5. These emissions shall be calculated in the first Reporting Period of the first Crediting Period and accounted for in the same manner that pre-Crediting Period construction emissions ($\mathbf{PE_{Construct-Pre_t}}$) are accounted for

	(i.e., over the period **AP** and only during the first Crediting Period). If jurisdictional statutory or regulatory changes require additional post-injection period monitoring, decommissioning, or closure activities, those emissions shall be accounted for under $\mathbf{PE_{Post-Inj-Addl_t}}$.
AP	Period over which $\mathbf{PE_{Construct-Pre_t}}$ (pre-Crediting Period construction emissions and $\mathbf{PE_{Post-Inj_t}}$ (post-injection period monitoring, decommissioning, and closure emissions) are applied (years). This number shall be either 1 or 10 for non-EOR projects, and 1 or 5 for CO_2-EOR projects. If **AP** = 1, all $\mathbf{PE_{Construct-Pre_t}}$ and $\mathbf{PE_{Post-Inj_t}}$ shall be included in project emissions in Reporting Period 1. This number shall be chosen by the Project Proponent in the first Reporting Period and shall not be modified.
RP_t	Length of Reporting Period **t** (days).
Days	Days in the year (365 or 366).
$PE_{Construct-RP_t}$	GHG emissions associated with CCS project construction materials in Reporting Period **t** ($MTCO_2e$). Refer to Section 6.2.4.
$PE_{Post-Inj-Addl_t}$	GHG emissions associated with CCS project monitoring, decommissioning, and closure in the post-injection period applied to Reporting Period **t** that were not previously calculated as part of $\mathbf{PE_{Post-Inj_t}}$ ($MTCO_2e$). Refer to Section 6.2.5. These emissions shall only be accounted for in the first Reporting Period after a statutory or regulatory change requiring additional post-injection period monitoring, decommissioning, or closure activities goes into effect.
$CO_{2\,Atm\ Emissions-Inj_t}$	Total mass of CO_2 emitted to the atmosphere from the geologic storage reservoir in Reporting Period **t** during the injection period ($MTCO_2$). Refer to Section 6.2.7.
$PE_{Hydrocarbon_t}$	GHG emissions from produced hydrocarbons, including transport, processing and refining, and combustion (for CO_2-EOR projects)($MTCO_2e$). This value shall be equal to either $PE_{Hydrocarbon-U.S._t}$ or $PE_{Hydrocarbon-Canada_t}$. Refer to Section 6.2.6.

Equation 7 presents the approach to calculate captured CO_2 transferred outside the project boundary, which is assumed to be emitted. This transfer can occur at any point in the project.

Equation 7: Captured CO_2 Transferred Outside Project Boundary

$$PE_{Offsite\ CO_2\ Transfer_t} = Vol._{CO_2\ Transferred_t} \times \rho CO_2$$

WHERE

$PE_{Offsite\ CO_2\ Transfer_t}$	All captured CO_2 transferred outside the project boundary (i.e., not injected underground) in Reporting Period **t** ($MTCO_2$). This CO_2 is assumed to be emitted.
$Vol._{CO_2\ Transferred_t}$	Volume of captured CO_2 transferred outside the project boundary in any part of the project in Reporting Period **t** (m^3). Volume of CO_2 shall be measured at (or corrected to) standard conditions. This assumes a pure stream of CO_2. If the gas stream is not 100% CO_2, volume must be corrected by $\%CO_{2_t}$ (expressed as a decimal), which shall be measured continuously at a point relative to the gas volume measurement that allows for accurate measurement. This excludes CO_2 entrained in produced hydrocarbons and produced water, which is separately accounted for in Equation 24.
ρCO_2	Density of CO_2 at standard conditions = 0.001858 metric tons/m^3.

6.2.1 CO_2 CAPTURE, PROCESSING & COMPRESSION EMISSIONS

The following equation outlines the methods for calculating project emissions from the capture segment of the CCS project. This **excludes emissions associated with the primary CO_2 source(s)** and includes GHGs produced from all capture, processing, and compression equipment, including combustion GHGs, GHGs associated with the use of electricity and thermal energy produced offsite, and fugitive and vented GHGs. Some of the produced GHGs will be emitted to the atmosphere and some subset of the GHGs (i.e., CO_2) may be captured and injected underground as part of the project; when CO_2 is captured from any of this equipment, that equipment becomes a secondary CO_2 source.

Equation 8: Total Project Emissions from the Capture, Processing, and Compression Segment

$$PE_{Capture_t} = PE_{C-Comb_t} + PE_{C-Fug_t} + PE_{C-Vented_t}$$

WHERE

$PE_{Capture_t}$	Project emissions associated with all CO_2 capture, processing, and initial compression equipment in Reporting Period **t** ($MTCO_2e$).
PE_{C-Comb_t}	GHG emissions from combustion associated with all CO_2 capture, processing, and compression equipment in Reporting Period **t** ($MTCO_2e$). This excludes emissions associated with primary CO_2 source(s) but includes indirect emissions from offsite electricity used to operate the CO_2 source, capture, and compression equipment. Refer to Equation 9 through Equation 11.
PE_{C-Fug_t}	Fugitive GHG emissions (CO_2 and CH_4) from equipment associated with capture, processing, and compression equipment in Reporting Period **t** ($MTCO_2e$). This excludes fugitive emissions associated with primary CO_2 source(s). Refer to Equation 23.
$PE_{C-Vented_t}$	GHG emissions associated from the venting of GHGs from capture, processing, and compression equipment in Reporting Period **t** ($MTCO_2e$). This excludes venting emissions associated with primary CO_2 source(s). Refer to Equation 22.

Emissions quantification at the CO_2 capture site includes combustion and electric-drive units to support the capture, processing, and compression processes, such as cogeneration units, boilers, heaters, engines, and turbines. For example, the operation of a coal gasifier with a pre-combustion absorption capture unit and electric-drive compression would require an air separation unit to generate pure oxygen for the gasification process, a steam generation unit to supply heat to regenerate the CO_2-rich absorbent, and electricity to drive the compressors and other auxiliary equipment. These emissions sources are included within the capture boundary to quantify the energy use associated with the CO_2 capture process (which would not occur in the baseline scenario). Ultimately, GHG emissions from energy use will depend on the configuration of the capture, processing, and compression facilities, the types and quantities of fuels combusted, and electricity and thermal energy consumed during the capture, processing, and compression processes.

The following equations are used to quantify GHG emissions from combustion for relevant CCS project equipment in a specified segment,[51] plus GHG emissions associated with the use of offsite electricity and thermal energy to power equipment within the same project segment.

Equation 9: Project Emissions Associated with Combustion and Non-Combustion Energy Use

$$PE_{Comb_t} = \sum_{eq}\sum_{i}\left(Fuel_{i,eq,t} \text{ x } EF\ CO_{2_{Fuel_i}}\right) \text{ x } GWP_{CO_2} + \sum_{eq}\sum_{i}\left(Fuel_{i,eq,t} \text{ x } EF\ CH_{4_{Fuel_i}}\right) \text{ x } GWP_{CH_4} + \sum_{eq}\sum_{i}\left(Fuel_{i,eq,t} \text{ x } EF\ N_2O_{Fuel_i}\right) \text{ x } GWP_{N_2O} + \sum_{c} PE_{Flaring_{eq,t}} + \sum_{eq} PE_{Indirect\ Energy_{eq,t}}$$

WHERE

PE_{Comb_t}	Project emissions from combustion of fuels in all equipment associated with the relevant CCS project equipment in a specified segment,[52] as well as other, non-combustion energy produced to operate that equipment in Reporting Period **t** ($MTCO_2e$). This excludes emissions associated with primary CO_2 source(s).
$Fuel_{i,eq,t}$	Volume or mass of fuel type **i**, used to operate the specified equipment **eq** in Reporting Period **t** (e.g., m^3 or kg).
$EF\ CO_{2_{Fuel_i}}$	CO_2 emission factor for combustion of fuel **i** (e.g., $MTCO_2/m^3$ or tCO_2/kg of fuel).
$EF\ CH_{4_{Fuel_i}}$	CH_4 emission factor for combustion of fuel **i** (e.g., MT CH_4/m^3 or MT CH_4/kg of fuel).
$EF\ N_2O_{Fuel_i}$	N_2O emission factor for combustion of fuel **i** (e.g., MT N_2O/m^3 or MTN_2O/metric ton of fuel).

[51] e.g. capture, processing, and compression; transport; injection and storage; construction; decommissioning and closure

[52] e.g. capture, processing, and compression; transport; injection and storage; construction; monitoring, decommissioning, and closure

GWP_{CO_2}	GWP[53] of CO_2.
GWP_{CH_4}	GWP of CH_4.
GWP_{N_2O}	GWP of N_2O.
$PE_{Flaring_{eq,t}}$	Project emissions from the flaring of gases associated with all equipment **eq** in Reporting Period **t** ($MTCO_2e$). Refer to Equation 10.
$PE_{Indirect\ Energy_{eq,t}}$	Project emissions from offsite electricity and thermal energy used to operate equipment **eq** in Reporting Period **t** ($MTCO_2e$). Refer to Equation 11.

Equation 10: Project Emissions from Gas Flaring

$$\begin{aligned} PE_{Flaring_t} = & \sum_i \left(Gas\ Flared_{i,t} \times C_i \times y_{i,t} \times \frac{44.009}{0.0236904} \right) \times 10^{-6} \\ & + \sum_j \left(Flare\ Fuel_{j,t} \times EF\ CO_{2_{Flare\ Fuel_j}} \right) \times GWP_{CH_4} \\ & + \sum_i \left[Gas\ Flared_{i,t} \times (1 - 0.92) \times \%CH_{4_{i,t}} \times \rho CH_4 \right] \times GWP_{CH_4} \\ & + \sum_j \left[Flare\ Fuel_{j,t} \times (1 - 0.92) \times \%CH_{4_{j,t}} \times \rho CH_4 \right] \times GWP_{CH_4} \\ & + \sum_i \left(Gas\ Flared_{i,t} \times EF\ N_2O_{Gas\ Flared_i} \right) \times GWP_{N_2O} \\ & + \sum_j \left(Flare\ Fuel_{j,t} \times EF\ N_2O_{Flare\ Fuel_j} \right) \times GWP_{N_2O} \end{aligned}$$

WHERE

$PE_{Flaring_t}$	Project emissions from the flaring of gases associated with the relevant CCS project equipment in a specified segment in Reporting Period **t** ($MTCO_2e$). This excludes flaring emissions associated with primary CO_2 source(s).
$Gas\ Flared_{i,t}$	Volume of gas flared, by gas type **i** in Reporting Period **t** (m^3).

[53] All GWPs shall be applied as outlined in the *ACR Standard*.

$\text{Flare Fuel}_{j,t}$	Volume of each supplemental fuel, by fuel type **j**, used to ensure complete combustion of gases in Reporting Period **t** (m^3).
C_i	Number of carbon atoms would be assessed based on the chemical formula of each gas (e.g., 1 for CH_4, 1 for CO_2, 2 for C_2H_6)
$y_{i,t}$	Direct measurement of the mole fractions of each carbon-containing gas in gas mixture **i** in Reporting Period **t** (decimal fraction).
44.009	Reference value for molecular weight of CO_2 (g/mole).
0.0236904	Volume occupied by 1 mole of an ideal gas at standard conditions of 60 °F and 1 atmosphere (m^3).
10^{-6}	Conversion from grams to metric tons.
0.92	Destruction efficiency of flares.[54]
$\%CH_{4_{i\ or\ j,t}}$	Concentration of CH_4 in gas stream **i** or **j** that is being flared in Reporting Period **t** (%CH_4 by volume, expressed as a decimal).
ρCH_4	Density of CH_4 at standard conditions = 0.005921 metric tons/m^3.
$EF\ CO_{2_{\text{Flare Fuel}_j}}$	CO_2 emission factor for flare fuel **j** (e.g., $MTCO_2/m^3$ or $MTCO_2$/kg fuel).
$EF\ N_2O_{\text{Gas Flared}_i}$	N_2O emission factor for gas flared **i** (e.g., MT N_2O/m^3 or MT N_2O/kg fuel).
$EF\ N_2O_{\text{Flare Fuel}_j}$	N_2O emission factor for flare fuel **j** (e.g., MT N_2O/m^3 or MT N_2O/MT fuel).
GWP_{CO_2}	GWP of CO_2.
GWP_{CH_4}	GWP of CH_4.
GWP_{N_2O}	GWP of N_2O.

[54] The most conservative of the default flare destruction efficiencies (98%, 95%, and 92%) from (U.S. EPA, 2010b).

For CCS projects that generate thermal energy within the project boundary, Equation 9 shall be used. For projects utilizing electricity or thermal energy created offsite, Equation 11 shall be used. For some CCS project configurations, operation of the CO_2 capture, processing, and compression processes requires electricity and/or thermal energy from third parties (e.g., electric utilities, off-site co-generation facilities). Specifically, electricity might be used to operate compressors, dehydration units, refrigeration units, circulation pumps, fans, air separation units and a variety of other equipment. Thermal energy brought from offsite might be used for various purposes, including regeneration of the CO_2-rich absorbent used in some capture processes for a post-combustion capture configuration. Electricity might be sourced from direct-connected generating facilities or from the electricity grid, while thermal energy might be sourced from nearby steam generators or cogeneration facilities. Thermal energy and electricity might be sourced from separate facilities or sourced from the same combined heat and power generation (cogeneration) facility.

Equation 11: Project Emissions from Offsite Consumed Electricity and Thermal Energy

$$PE_{Indirect\ Energy_t} = \sum_{e}\left(Electricity_{e,t} \times EF_{Electricity_{e,t}}\right) + \sum_{h}\left(Thermal\ Energy_{h,t} \times EF_{Thermal\ Energy_h}\right)$$

WHERE

$PE_{Indirect\ Energy_t}$	Project emissions from offsite electricity and thermal energy used to operate the equipment for the relevant CCS project segment[55] in Reporting Period **t** ($MTCO_2e$).
$Electricity_{e,t}$	Metered offsite electricity source **e** used to operate relevant equipment in Reporting Period **t** (e.g., MWh, kWh).
$EF_{Electricity_{e,t}}$	Emission factor (for CO_2, CH_4, and N_2O) associated with offsite electricity source **e** used to operate relevant equipment in Reporting Period **t** (e.g., $MTCO_2e$/MWh). Refer to Appendix E for emission factor guidance.
$Thermal\ Energy_{h,t}$	Offsite thermal energy **h** used to operate relevant equipment in Reporting Period **t** (MMBtu)

[55] e.g., capture, processing, and compression; transport; injection and storage; construction; decommissioning and closure.

$EF_{Thermal\ Energy_h}$	Emission factor (for CO_2, CH_4, and N_2O) associated with offsite thermal energy **h** used to operate relevant equipment ($MTCO_2e$/MMBtu). The default value used for this emission factor shall be 0.0664 $MTCO_2e$/MMBtu.[56]

6.2.2 CO_2 TRANSPORT EMISSIONS

The GHG emissions quantification approach for the transport segment of a CCS project includes all transport emissions from the CO_2 receipt point from the point of capture (i.e., downstream of the CO_2 source) to the CO_2 transfer point at the injection and storage site, including the emission of CO_2 from natural CO_2-bearing formations when this CO_2 is part of the CCS project. The calculation methodology applies to CO_2 transported via pipelines or in containers (i.e., rail lines, roads, maritime ships, barges, intermodal transport). Some or all transport-related GHGs will be emitted to the atmosphere and some may be captured and injected underground as part of the project. When CO_2 is captured from any transport equipment, that equipment becomes a secondary CO_2 source and the captured CO_2 is accounted for in Equation 4 and Equation 6.The following equation shows how to calculate GHG emissions from the transport segment of a CCS project.

Equation 12: Total Project Emissions from the Transport Segment

$$PE_{Transport_t} = PE_{T-Pipeline-single_t} + PE_{T-Pipeline-mixed_t} + PE_{T-Mobile_t} + PE_{T-Vented\ CO_{2_t}}$$

WHERE

$PE_{Transport_t}$	Project emissions from CO_2 transport in Reporting Period **t** ($MTCO_2e$).
$PE_{T-Pipeline-single_t}$	GHG emissions from combustion of fuels in equipment used to operate all CO_2 pipelines with CO_2 only from this CCS project in Reporting Period **t** ($MTCO_2e$). This includes fuel and feedstock (including flaring) emissions as well as emissions associated with electricity used to operate the CO_2 pipeline and associated equipment. Refer to Equation 13. This term does not apply to CO_2 transport by rail, road, maritime ship, or barge.
$PE_{T-Pipeline-mixed_t}$	GHG emissions from combustion of fuels and venting associated with the equipment used to operate all CO_2 pipelines used by multiple parties in Reporting Period **t** ($MTCO_2e$). This includes direct fuel combustion

[56] Value calculated from CO_2, CH_4, and N_2O emission factors from Table 7 in (U.S. EPA, 2025a), using AR5 GWPs (IPCC, 2013).

	(including flaring) emissions as well as emissions associated with electricity used to operate the CO_2 pipeline and associated equipment. Refer to Equation 14. This term does not apply to CO_2 transport by rail, road, maritime ship, or barge.
$PE_{T-Mobile_t}$	GHG emissions from all mobile modes of transport (i.e., rail, road, maritime ship, barge) used to transport the CO_2 from capture site to the injection and storage site in Reporting Period **t** ($MTCO_2e$). Refer to Equation 16. This term does not apply to CO_2 transport by pipeline.
$PE_{T-Vented\ CO_{2t}}$	Vented CO_2 from all pipelines used only by this CCS project and mobile transport modes in Reporting Period **t** ($MTCO_2e$). Refer to Equation 22. This term does not apply to CO_2 transported via CO_2 pipelines used by multiple parties.

Combustion equipment that is a part of CO_2 pipeline could include equipment such as engines, turbines, and heaters. For some projects, compression may be required along the pipeline or at an interconnection with a pipeline that is operated at a higher pressure. Combustion emissions associated with energy inputs for CO_2 transport are quantified according to the following equation.

In some CCS project configurations, electricity may be utilized to operate CO_2 pipeline infrastructure. For example, electric-drive compressors may be used for supplemental compression along the CO_2 pipeline. The indirect emissions associated with offsite electricity for the CO_2 pipeline are also quantified according to the following equation.

Equation 13: Project Emissions Associated with CO_2 Pipelines Used Only by the CCS Project

$$PE_{T-Pipeline-single_t} = \sum_i (Fuel_{i,p,t} \times EF\ CO_{2_{Fuel_i}}) \times GWP_{CO_2} + \sum_i (Fuel_{i,p,t} \times EF\ CH_{4_{Fuel_i}}) \times GWP_{CH_4} + \sum_i (Fuel_{i,p,t} \times EF\ N_2O_{Fuel_i}) \times GWP_{N_2O} + PE_{T-Flaring_{p,t}} + PE_{T-Fug_{p,t}} + \sum_i (Electricity_{i,p,t} \times EF_{Electricity_{i,p,t}})$$

WHERE

$PE_{T-Pipeline-single_t}$	Project emissions from combustion of fuels associated with the operation of all CO_2 pipelines used only by the CCS project in Reporting Period **t** ($MTCO_2e$).
$Fuel_{i,p,t}$	Volume or mass of fuel type **i** used to operate CO_2 pipeline **p** used only by the CCS project in Reporting Period **t** (e.g., m^3 or kg).
$EF\ CO_{2_{Fuel_i}}$	CO_2 emission factor for combustion of fuel **i** (e.g., $MTCO_2/m^3$ or $MTCO_2/kg$ of fuel).
$EF\ CH_{4_{Fuel_i}}$	CH_4 emission factor for combustion of fuel **i** (e.g., MT CH_4/m^3 or MT CH_4/kg of fuel).
$EF\ N_2O_{Fuel_i}$	N_2O emission factor for combustion of fuel **i** (e.g., MT N_2O/m^3 or MT N_2O/ metric ton of fuel).
GWP_{CO_2}	GWP of CO_2.
GWP_{CH_4}	GWP of CH_4.
GWP_{N_2O}	GWP of N_2O.
$PE_{T-Flaring_{p,t}}$	Emissions from the flaring of gases associated with equipment supporting CO_2 transport segment (pipeline **p**) used only by the CCS project in Reporting Period **t** ($MTCO_2e$). Refer to Equation 10.

$PE_{T\text{-}Fug_{p,t}}$	Fugitive emissions associated with equipment supporting CO_2 pipeline **p** used only by the CCS project in Reporting Period **t** ($MTCO_2e$). Refer to Equation 23.
$Electricity_{i,p,t}$	Metered offsite electricity **i** used to operate all equipment associated with CO_2pipeline **p** used only by the CCS project in Reporting Period **t** (e.g., MWh, kWh).
$EF_{Electricity_{i,p,t}}$	Emission factor (for CO_2, CH_4, and N_2O) associated with all offsite electricity **i** used to operate equipment associated with CO_2 pipeline **p** used only by the CCS project in Reporting Period **t** (e.g., $MTCO_2e$/MWh). Refer to Appendix E for emission factor guidance.

For CO_2 pipelines that are used by multiple entities, it is highly unlikely that the Project Proponent will have enough information about total CO_2 pipeline throughput and GHG emissions to use pipeline-specific data to calculate associated transport emissions. Therefore, default emission factors shall be used.

Equation 14: Project Emissions Associated with CO_2 Pipelines Used by Multiple Parties

$$\mathbf{PE_{T-Pipeline-mixed_t}} = \sum_{q} \left[\left(\mathbf{Distance\ Pipeline_{q,t}} \right) \times \left(\mathbf{EF\ Pipeline\ Operation_{q,t}} + \mathbf{Pipeline\ Leakage_{CO_{2_{q,t}}}} \right) \times \mathbf{t/year} \right]$$

WHERE

$PE_{T-Pipeline_t}$	Project emissions associated with the operation of all CO_2 pipelines used by multiple parties in Reporting Period **t** ($MTCO_2e$).
$Distance\ Pipeline_{q,t}$	Distance traveled by CO_2 pipeline **q** used by multiple parties in Reporting Period **t** (miles or km).
$EF\ Pipeline\ Operation_{q,t}$	GHG emission factor—including direct combustion emissions, emissions associated with offsite electricity, and venting emissions—for the operation of CO_2 pipeline **q** used by multiple parties in Reporting Period **t** ($MTCO_2e$/mile per year or $MTCO_2e$/km per year).

$\text{Pipeline Leakage}_{CO_{2_{q,t}}}$	Pipeline emission factor for leakage of CO_2 from CO_2 pipeline **q** used by multiple parties in Reporting Period **t** ($MTCO_2e$/mile per year or $MTCO_2e$/km per year) = 14 $MTCO_2$/km per year or 23 $MTCO_2$/mile per year.[57]
t/year	Reporting period **t** length relative to 1 year. For instance, for a Reporting Period of 6 months, **t/year** = 0.5.

Equation 15: Metric Ton-Mile

$$\text{Metric ton-mile}_{r,t} = \sum_{prod} \left(\text{Mass product}_{prod,r,t} \times \text{Distance}_{prod,r,t}\right)$$

WHERE

$\text{Metric ton-mile}_{r,t}$	Distance traveled (in miles) by all products multiplied by the mass of all of those products (in metric tons) via each mobile transport mode **r** in Reporting Period **t** (metric ton-miles).
$\text{Mass Product}_{prod,r,t}$	Mass of product **prod** transported via mobile transport mode **r** in Reporting Period **t** (metric ton). **NOTE:** This includes the mass or weight of the container (e.g., CO_2 tank) plus the mass or weight of the contained product.
$\text{Distance}_{prod,r,t}$	Distance that product **prod** traveled via mobile transport mode **r** in Reporting Period **t** (miles).

Mobile source emissions for CO_2 transport by rail lines, roads, maritime ships, barges, or intermodal transport. are calculated by aggregating the metric ton-miles transported by each mode and multiplying the individual totals by an appropriate mode-specific emission factor. The following equations assume that CO_2 in mobile transport is in individual containers. Volumes must be measured at the input to the mobile transport mode and upon delivery to the injection and storage site to account for vented emissions. If mobile transport containers contain comingled eligible and ineligible CO_2,[58] the relative amounts of CO_2 (1) at input to the mobile transport mode and (2) at delivery to the

[57] Calculated from most conservative of the CO_2 pipeline fugitive emission factors (0.014 Gg CO_2/km per year) found in Volume 2 of IPCC (2006).

[58] i.e., CO_2 from eligible CO_2 sources and CO_2 from ineligible sources such as CO_2 sourced from natural CO_2-bearing formations.

injection and storage site must be measured and vented emissions (value (1) – value (2)) applied on a proportion basis: project CO_2 input into transport mode / total CO_2 input into transport mode * vented emissions. Total CO_2e emissions are calculated using the following equation.

Equation 16: Project Emissions from Mobile Transport

$$PE_{Mobile_t} = \sum_r \left(\text{Metric ton-mile}_{r,t} \times EF\ CO_{2_r} \times 10^{-3}\right) \times GWP_{CO_2} + \sum_r \left(\text{Metric ton-mile}_{r,t} \times EF\ CH_{4_r} \times 10^{-6}\right) \times GWP_{CH_4} + \sum_r \left(\text{Metric ton-mile}_{r,t} \times EF\ N_2O_r \times 10^{-6}\right) \times GWP_{N_2O}$$

WHERE

PE_{Mobile_t}	Project emissions from all modes of mobile transport that were used to transport products within (e.g., CO_2 transported from the capture site to the injection and storage site) or to (e.g., construction materials) the CCS project in Reporting Period **t** ($MTCO_2e$).
$\text{Metric ton-mile}_{r,t}$	Metric ton-miles for each mobile transport mode **r** (rail, truck, maritime ship, or barge) for products transported within (e.g., CO_2 transported from the capture site to the injection and storage site) or to (e.g., construction materials) the CCS project in Reporting Period **t** (metric ton-miles). Refer to Equation 15. **NOTE:** The metric ton-miles calculation includes the mass of the container (e.g., CO_2 tank) plus the mass of the contained product.
$EF\ CO_{2_r}$	CO_2 emission factor for mobile transport mode **r** (kg/metric ton-mile). Refer to Appendix E for emission factor guidance.
$EF\ CH_{4_r}$	CH_4 emission factor for mobile transport mode **r** (g/metric ton-mile). Refer to Appendix E for emission factor guidance.
$EF\ N_2O_r$	N_2O emission factor for mobile transport mode **r** (g/metric ton-mile). Refer to Appendix E for emission factor guidance.
GWP_{CO_2}	GWP of CO_2.
GWP_{CH_4}	GWP of CH_4.

GWP_{N_2O}	GWP of N_2O.

Equation 17: CO_2 Captured and Input into CO_2 Transport

$$\mathbf{CO_2\ Transferred_{Transpo_t}} = \sum_{c\&x} (\mathbf{Vol._{Gas\ Transferred_{c\&x,t}}} \times \mathbf{\%CO_{2_{c\&x,t}}}) \times \mathbf{\rho CO_2}$$

WHERE

$CO_2\ Transferred_{Transpo_t}$	Total CO_2 captured and transferred to the first CO_2 mode of transport in Reporting Period **t** ($MTCO_2$).
$Vol._{Gas\ Transferred_{c\&x,t}}$	Total volume of gas captured from CO_2 sources **c** and **x** located upstream of the first transfer to transport and input into the first mode of transport, measured at (or corrected to) standard conditions at the point of transfer to the first mode of transport, in Reporting Period **t** (m^3 gas).
$\%CO_{2_{Gas\ Transferred_{c\&x,t}}}$	Concentration of CO_2 in the gas stream from CO_2 sources **c** and **x** located upstream of the first transfer to transport, measured at the input to the first mode of transport, in Reporting Period **t** (%CO_2 by volume, expressed as a decimal). The concentration shall be measured at a location relative to $\mathbf{Vol._{Gas\ Transferred_{c\&x,t}}}$ that allows for accurate measurement.
ρCO_2	Density of CO_2 at standard conditions = 0.001858 metric tons/m^3.

Equation 18: CO_2 Transferred from CO_2 Pipelines to CO_2 Storage Sites

$$\mathbf{CO_2Transferred_{Storage_t}} = \sum_{p,r} \mathbf{Vol._{Gas\ Transferred_{p,r,t}}} \times \%\mathbf{CO_2} \times \boldsymbol{\rho}\mathbf{CO_2}$$

WHERE

$CO_2Transferred_{Storage_t}$	Total CO_2 transferred to the injection and storage site operator by all single-user CO_2 pipelines and mobile transport media in Reporting Period **t** ($MTCO_2e$). This term is only calculated and utilized in Equation 19 when all the CO_2 transferred to the injection and storage site comes from CO_2 sources upstream of the CO_2 transport segment of the project, the CO_2 is not intermingled with transport-related captured CO_2, and the CO_2 is not intermingled with captured CO_2 that is not associated with the CCS project.
$Vol._{Gas\ Transferred\ to\ Storage_{p,r,t}}$	Volume of gas that has been transferred to the injection and storage site operator by single-user CO_2 pipeline **p** and mobile transport mode **r** in Reporting Period **t** (m^3). Gas volume shall be measured at the point(s) of transfer to the injection and storage site at (or corrected to) standard conditions.
$\%CO_{2_t}$	Concentration of CO_2 in the gas stream measured at the point(s) of transfer to the storage site at a location relative to $Vol._{Gas\ Transferred\ to\ Storage_{p,r,t}}$ that allows for accurate measurement ($\%CO_2$ by volume, expressed as a decimal).[59]
ρCO_2	Density of CO_2 at standard conditions = 0.001858 metric tons/m^3.

[59] Composition of gas delivered to an injection and storage site is assumed to be same composition as the gas from the transportation segment.

Equation 19: Project Emissions from Fugitive and Vented CO_2 from Pipelines Used Only by this CCS Project and/or Other Mobile Transport Modes

$$PE_{T-Vented\ CO_{2_t}} = CO_2Transferred_{Transpo_{,t}} - CO_2\ Transferred_{Storage_t}$$

WHERE

$PE_{T-Vented\ CO_{2_t}}$	Project emissions from fugitive and vented CO_2 from all pipelines used only by this CCS project and/or mobile transport modes in Reporting Period **t** ($MTCO_2$). This term only applies in cases in which the CO_2 transferred to the injection and storage site comes from CO_2 sources upstream of the transport segment of the project and the CO_2 is *not* intermingled with captured CO_2 that is not associated with the CCS project (including when CO_2 is transported via pipelines used by multiple parties).
$CO_2\ Transferred_{Transpo_t}$	Total CO_2 captured and transferred to the first CO_2 transport mode in Reporting Period **t** ($MTCO_2$). Refer to Equation 17.
$CO_2Transferred_{Storage_t}$	Total CO_2 supplied to the injection and storage site operator by all single-user CO_2 pipelines and mobile transport modes Reporting Period **t** ($MTCO_2$). Refer to Equation 18.

6.2.3 CO_2 INJECTION, STORAGE, MONITORING & HYDROCARBON PRODUCTION AND ONSITE PROCESSING EMISSIONS

The emissions calculation procedures for CO_2 injection, storage, monitoring, and (for CO_2-EOR projects only) hydrocarbon production and (onsite) processing cover direct CO_2, CH_4, and N_2O emissions from combustion; CO_2 and CH_4 emissions from venting and fugitive releases to the atmosphere from equipment; indirect CO_2e emissions from offsite electricity and thermal energy. This includes all emissions sources located between the point of transfer from the CO_2 transport modes up to and including the injection wells (including injection wells for both CO_2 and any produced water) and any production wells within the injection site area of review, and includes the emission of CO_2 from natural CO_2-bearing formations. Some or all of the injection, storage, monitoring, and hydrocarbon production and onsite processing-related CO_2 will be emitted to the atmosphere and some may be captured and injected underground as part of the project. When CO_2 is captured from any equipment from his segment of the CCS project, that equipment becomes a secondary CO_2 source and the captured CO_2 is accounted for in Equation 4 and Equation 6.

Equation 20 outlines the methods for calculating emissions from CO_2 injection, storage, monitoring, and oil production and onsite processing.

Equation 20: Total Project Emissions from CO_2 Injection, Storage, Monitoring & Hydrocarbon Production and Onsite Processing

$$PE_{Storage_t} = PE_{S\text{-}Comb_t} + PE_{S\text{-}Vent_t} + PE_{S\text{-}Fug_t} + PE_{S\text{-}Entrained_{CO_{2_t}}}$$

WHERE

$PE_{Storage_t}$	Project emissions associated with CO_2 injection, storage, monitoring, and hydrocarbon production and onsite processing in Reporting Period **t** ($MTCO_2e$).
$PE_{S\text{-}Comb_t}$	Emissions from combustion of fuels in and use of electricity to power equipment for CO_2 injection, storage, monitoring, and hydrocarbon production and onsite processing (the latter for CO_2-EOR projects only) in Reporting Period **t** ($MTCO_2e$). This includes but is not limited to equipment used to maintain and operate the CO_2 handling and injection wells; monitoring equipment; and (for CO_2-EOR projects) GHG emissions associated with production wells; hydrocarbon gathering, onsite processing, and storage; CO_2 and produced water processing and recycling; and produced water reinjection. Refer to Equation 21.
$PE_{S\text{-}Vent_t}$	Emissions from venting of GHGs associated with CO_2 injection, storage, monitoring, and hydrocarbon production and onsite processing (the latter for CO_2-EOR projects only) operations in Reporting Period **t** ($MTCO_2e$). For CO_2-EOR projects, this also includes vented GHG emissions associated with production wells; hydrocarbon gathering, onsite processing, and storage; CO_2 and produced water processing and recycling; and produced water reinjection. Refer to Equation 22.
$PE_{S\text{-}Fug_t}$	Fugitive emissions at the injection wells and other surface facilities located between the point of transfer from the CO_2 transport segment and the AoR Boundary in Reporting Period **t** ($MTCO_2e$). For CO_2-EOR projects this also includes fugitive GHG emissions GHG emissions associated with production wells; hydrocarbon gathering, onsite

	processing, and storage; CO_2 and produced water processing and recycling; and produced water reinjection. Refer to Equation 23.
$PE_{S\text{-}Entrained_{CO_{2}t}}$	CO_2 entrained or dissolved in crude oil and other hydrocarbons and produced water that has been sold or otherwise transferred offsite in Reporting Period **t** ($MTCO_2$). Calculated based on quantities of crude oil, water and gas produced and the CO_2 content of each product ($MTCO_2$). Refer to Equation 24. This *excludes* CO_2 accounted for in **$\text{Captured Secondary } CO_{2_{x,t}}$** (refer to Equation 4).

Various types of equipment may be used to maintain and operate CO_2 injection, storage, monitoring, and hydrocarbon production and onsite processing operations (e.g., batteries, gathering and recycling systems, oil-water-gas separators). The following equation is used to quantify GHG emissions from all equipment used to maintain and operate equipment associated with CO_2 injection, storage, monitoring, hydrocarbon production and onsite processing.

Offsite electricity and/or thermal energy may be used to operate pumps, compressors, and other equipment at the injection site. For CO_2-EOR projects, this can also include producing wells; oil and gas gathering equipment, storage, and processing facilities (e.g., oil-water-gas separators); and CO_2 and produced water processing, compression, recycling, and re-injection facilities. For example, many CO_2-EOR projects install additional water pumping capacity to alternate water injection and CO_2 injection (water-alternating-gas injection), which may also require electricity. Electric compression could be used to recycle produced CO_2, other gases, and produced water for re-injection into the formation. In addition to the recycle compressors, additional electric-drive equipment may be used to operate vapor recovery units to recover gasses from oil and water tanks, to operate flash gas compressors which increase the pressure of the recovered vapors for recycling, to operate glycol dehydrators and glycol circulation pumps that remove moisture from the produced gas, and to operate other auxiliary equipment such as instrument air compressors and cooling fans.

Equation 21: Project Emissions from Combustion Associated with Injection, Storage, Monitoring & Hydrocarbon Production and Onsite Processing

$$PE_{S-Comb_t} = \sum_g \sum_i (Fuel_{i,g,t} \times EF\ CO_{2_{Fuel_i}}) \times GWP_{CO_2} + \sum_g \sum_i (Fuel_{i,g,t} \times EF\ CH_{4_{Fuel_i}}) \times GWP_{CH_4} + \sum_g \sum_i (Fuel_{i,g,t} \times EF\ N_2O_{Fuel_i}) \times GWP_{N_2O} + \sum_g PE_{S-Flaring_{g,t}} + \sum_g PE_{S-Indirect\ Energy_{g,t}}$$

WHERE

PE_{S-Comb_t}	Project emissions from the use of equipment associated with all injection, storage, monitoring, and hydrocarbon production and onsite processing activities (the latter for CO_2-EOR projects only) in Reporting Period **t** ($MTCO_2e$).
$Fuel_{i,g,t}$	Volume or mass of fuel type **i** used to inspect, maintain, and operate the CO_2 injection and storage infrastructure and oil production and onsite processing facilities (if applicable) at geologic storage reservoir **g** in Reporting Period **t** (e.g., m^3 or kg).
$EF\ CO_{2_{Fuel_i}}$	CO_2 emission factor for combustion of fuel **i** (e.g., $MTCO_2/m^3$ or $MTCO_2/kg$ of fuel). Refer to Appendix E for emission factor guidance.
$EF\ CH_{4_{Fuel_i}}$	CH_4 emission factor for combustion of fuel **i** (e.g., MT CH_4/m^3 or MT CH_4/kg of fuel). Refer to Appendix E for emission factor guidance.
$EF\ N_2O_{Fuel_i}$	N_2O emission factor for combustion of fuel **i** (e.g., MT N_2O/m^3 or MT N_2O/kg of fuel). Refer to Appendix E for emission factor guidance.
GWP_{CO_2}	GWP of CO_2.
GWP_{CH_4}	GWP of CH_4.
GWP_{N_2O}	GWP of N_2O.

$PE_{S-Flaring_{g,t}}$	Project emissions from the flaring of gases at geologic storage reservoir **g** in Reporting Period **t** ($MTCO_2e$). Refer to Equation 10.
$PE_{S-Indirect\ Energy_{g,t}}$	Project emissions associated with the use of offsite electricity and thermal energy at geologic storage reservoir **g** in Reporting Period **t** ($MTCO_2e$). Refer to Equation 11.

Venting of GHGs (e.g., fuel, CH_4, CO_2) from equipment may occur in various project segments, but especially in the CO_2 capture, processing and compression segment and the injection, storage, monitoring and hydrocarbon production and onsite processing segment. Venting can occur from compression equipment, from injection wells, and at other locations and from other equipment. For CO_2-EOR projects, venting can occur at production wells or at facilities used to process and recycle the produced CO_2 for re-injection into the formation. Planned venting may take place during shutdowns and maintenance work, while unplanned venting may occur during upsets to operations. Venting events shall be logged and gas concentrations reported.

The following equation can be used to calculate vented emissions from project equipment.

Equation 22: Project Emissions from Venting

$$PE_{Seg\text{-}Vent_t} = \sum_j \sum_i N_{Blowdown_{i,t}} \times V_{Blowdown_{i,t}} \times \%GHG_{j,t} \times \rho_{GHG_j} \times GWP_j$$

WHERE

$PE_{Seg\text{-}Vent_t}$	Project emissions from venting of GHG emissions in project segment **seg** in Reporting Period **t** ($MTCO_2e$).
$N_{Blowdown_{i,t}}$	Number of blowdowns for equipment **i** in Reporting Period **t**, obtained from blowdown event logs.
$V_{Blowdown_{i,t}}$	Total volume of blowdown equipment chambers for equipment **i** (including pipelines, manifolds, and vessels between isolation valves) in Reporting Period **t** (m^3). Refer to Appendix C.
$\%GHG_{j,t}$	Concentration of GHG **j** (CO_2 and CH_4) in the vented substance in Reporting Period **t** (%GHG by volume, expressed as a decimal).

ρ_{GHG_j}	Density of GHG **j** (CO_2 and CH_4) at conditions in the blowdown chamber (metric tons/m^3). At standard conditions, ρ_{CO_2} = 0.001858 metric tons/m^3 and ρ_{CH_4} = 0.005921 metric tons/m^3).
GWP_j	GWP of GHG **j** (CO_2 and CH_4).

Fugitive GHG emissions from injection wells and other surface equipment are calculated on a component count approach. Component-level sources include but are not limited to valves, connectors, flanges, pressure relief devices, open-ended lines, and compressors using population-based emission factors based on the project's geographic location. A population emission factor represents an average emission rate per component (e.g., scf CH_4/hour/valve) derived from field measurements across equipment populations. These are applied in combination with component counts to estimate emissions from petroleum and natural gas systems where direct measurement is infeasible.

The following equation is used to calculate fugitive emissions from the equipment and other surface facilities and can be applied where applicable.

Equation 23: Project Emissions from Equipment Leaks (i.e., Fugitive Emissions)

$$PE_{Seg-Fug_t} = \sum_s \sum_j \left(Count_{s,t} \times EF_s \times T_{s,t} \times \%GHG_{j,s,t} \times \rho_{GHG_j} \times GWP_j \right)$$

WHERE

$PE_{Seg-Fug_t}$	Project emissions from fugitive GHG emissions (CO_2 and CH_4) from equipment in a specified project segment **seg** (C = capture, processing & compression; T = transport, S = injection, storage, monitoring & hydrocarbon production and onsite processing) in Reporting Period **t** ($MTCO_2e$).
$Count_{s,t}$	Total number of each type of emission source **s** (e.g., wells, equipment) in the applicable project segment in Reporting Period **t**. If the number of emission sources varies during the Reporting Period, this number shall include all emission sources (i.e., the maximum number) that were present during that Reporting Period.
EF_s	Population emission factor for the specific fugitive emission source **s**. Refer to Appendix C.4.

$T_{s,t}$	Total time that the equipment associated with emission source **s** in the applicable project segment was operational in Reporting Period **t** (hours). Where equipment hours are unknown, this value shall equal the number of hours in the Reporting Period.
$\%GHG_{j,s,t}$	Concentration of GHG **j** (CO_2 and CH_4) in equipment **s** in Reporting Period **t** (%GHG by volume, expressed as a decimal).
ρ_{GHG_j}	Density of GHG **j** (CO_2 and CH_4) at conditions in the blowdown chamber (metric tons/m^3). At standard conditions, ρ_{CO_2} = 0.001858 metric tons/m^3 and ρ_{CH_4} = 0.005921 metric tons/m^3).
GWP_j	GWP of GHG **j** (CO_2 and CH_4).

CO_2 entrained in fluids produced during oil production is typically processed and reinjected (recycled) into the geologic storage reservoir at CO_2 injection wells. The methodology does not treat CO_2 produced from wells at EOR sites that is recycled and re-injected into the storage formation as an emission, provided the CO_2 remains within the closed loop system and is thus prevented from entering the atmosphere. Produced and reinjected CO_2 quantities shall be tracked and accounted for to ensure no double counting. Unintentional CO_2 releases from the recycle system (including from production wells, gas separation and cleaning equipment) are treated as fugitive emissions and accounted for in Equation 24 since they occur downstream of the last CO_2 measurement point. Intentionally vented CO_2 in the recycling system is treated as a vented emission and accounted for in Equation 22.

Equation 24 accounts for the CO_2 and CH_4 that is not separated from the hydrocarbons or water, reinjected into the storage reservoir, used elsewhere, or otherwise transported outside of the project boundary. This excludes CO_2 transported outside of the project boundary that is accounted for under other equations (e.g., $PE_{S\text{-}Offsite\ CO_2 Transfer_t}$ in Equation 7).

Equation 24: Project Emissions from CO_2 Entrained in Produced Hydrocarbons and Produced Water (EOR Projects Only)

$$\begin{aligned}PE_{S\text{-}Entrained_{CO_{2}t}} &= \sum_{g}\left(Vol._{Hydrocarbon\ Gas_{g,t}} \times \%CO_{2\ Hydrocarbon\ Gas_{g,t}}\right) \times \rho CO_2 \\ &+ \sum_{g}\left(Mass_{Water\ Prod_{g,t}} \times Mass\ Frac_{CO_2\ in\ Water_{g,t}}\right) \\ &+ \sum_{g}\left(Mass_{Oil\ Prod_{g,t}} \times Mass\ Frac_{CO_2\ in\ Oil\ Prod_{g,t}}\right) \\ &+ \sum_{g}\left(Mass_{Water\ Prod_{g,t}} \times Mass\ Frac_{Vented\ CH_4\ in\ Water\ Prod_{g,t}} \times GWP_{CH_4}\right) \\ &+ \sum_{g}\left(Mass_{Oil\ Prod_{g,t}} \times Mass\ Frac_{Vented\ CH_4\ in\ Oil\ Prod_{g,t}}\right) \times GWP_{CH_4}\end{aligned}$$

WHERE

$PE_{S\text{-}Entrained_{CO_{2}t}}$	Project emissions from CO_2 entrained or dissolved in all gas and fluids (hydrocarbon gas, produced water, and crude oil and other liquid hydrocarbons) that have been produced from all geologic storage reservoirs and are sold or otherwise transferred offsite in Reporting Period **t** ($MTCO_2$).
$Vol._{Hydrocarbon\ Gas_{g,t}}$	Volume of hydrocarbon gas, measured at (or corrected to) standard conditions, produced from geologic storage reservoir **g** that is sold or otherwise transported outside the project boundary in Reporting Period **t** (m^3). This excludes CO_2 accounted for in $PE_{Offsite\ CO_2\ Transfer_t}$ (see Equation 7).
$\%CO_{2\ Hydrocarbon\ Gas_{g,t}}$	Concentration of CO_2 in hydrocarbon gas produced from geologic storage reservoir **g** that is sold or otherwise transported outside the project boundary in Reporting Period **t** ($\%CO_2$ by volume, expressed as a decimal). This shall be measured at a point relative to $Vol._{Hydrocarbon\ Gas_{g,t}}$ that allows for accurate measurement.
ρCO_2	Density of CO_2 at standard conditions = 0.001858 metric tons/m^3.

$Mass_{Water\ Prod_{g,t}}$	Mass of water produced from geologic storage reservoir **g** that contains entrained CO_2 that is sold to, otherwise transported outside the project boundary, or otherwise not re-injected back into the formation, in Reporting Period **t** (MT). This assumes a closed loop system. If CO_2 concentrations are lower when water is re-injected than when it is extracted from the formation, the CO_2 must be measured and reported. If operators are using a closed loop water handling system, proponents may assume that CO_2 is being captured and therefore not an emission.
$Mass\ Frac_{CO_2\ in\ Water_{g,t}}$	Mass fraction of CO_2 in the water produced from geologic storage reservoir **g** in Reporting Period **t** (decimal fraction).
$Mass_{Oil\ Prod_{g,t}}$	Mass of crude oil and other liquid hydrocarbons produced from geologic storage reservoir **g** in Reporting Period **t** (MT).
$Mass\ Frac_{CO_2\ in\ Oil\ Prod_{g,t}}$	Mass fraction of CO_2 in the crude oil and other liquid hydrocarbons produced from geologic storage reservoir **g** in Reporting Period **t** (decimal fraction).
$Mass\ Frac_{Vented\ CH_4\ in\ Water\ Prod_{g,t}}$	Mass fraction of CH_4 in the water produced from geologic storage reservoir **g**, from which the gases are vented to the atmosphere, in Reporting Period **t** (decimal fraction).
$Mass\ Frac_{Vented\ CH_4\ in\ Oil\ Prod_{g,t}}$	Mass fraction of CH_4 in the crude oil and other liquid hydrocarbons produced from geologic storage reservoir **g**, the gases from which are vented to the atmosphere, in Reporting Period **t** (decimal fraction).

Measuring the mass of CO_2 injected underground is critical for ensuring the integrity, safety, and accountability of geologic storage projects. For example, under U.S. EPA's Class VI regulations, accurate quantification of injected CO_2 is required to demonstrate compliance with the injection limits established in the approved permit, support ongoing site characterization and modeling, and verify that injected CO_2 remains within the designated injection zone. Reliable measurement is also essential for transparent reporting and shall be accounted for using the following equation (U.S. EPA, 2010a).

Equation 25: CO_2 Injected Underground at the CO_2 Injection & Storage Site

$$\mathbf{CO_2Injected_{g,t}} = \sum_{g}\sum_{w}\left(\mathbf{Mass_{Injected_{w,g,t}}}\right)$$

WHERE

$CO_2\ Injected_{g,t}$	Total CO_2 injected into wells in all geologic storage reservoirs **g**, measured at the surface point of injection, in Reporting Period **t** ($MTCO_2$).
$Mass_{Injected_{w,g,t}}$	Mass of CO_2 injected into injection well **w** in geologic storage reservoir **g**, measured at the surface point of injection, in Reporting Period **t** (MT).

6.2.4 CONSTRUCTION EMISSIONS

GHG emissions from the construction of infrastructure directly involved in CO_2 capture, transport, and storage is included within the project boundary. These construction-related emissions include onsite emissions (e.g., fuel combustion from construction machinery), construction-related transport emissions, and the production of certain high-GWP building materials (namely, cement, asphalt, and steel).

Construction emissions may relate to multiple Reporting Periods as part of the same project and therefore may be amortized and allocated to Reporting Periods. As noted in Equation 6, the Project Proponent may apply pre-Crediting Period construction project emissions either to the first Reporting Period or apply them on a proportional basis over the first Crediting Period using the term $PE_{Construct-Pre_t}$ in Equation 6. Construction emissions that occur within a Reporting Period shall be calculated using the term $PE_{Construct-RP_t}$.

Construction emissions associated with the transport of equipment and materials for construction activities include mobile source emissions for equipment and material transport from point of origin to the construction site by barge, rail, truck and construction equipment sources (cranes, fork trucks, dozers, and loaders) used for material handling, and small personal transport modes used to move material (and personnel) and equipment within and around the project site during construction. Construction emissions associated with energy usage during construction activities include the use of both electricity and fuel.

Equation 26: Total Project Emissions from Pre-Crediting Period Construction

$$\mathbf{PE_{Construct-Pre} = PE_{Construct-Pre-Transpo} + PE_{Construct-Pre-Comb} + PE_{Construct-Pre-Materials}}$$

WHERE

$PE_{Construct-Pre}$	Total project emissions associated with CCS project pre-Crediting Period construction ($MTCO_2e$).
$PE_{Construct-Pre-Transpo}$	GHG emissions from all mobile modes of transport (i.e., rail, road, maritime ship, barge) used to transport construction materials and equipment to all parts of the CCS project before the Crediting Period ($MTCO_2e$). Refer to Equation 16.
$PE_{Construct-Pre-Comb}$	GHG emissions from combustion of fuels in and use of electricity to power equipment associated with all part of the CCS project before the Crediting Period (MCO_2e). Refer to Equation 28.
$PE_{Construct-Pre-Materials}$	GHG emissions from production of construction materials for the CCS project before the Crediting Period ($MTCO_2e$). Refer to Equation 29.

Equation 27: Total Project Emissions from Construction During a Reporting Period

$$\mathbf{PE_{Construct-RP_t} = PE_{Construct-RP-Transpo_t} + PE_{Construct-RP-Comb_t} + PE_{Construct-RP-Materials_t}}$$

WHERE

$PE_{Construct-RP_t}$	GHG emissions associated with CCS project construction materials in Reporting Period **t** ($MTCO_2e$).
$PE_{Construct-RP-Transpo_t}$	GHG emissions from all mobile modes of transport (i.e., rail, road, maritime ship, barge) used to transport construction materials and equipment to all parts of the CCS project in Reporting Period **t** ($MTCO_2e$). Refer to Equation 16.
$PE_{Construct-RP-Comb_t}$	GHG emissions from non-transport-related combustion of fuels in and use of electricity to power construction equipment associated with all

	part of the CCS project in Reporting Period **t** ($MTCO_2e$). Refer to Equation 28.
$PE_{Construct-RP-Materials_t}$	GHG emissions from production of construction materials for the CCS project in Reporting Period **t** ($MTCO_2e$). Refer to Equation 29.

Various types of equipment may be used to maintain and operate construction equipment (e.g., loaders, well-drilling rigs). The following equation is used to quantify GHG emissions from all equipment used to maintain and operate construction equipment.

Equation 28: Project Emissions from Non-Transport-Related Combustion of Fuels to Operate Construction Equipment

$$
\begin{aligned}
PE_{Construct-RP-Comb_t} &= \sum_{eq}\sum_{i}\left(Fuel_{i,eq,t} \times EF\ CO_{2_{Fuel_{i,eq}}}\right) \times GWP_{CO_2} \\
&+ \sum_{eq}\sum_{i}\left(Fuel_{i,eq,t} \times EF\ CH_{4_{Fuel_{i,eq}}}\right) \times GWP_{CH_4} \\
&+ \sum_{eq}\sum_{i}\left(Fuel_{i,eq,t} \times EF\ N_2O_{Fuel_{i,eq}}\right) \times GWP_{N_2O} + \sum_{eq} PE_{S-Flaring_{eq,t}} \\
&+ \sum_{eq} PE_{S-Indirect\ Energy_{eq,t}}
\end{aligned}
$$

WHERE

$PE_{Construct-RP-Comb_t}$	Project emissions from non-transport-related combustion of fuels in and use of electricity to power construction equipment associated with all part of the CCS project in Reporting Period **t** ($MTCO_2e$).
$Fuel_{i,eq,t}$	Volume or mass of fuel type **i** used to operate construction equipment **eq** in Reporting Period **t** (e.g., m^3, kg).
$EF\ CO_{2_{Fuel_{i,eq}}}$	CO_2 emission factor for combustion of fuel **i** in equipment **eq** (e.g., $MTCO_2/m^3$ or $MTCO_2$/kg of fuel). Refer to Appendix E for emission factor guidance.
$EF\ CH_{4_{Fuel_{i,eq}}}$	CH_4 emission factor for combustion of fuel **i** in equipment **eq** (e.g., MT CH_4/m^3 or MT CH_4/kg of fuel). Refer to Appendix E for emission factor guidance.

$\text{EF N}_2\text{O}_{\text{Fuel}_{i,eq}}$	N_2O emission factor for combustion of fuel **i** in equipment **eq** (e.g., MT N_2O/m^3 or MT N_2O/kg of fuel). Refer to Appendix E for emission factor guidance.
GWP_{CO_2}	GWP of CO_2.
GWP_{CH_4}	GWP of CH_4.
GWP_{N_2O}	GWP of N_2O.
$PE_{S-Flaring_{eq,t}}$	Project emissions from the flaring of gases used to operate construction equipment **eq** in Reporting Period **t** ($MTCO_2e$). Refer to Equation 10.
$PE_{S-Indirect\ Energy_{eq,t}}$	Project emissions associated with the use of offsite electricity and thermal energy used to operate construction equipment **eq** in Reporting Period **t** ($MTCO_2e$). Refer to Equation 11.

For construction materials, the emission factors found in Table 6 shall be used if these materials have been used to build the CCS project.

Equation 29: Project Emissions from the Production of Construction Materials

$$\mathbf{PE_{Construct-RP-Materials_t}} = \sum_{m} (\mathbf{Mass_{m,t}} \times \mathbf{Material\ EF_{m,t}}) + \left(\sum_{Pipeline} \mathbf{Mass_{Pipeline,t}} \times \mathbf{Material\ EF_{Pipeline,t}} \times \mathbf{\%Throughput_{Pipeline}} \right)$$

WHERE

$PE_{Construct-RP-Materials_t}$	Project emissions associated with the production of all construction materials for the CCS project in Reporting Period **t**, before the start of the Crediting Period, or anticipated to be used during the post-injection period, as applicable ($MTCO_2e$).
$Mass_{m_t}$	Mass or weight of material **m** (see the materials listed in Table 6 and steel as specified in Table 19) brought into use at the CCS project in Reporting Period **t**, before the start of the Crediting Period, or anticipated to be used during the post-injection period, as applicable

	(e.g., kg, g, lb.). If the material is steel utilized for a pipeline and pipeline compressors, the term $Mass_{Pipeline,t}$ shall be used.
$Material\ EF_{m,t}$	Emission factor for the production of material **m** utilized in the CCS project in Reporting Period **t**, before the start of the Crediting Period, or anticipated to be used during the post-injection period, as applicable ($MTCO_2e$ per unit mass or weight). Refer to Table 6 and Table 19 for construction material emission factors.
$Mass_{Pipeline,t}$	Mass or weight of CO_2 pipeline and pipeline compressor material **Pipeline** brought into use at the CCS project in Reporting Period **t** or before the start of the Crediting Period, as applicable (e.g., kg, g, lb.). This value shall only be calculated for pipelines and pipeline compressors that were newly installed for use in the CCS project.
$Material\ EF_{Pipeline,t}$	Emission factor for the production of CO_2 pipeline and pipeline compressor material **Pipeline** utilized in the CCS project in Reporting Period **t** or before the start of the Crediting Period, as applicable ($MTCO_2e$ per unit mass or weight). Refer to Table 19 for pipeline construction material emission factors.
$\%Throughput_{Pipeline}$	Maximum expected throughput of the CO_2 pipeline relative to the design capacity (%, expressed as a decimal). Maximum expected throughput is the highest CCS project-related volume of CO_2 expected to be transported in the pipeline over the Crediting Period. If the pipeline will be a single-user pipeline with throughput only from CCS project-related CO_2, this value shall be 1.

The following emission factors shall be used if the materials have been used to build the CCS project.

Table 6: Emission Factors for the Production of Construction Materials

MATERIAL	EMISSION FACTOR
CEMENT	0.886 $MTCO_2$ per MT cement.[60]
ASPHALT MIXTURE	0.0521 $MTCO_2e$ per short ton of asphalt mix.[61]
STEEL	Refer to Table 19.

6.2.5 POST-INJECTION PERIOD MONITORING, DECOMMISSIONING & CLOSURE EMISSIONS

GHG emissions associated with post-injection monitoring, decommissioning, and closure are included within the project boundary. These emissions include those expected to occur from onsite fuel use and the use of offsite energy used for onsite activities, deconstruction activities and related transport, as well as the use of monitoring equipment, during the post-injection period. After injection ceases, the stored CO_2 must be monitored to ensure it remains within the geologic storage reservoir (see Section 7.3.12). Decommissioning and closure activities include plugging wells, dismantling infrastructure, restoring sites, transporting project-related equipment and materials to the sites of decommissioning and closure and other post-project locations (e.g., disposal facility, new project site), use of deconstruction and closure equipment (e.g., cranes, fork trucks, dozers, loaders), and use of personal vehicles associated with post-injection period activities. Decommissioning includes the shutdown and deconstruction of any facilities associated with capture at the CO_2 source as well as the injection and storage site. These emissions shall be conservatively calculated during the first Reporting Period of the first Crediting Period. If, after the first Reporting Period of the first Crediting Period, a statutory or regulatory changes require additional post-injection period monitoring, decommissioning, or closure activities, these emissions shall be conservatively calculated and

[60] Total cement kiln CO_2 emissions from fuel combustion and from the calcination of limestone (process emissions) at clinker production (cement) plants, calculated from plant data reported to U.S. EPA and including only plants with continuous emissions monitoring systems (CEMS), and adjusted to account for materials blended with the clinker. Emissions from biogenic fuels, methane (CH_4), and nitrous oxide (N_2O) were excluded, as the emissions for all were <1% for most plants using CEMS. Value listed is the highest value (25th percentile) in the report (U.S. EPA, 2021)

[29] Highest emission factor for materials (A1), transportation of materials to processing facility (A2, and asphalt mix production (A3) over the period 2009-2019 (Shacat et al., 2022). The highest emission factor occurred in 2016.

accounted for in the first Reporting Period after the statutory or regulatory change goes into effect. Project Proponents shall reference closure and decommissioning requirements of the relevant jurisdiction(s) to ensure that the conservative calculations reflect all major GHG emissions sources of jurisdictionally required activities for the post-injection period. Post-injection period monitoring, decommissioning, and closure project emissions shall be quantified using the following equation.

Equation 30: Total Post-Injection Period Monitoring, Decommissioning, and Closure Project Emissions

$$\mathbf{PE_{Post-Inj}}\ or\ \mathbf{PE_{Post-Inj-Addl}} = \mathbf{PE_{Post-Inj-Transpo}} + \mathbf{PE_{Post-Inj-Comb}} + \mathbf{PE_{Construct-Materials}}$$

WHERE

$PE_{Post-Inj}$	GHG emissions associated with CCS project monitoring, decommissioning, and closure in the post-injection period ($MTCO_2e$). These emissions shall be calculated during the first Reporting Period of the first Crediting Period and accounted for according to the schedule in Equation 6.
$PE_{Post-Inj-Addl}$	GHG emissions associated with CCS project monitoring, decommissioning, and closure in the post-injection period that weren't calculated as part of $\mathbf{PE_{Post-Inj}}$ ($MTCO_2e$). These emissions shall only be accounted for in the first Reporting Period after a statutory or regulatory change requires additional post-injection period monitoring, decommissioning, or closure activities.
$PE_{Post-Inj-Transpo}$	GHG emissions from all mobile modes of transport (i.e., rail, road, maritime ship, barge) used to transport decommissioning and closure equipment to and from CCS project sites and used to transport materials offsite in the post-injection period ($MTCO_2e$). Refer to Equation 16.
$PE_{Post-Inj-Comb}$	Emissions from combustion of fuels in and use of offsite energy to power equipment associated with monitoring equipment, decommissioning, and closure of all affected parts of the CCS project in the post-injection period ($MTCO_2e$). Refer to Equation 21.
$PE_{Construct-Materials}$	GHG emissions associated with the production of all construction materials used for the CCS project during decommissioning and closure, as applicable ($MTCO_2e$). Refer to Equation 29.

6.2.6 PRODUCED OIL & ASSOCIATED GAS EMISSIONS (CO_2-EOR ONLY)

In addition to oil production emissions accounted for in Section 6.2.3, emissions from transport, refining and processing, and end use of produced oil and associated gas must be accounted for as project emissions and included in any Reporting Period during which oil and associated hydrocarbon production from CO_2-EOR occurs. These emissions shall be included in any Reporting Period during which oil and associated gas production occurs. Equation 31 presents the approach to calculate GHG emissions from oil and associated gas produced by projects storing CO_2 in the U.S., and Equation 34 for projects storing CO_2 in Canada.

Equation 31: Project Emissions from Produced Oil & Associated Gas (U.S.)

$$\mathbf{PE_{Hydrocarbon-U.S._t}} = \sum_{g} \left[\mathbf{Vol.\,Crude\;U.S._{g,t}} \times \left(\mathbf{EF_{Hydrocarb-Transpo_{g,t}}} + \mathbf{EF_{Hydrocarb-Refining_{g,t}}} + +\mathbf{EF_{Hydrocarb-End\;Use_{g,t}}} \right) \times \mathbf{0.001} \right] + \mathbf{PE_{Assoc.Gas-U.S._t}}$$

WHERE

$PE_{Hydrocarbon-U.S._t}$	Transport, refining and processing, and end use project emissions from all oil and associated gas produced in the U.S. in Reporting Period **t** ($MTCO_2e$).
$Vol.\,Crude\;U.S._{g,t}$	Volume of crude oil produced from U.S. geologic storage reservoir **g** in Reporting Period **t**, measured immediately before custody transfer to another entity and before shipment offsite of the CO_2 storage location (bbl).
$EF_{Oil-Transpo_{g,t}}$	Emission factor for the transport of oil produced from U.S. geologic storage reservoir **g** during Reporting Period **t**, including from the CO_2 injection and storage site to refinery or processing facility, refinery or processing facility to distribution center, and transport of crude oil or the end product to where it is used/combusted—whether that be a domestic or international destination ($kgCO_2e/bbl$). Directions on calculation of this emission factor can be found in Equation 32 and Appendix B, Section B.1.

$EF_{Oil-Refining_{g,t}}$	Emission factor for refining of oil produced from U.S. geologic storage reservoir **g** during Reporting Period **t** ($kgCO_2e/bbl$). Refer to Appendix B, B.2, or provide refinery-specific emission factors. If calculating project-specific refining emissions, Project Proponents must supply documentation to the VVB detailing refinery-specific emission factors.
$EF_{Oil-End\ Use_{g,t}}$	Emission factor for end use (combustion) of the petroleum products created from the oil produced from U.S. geologic storage reservoir **g** during Reporting Period **t** ($kgCO_2e/bbl$). Refer to Appendix B, Section B.3.
$PE_{Assoc.Gas-U.S._t}$	Transport, processing, and end use project emissions from all associated gas produced from U.S. geologic storage reservoirs in Reporting Period **t** ($MTCO_2e$). Refer to Equation 33.
0.001	Conversion factor to convert from kg to metric tons.

Equation 32: Emissions from Transport of Oil & Refined Products (U.S.)

$$\mathbf{EF_{Oil-Transpo_{g,t}}} = \sum_{g} \Big(\mathbf{EF_{Oil-Transpo-Refinery_{g,t}}} + \mathbf{EF_{Oil-Transpo-Crude-Export_{g,t}}} + \mathbf{EF_{Oil-Transpo-Terminals_{g,t}}} + \mathbf{EF_{Oil-Refined-Export_{g,t}}} \Big) \times \mathbf{0.001}$$

WHERE

$EF_{Oil-Transpo_t}$	Emission factors for the transport of oil produced from U.S. geologic storage reservoir **g** during Reporting Period **t**, including from CO_2 injection and storage site to refinery, refinery to wholesale terminal, and transport of crude oil or refined product to where it is used/combusted—whether that be a domestic or international destination ($kgCO_2e/bbl$). Directions on calculation of this emission factor can be found in Appendix B, Section B.1 or use project-specific transport emission factors. If calculating project-specific transport emissions by following the crude oil after it leaves the storage facility, instead of using default factors, Project Proponents must provide chain of

	custody tracking to show distances traveled and mode of transportation (this will be unlikely for most projects).
$EF_{Oil-Transpo-Refinery_{g,t}}$	Emission factor for transport of crude oil produced from U.S. geologic storage reservoir **g** to refineries during Reporting Period **t** (kgCO_2e/bbl). Directions on calculation of this emission factor can be found in Appendix B, Section B.1A.
$EF_{Oil-Transpo-Crude-Export_{g,t}}$	Transport emission factor for the export of crude oil produced from U.S. geologic storage reservoir **g** during Reporting Period **t** (kgCO_2e/bbl). Directions on calculation of this emission factor can be found in Appendix B, Section B.1B.
$EF_{Oil-Transpo-Terminals_{g,t}}$	Emission factor for the domestic transport of refined oil for which the crude oil was produced from U.S. geologic storage reservoir **g** to wholesale terminals during Reporting Period **t** (kgCO_2e/bbl). Directions on calculation of this emission factor can be found in Appendix B, Section B.1C.
$EF_{Oil-Transpo-Refined-Export_{g,t}}$	Transport emission factor for the export of refined oil for which the crude oil was produced from U.S. geologic storage reservoir **g** during Reporting Period **t** (kgCO_2e/bbl). Directions on calculation of this emission factor can be found in Appendix B, Section B.1D.
0.001	Conversion factor to convert from kg to metric tons.

Equation 33: Project Emissions from Associated Gas (U.S.)

$$PE_{Assoc.Gas-U.S._t} = \sum_{g} \left(Assoc.\,Gas\,U.S._{g,t} \times EF_{Assoc.Gas-U.S._t} \times 0.001 \right)$$

WHERE

$PE_{Assoc.Gas-U.S._t}$	Transport, processing, and end use project emissions from all associated gas produced from U.S. geologic storage reservoirs in Reporting Period **t** (MTCO_2e).

$\text{Assoc. Gas U.S.}_{g,t}$	Volume of associated gas produced from U.S. geologic storage reservoir **g** in Reporting Period **t**, measured immediately before custody transfer to another entity and before shipment offsite of the CO_2 storage location (scf). The emission factor calculation is optional if using R&D GREET (Argonne National Laboratory, 2025), but the measured volume of associated gas must be used as an input to the GREET model.
$EF_{\text{Assoc.Gas-U.S.}_t}$	Emission factor for the transport, offsite processing, and end use of associated gas produced from U.S. geologic storage reservoir **g** during Reporting Period **t** ($kgCO_2e$/scf). Refer to Table 19 for more details.
0.001	Conversion factor to convert from kg to metric tons.

Equation 34: Project Emissions from Produced Oil & Associated Gas (Canada)

$$PE_{\text{Hydrocarbon-Canada}_t} = \sum_{g}\left(\text{Assoc. Gas Canada}_{g,t} \times EF_{\text{Assoc. Gas-Canada}_t} \times 0.001\right) + \sum_{g}\left(\text{Vol. Crude Canada}_{g,t} \times EF_{\text{Oil-Canada}_{g,t}} \times 0.001\right)$$

WHERE

$PE_{\text{Hydrocarbon-Canada}_t}$	Transport, refining and processing, and end use project emissions from all oil and associated gas produced in Canada Reporting Period **t** ($MTCO_2e$).
$\text{Assoc. Gas Canada}_{g,t}$	Volume of associated gas produced from Canadian geologic storage reservoir **g** in Reporting Period **t**, measured immediately before custody transfer to another entity and before shipment offsite of the CO_2 storage location (scf).
$EF_{\text{Assoc. Gas-Canada}_t}$	Emission factor for the transport, offsite processing, and end use of associated gas produced from Canadian geologic storage reservoir **g** during Reporting Period **t** ($kgCO_2e$/scf). Refer to Table 19 for more details. The emission factor calculation is optional if using R&D GREET

	(Argonne National Laboratory, 2025), but the measured volume of associated gas must be used as an input to the GREET model.
$\text{Vol. Crude Canada}_{g,t}$	Volume of crude oil produced from Canadian geologic storage reservoir **g** in Reporting Period **t**, measured immediately before custody transfer to another entity and before shipment offsite of the CO_2 storage location (bbl).
$EF_{Oil-Canada_{g,t}}$	Emission factor for the transport, refining, and end use of crude oil produced from Canadian geologic storage reservoir **g** during Reporting Period **t** ($kgCO_2e/bbl$). Refer to Table 19 for more details. The emission factor calculation is optional if using R&D GREET (Argonne National Laboratory, 2025), but the measured volume of crude oil must be used as an input to the GREET model.
0.001	Conversion factor to convert from kg to metric tons.

6.2.7 GEOLOGIC STORAGE RESERVOIR EMISSIONS

Project Proponents must demonstrate that there is a (are) competent confining zone(s) that will prevent the emission of CO_2 from the storage volume in the geologic storage reservoir. Injected CO_2 shall be monitored during the entire Minimum Project Term, which includes the injection period and post-injection period defined in Section 4.3.4 using monitoring requirements outlined in Section 7.3 and any jurisdiction permits.

If CO_2 migrates from the geologic storage reservoir and the migration is not remediated in time to prevent emissions to the atmosphere, Project Proponents shall quantify the CO_2 emissions on a site-by-site basis according to a reasonable engineering approach. This shall involve computations that incorporate a range of information about the specific AoR and geologic storage reservoir, the CO_2 injection regime, modeling assumptions, and other variables. The injection and storage site operator has the best knowledge of site-specific conditions and shall combine this knowledge with sound engineering practices to calculate CO_2 emissions reaching the atmosphere, should that occur. This includes the use of conservative factors and algorithms in their calculations. Further, the uncertainty in the calculated value shall be determined and included in the calculations to ensure conservativeness. In the event of containment failure, a simplified calculation to conservatively determine maximum emissions can be used with Equation 35 and Equation 36.

The following general equations that account for CO_2 emissions from the storage volume reproduce a formula from U.S. EPA's Greenhouse Gas Reporting Program (U.S. EPA, 2010a; U.S. EPA, 2010d). It directs injection and storage site operators to identify emission pathways from the subsurface and aggregate total emissions from each CO_2 emission pathway, should a leak be detected. For the purposes of this Methodology, CO_2 shall be considered to have been emitted to the atmosphere if the CO_2 plume or the pressure front is observed (either directly or indirectly) at unmitigated pathways to the surface, including but not limited to unplugged or inappropriately plugged wells that penetrate the confining zone(s), or if CO_2 or the elevated pressure front is detected within a monitoring well.

If the calculated emissions exceed the ERRs calculated for that Reporting Period (refer to Section 6.3 for calculation of ERRs), it shall be compensated for per the procedures outlined in the ACR CCS Project Reversal Risk Mitigation Contract.

Equation 35: Emissions from the CO_2 Storage Volume During the Injection Period

$$CO_{2_{\text{Atm Emissions}-\text{Inj}_t}} = \sum_g \sum_z CO_{2_{z,g,t}}$$

WHERE

$CO_{2_{\text{Atm Emissions}-\text{Inj}_t}}$	Total mass of CO_2 emitted to the atmosphere from geologic storage reservoir(s) in Reporting Period **t** during the injection period ($MTCO_2$).
$CO_{2_{z,g,t}}$	Total mass of CO_2 emitted through pathway **z** in geologic storage reservoir **g** in Reporting Period **t** ($MTCO_2$).

Equation 36 is used to report emission of CO_2 to the atmosphere that occurs after the injection period. Mitigation and compensation of post-injection emissions from the geologic storage reservoirs is discussed in Section 9.

Equation 36: Emissions from the CO_2 Storage Volume During the Post-Injection Period

$$CO_{2_{\text{Atm Emissions}-\text{Post}}} = \sum_g \sum_z CO_{2_{z,g,post}}$$

WHERE

$CO_{2_{\text{Atm Emissions}-\text{Post}}}$	Total mass of CO_2 emitted to the atmosphere from geologic storage reservoir(s) during the post-injection period ($MTCO_2$).
$CO_{2_{z,g,post}}$	Total mass of CO_2 emitted through pathway **z** in geologic storage reservoir **g** during the post-injection period **post** ($MTCO_2$).

6.3 GHG Emission Reductions and Removals (ERRs)

This section describes the process of determining Total and Net GHG Emission Reductions and Removals for a Reporting Period for which a valid Verification Report has been accepted by ACR.

The following equation shall be used to quantify Total GHG Emission Removals and Reductions from the CCS project.

Equation 37: Total Emission Reductions and Removals

$$\text{GHG ERR}_t = \text{BE}_t - \text{PE}_t$$

WHERE

GHG ERR_t	Total GHG emission reductions and removals from the CCS project in Reporting Period **t** ($MTCO_2e$).[62]
BE_t	Baseline CO_2e emissions in Reporting Period **t** ($MTCO_2e$). Refer to Equation 1 or Equation 5.
PE_t	Project CO_2e emissions in Reporting Period **t** ($MTCO_2e$). Refer to Equation 6.

The following equation shall be used to quantify the required contribution to ACR Reserve Account for the Reporting Period.

Equation 38: Reserve Account Contribution

$$\text{RA}_t = \text{GHG ERR}_t \times \text{RA\%}_t$$

WHERE

RA_t	Reserve Account Contribution required for Reporting Period **t** ($MTCO_2e$).
GHG ERR_t	Total GHG emission reductions and removals from the CCS project in Reporting Period **t** ($MTCO_2e$). Refer to Equation 37.

[62] Most CCS projects will have all GHG removals or all GHG reductions. If any projects have a mix, the emission reductions and removals shall be proportional to the amount of CO_2 captured from each removal-eligible source and each reduction-eligible source.

$RA\%_t$	Percent of the Total Emission Reductions and Removals for Reporting Period **t** that must be contributed to the ACR Reserve Account, as determined by the ACR CCS Reserve Account Contribution Tool (%).

The following equation shall be used to quantify the Net GHG Emission Reductions and Removals (i.e., the ERTs issued to the Project Proponent).

Equation 39: Net Emission Reductions and Removals

$$\mathbf{NET\ ERR_t = GHG\ ERR_t - RA_t}$$

WHERE

$NET\ ERR_t$	Net GHG Emission Reductions and Removals from the CCS project in Reporting Period **t** ($MTCO_2e$).
$GHG\ ERR_t$	Total GHG emission reductions and removals from the CCS project in Reporting Period **t** ($MTCO_2e$). Refer to Equation 37.
RA_t	Reserve Account Contribution required for reporting Period **t** ($MTCO_2e$). Refer to Equation 38.

Net GHG Emission Reductions and Removals and Reserve Account Contribution for Reporting Period **t** shall be prorated by vintage year using the following equations. The quantities are prorated by the number of calendar days within a given calendar year covered by the Reporting Period.

Equation 40: Net Emission Reductions and Removals by Vintage

$$\mathbf{NET\ ERR_{t,v} = NET\ ERR_t \times \left(\sum_g CO_2\ Injected_{g,v} \Big/ \sum_g CO_2\ Injected_{g,t} \right)}$$

WHERE

$NET\ ERR_{t,v}$	Net GHG Emission Reductions and Removals from the CCS project in Reporting Period **t** assigned to vintage year **v** ($MTCO_2e$).
$NET\ ERR_t$	Net GHG Emission Reductions and Removals from the CCS project in Reporting Period **t** ($MTCO_2e$). Refer to Equation 39.

$CO_2\ Injected_{g,v}$	CO_2 injected into wells in all geologic storage reservoirs **g**, measured at the surface point(s) of injection, in vintage year **v** ($MTCO_2$).
$CO_2\ Injected_{g,t}$	CO_2 injected into wells in all geologic storage reservoirs **g**, measured at the surface point(s) of injection, in Reporting Period **t** ($MTCO_2$). Refer to Equation 25.

Equation 41: Reserve Account Contribution by Vintage

$$RA_{t,v} = RA_t \times \left(\sum_g CO_2\ Injected_{g,v} \Big/ \sum_g CO_2\ Injected_{g,t} \right)$$

WHERE

$RA_{t,v}$	Reserve Account Contribution required for Reporting Period **t** assigned to vintage year **v** ($MTCO_2e$).
RA_t	Reserve Account Contribution required for Reporting Period **t** ($MTCO_2e$). Refer to Equation 38.
$CO_2\ Injected_{g,v}$	CO_2 injected into wells in all geologic storage reservoirs **g**, measured at the surface point(s) of injection, in vintage year **v** ($MTCO_2$).
$CO_2\ Injected_{g,t}$	CO_2 injected into wells in all geologic storage reservoirs **g**, measured at the surface point(s) of injection, in Reporting Period **t** ($MTCO_2$). Refer to Equation 25.

6.4 Leakage

There is no activity-shifting leakage or market leakage associated with this project type. Leakage was considered for the components of eligible project activities discussed in this section.

Leakage from the CO_2 source type "natural gas processing facility" is prevented through the requirement that natural gas processing facilities must process natural gas from oil and/or gas reservoirs with historical (i.e., pre-2021) production or, if the natural gas is from a newly produced reservoir, demonstrating that the natural gas production would have been financially viable without the benefit of revenue from carbon credits. This ensures that the Methodology does not incentivize the production of natural gas from new, potentially higher CO_2-content gas that would not otherwise be extracted.

CO_2-EOR enables the production of fossil fuels that contribute to GHG emissions but, due to the project activity of CCS, the oil produced from these reservoirs has a lower carbon footprint relative to other oil production. Emissions from the production, transport, refining and processing, and end use of any produced oil and associated gas are accounted for within the project emissions. The production from the CO_2-EOR eligible under this methodology does not impact the market demand for, or use of, fossil fuels.

CCS involving CO_2 originally stored in biomass (i.e., BECCS and BiCRS) removes CO_2 from the atmosphere and permanently stores it in geologic storage reservoirs. Leakage is prevented through the methodology's eligibility criteria requiring that projects utilize only sustainable biomass, as defined in Appendix D, including guarding against land use change and market distortion that could otherwise be a source of leakage.

Zero- (or near-zero) GHG emissions electricity sources may be used by a CCS project and reduce the project emissions through the application of custom electricity emission factors. To ensure against resource shuffling of purchased electricity, the custom electricity emission factors are only allowed for when the electricity is sourced from a newly constructed electricity generator.

6.5 Uncertainty

The calculations of baseline and project emissions in this methodology are designed to ensure conservativeness and prevent overestimation of GHG emission reductions and removals, taking into account potential uncertainties. While the uncertainty is low, it can be associated with CO_2 source operating parameters, fluid flow and composition analysis of gas and liquid streams, geologic storage reservoir emission events maintained by site operators and emission factors. The sources and relative magnitude of uncertainties (and changes thereof) shall be quantified where possible and explicitly addressed by the Project Proponent in the GHG Project Plan.

Uncertainty could arise if the introduction of the CO_2 capture changes the emissions and/or productivity at the CO_2 source through a shift in the operating parameters. The methodology addresses this uncertainty and ensures conservativeness through requirements for functional equivalence and the corresponding adjustment factor in the project-based baseline (Equation 1). The adjustment factor is not applied in the intensity-based baseline (Equation 5) because that baseline is not affected by the addition of capture to a CO_2 source. Projects in which a primary CO_2 source is subject to an emission intensity metric or limit must calculate both types of baselines and use the most conservative baseline one.

Key inputs in quantification, such as fluid flow and composition analysis of gas and liquid streams, are metered and measured data. The accuracy and precision of measurement equipment such as flow meters, gas composition analyzers, and process measurements (i.e., electricity and thermal energy) must be checked and maintained on a regular schedule (per Section 7.2) to minimize uncertainty of these data. The methodology provides missing data substitution procedures that ensure conservativeness (refer to Appendix F).

Other site operator data such as emissions from blowdown events and fugitive emission losses depend on meticulous logs maintained by the operator, consistent with U.S. federal reporting requirements (Subpart W; U.S. EPA, 2010b).

Well-designed, site-specific MRV plans with ongoing monitoring requirements, as required in Section 7, enable detection and calculation of CO_2 emissions from the geologic storage reservoir and compensation procedures, as discussed in Section 9, ensure the permanence and certainty of emission reductions and removals from CCS projects.

Finally, default values such as emission factors provided in this methodology are selected for accuracy, representativeness, and conservativeness. Where project-specific emission factors are allowed, they must meet rigorous criteria for data sources in Appendix E to ensure their appropriateness.

7 Monitoring and Data Collection

7.1 Data Collection and Parameters to Be Monitored

This section provides information about specific parameters that shall be monitored to calculate GHG emission reductions from a CCS project according to the quantification procedures in Section 6. Project Proponents shall incorporate this information into their project-specific measurement, reporting and verification (MRV) plan and adapt it to accommodate the specific conditions associated with their CCS project.

Data collection and monitoring is essential to ensure the validity of GHG emission reduction and removal claims. Table 7 aggregates the specific monitoring parameters and activities needed for a comprehensive assessment of the GHG emission reductions or removals that might be claimed by a Project Proponent. Project Proponents shall consider the location, type of equipment, and frequency of measurement for each variable. Instructions for calibration and other measurement and monitoring equipment requirements are discussed in Section 7.2.

In addition to the parameters in Table 7, Project Proponents shall provide and the VVB shall review the following materials provided by the Project Proponent. These materials shall be provided each Reporting Period unless otherwise specified below:

- MRV Plan (submitted once with the GHG Project Plan, validated, and updated as required as an appendix to the Monitoring Report) as outlined in Section 7.3;
- The Project Proponent shall implement and maintain documented procedures for collecting, verifying, and reporting output data used to apply the intensity-based metric in baseline emissions calculations, where applicable. These procedures must ensure the data is accurate and consistent with the metric's scope and units.
- The Project Proponent shall provide the source for the regulatory or other legally enforceable emissions intensity metric utilized for Equation 5 and justification for its applicability and use (submitted once with the GHG Project Plan, validated, and updated through a Monitoring Report where appropriate).
- The VVB shall confirm the regulatory or other legally enforceable emission intensity metric, evaluate its applicability to the CO_2 source type, confirm consistency of functional units, review

the project's data collection and reporting procedures, and validate the application of the emissions intensity metric. Where the Reporting Period involves a new calendar year, the VVB must verify that the intensity-based benchmark is still appropriate;

- Metering and monitoring procedures;
- Any conversion or normalization factors applied;
- Copies of approved project-related permits active during the Reporting Period;
- Copies of reports provided to any underground injection well permitting;
- Documentation indicating that all sites where CCS project activities are occuring have been in regulatory compliance. If there are periods of non-compliance, the date(s) and nature of non-compliance, remedial actions taken, and the date(s) when the site returns to compliance shall be documented and provided during verification. If there are periods of non-compliance, then the effect of non-compliance on the quantified emission reductions shall be evaluated and, if necessary, the creditable emission reductions shall be reduced (refer to Equation 3 and Equation 4);
- Environmental Assessment or Environmental Impact Statement (provided once and providing updated copies as applicable), if required by the jurisdictional authority; and
- Evidence proving financial responsibility by the operator, as required by applicable law, regulation, or other legal requirement, prior to gaining a permit to begin active CO_2 injection operations and prior to site closure.

Table 7: Monitoring Parameters

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
			PROJECT-BASED BASELINE		
$Vol._{Primary\ Gas\ Captured_{c,t}}$	Total volume of gas (containing CO_2 and other compounds) produced and captured from CO_2 source **c** in Reporting Period **t** during periods of air permit(s) compliance and during periods of air permit non-compliance during which no excess CO_2 was produced.	m^3	M	Continuous[64]	Measured continuously at (or corrected to) standard conditions and metered at a point immediately downstream of the point of CO_2 capture. For eligible DAC, BECCS, and BiCRS projects, this amount shall be equal to the amount of CO_2 removed from the atmosphere.
$Vol._{Primary\ Excess\ Gas_{c,t}}$	Volume of excess CO_2 gas produced from CO_2 source **c** due to permit violations (if any) in Reporting Period **t**.	m^3	M & C	Continuous	Measured continuously at (or corrected to) standard conditions at a point immediately downstream of the point of CO_2 capture. This value is a subset of $Vol._{Primary\ Gas\ Captured_{c,t}}$. This shall include both official violations and any self-reported exceedances.

[63] Parameter types: C = calculated, M = measured, O = operating records.

[64] Measurement taken at least every 15 minutes.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
$\%CO_{2_{c,t}}$	Concentration of CO_2 in the gas stream from primary CO_2 source **c** in Reporting Period **t**.	$\%CO_2$ by volume, expressed as a decimal	M	Continuous or monthly	Measured at a point immediately downstream of the point of CO_2 capture and in relation to $Vol._{Primary\ Gas\ Captured_{c,t}}$ and $Vol._{Primary\ Excess\ Gas_{c,t}}$ in a location that allows for accurate measurement.[65]
$Vol._{Secondary\ Gas\ Captured_{x,t}}$	Total volume of gas (containing CO_2 and other compounds) produced and captured from secondary CO_2 source **x** in Reporting Period **t** during periods of air permit(s) compliance and during periods of air permit non-compliance during which no excess CO_2 was produced.	m^3	M	Continuous	Measured continuously at (or corrected to) standard conditions at a point immediately downstream of the point of CO_2 capture.
$Vol._{Secondary\ Excess\ CO_{2_{x,t}}}$	Volume of excess CO_2 gas produced from secondary CO_2 source **x** due to air permit	m^3	M & C	Continuous	Measured continuously at (or corrected to) standard conditions at a point immediately downstream of the point of CO_2 capture (m^3). This value is a subset of

[65] e.g., where gas stream flow is laminar, meaning flow is not cyclonic or turbulent; no new flow is introduced like cooling air.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
	violations[66] (if any) in Reporting Period **t**.				$Vol._{Secondary\ Gas\ Captured_{x,t}}$. The exceedances shall include both official violations and any self-reported exceedances.
$\%CO_{2_{x,t}}$	Concentration of CO_2 in the gas stream from secondary CO_2 source **x** in Reporting Period **t**.	$\%CO_2$ by volume, expressed as a decimal	M	Continuous or monthly	Measured at a point immediately downstream of the point of CO_2 capture and in relation to $Vol._{Secondary\ Gas\ Captured_{x,t}}$ and $\mathbf{Vol._{Secondary\ Excess\ CO_{2_{x,t}}}}$ in a location that allows for accurate measurement.
INTENSITY-BASED BASELINE					
$\mathbf{Output_{c,t}}$	Total production unit of output of the CO_2 source **c** in the project condition, in Reporting Period **t**.	e.g., MWh, MMscf	M, C	Continuous to Daily	Measurement based on the units of the legally enforceable intensity metric for the CO_2 source.

[66] As well as during periods of air permit non-compliance during which no excess CO_2 was produced.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
PROJECT GHG EMISSIONS					
$Vol._{CO_2 Transferred_t}$	Volume of captured CO_2 transferred outside the project boundary in any part of the project in Reporting Period **t**.	m^3	M	Continuous	Volume of CO_2 shall be measured at (or corrected to) standard conditions. If the gas stream is not 100% CO_2, volume must be corrected by $\%CO_{2_t}$ (expressed as a decimal), which shall be measured continuously at a point relative to the gas volume measurement that allows for accurate measurement. This excludes CO_2 entrained in produced hydrocarbons and produced water.
CAPTURE, PROCESSING & COMPRESSION SEGMENT					
$Fuel_{i,eq,t}$	Volume or mass of fuel type **i** used to operate the specified equipment **eq** in Reporting Period **t**.	e.g., m^3, kg	M, O, C	Daily or monthly	For gaseous fuels, daily measurement of the gas flow rate. For liquid and solid fuels, monthly reconciliation of purchasing records with inventory adjustments as needed are acceptable. For liquid and solid fuels, volume or mass measurements are commonly made upon purchase or delivery of the

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
					fuel. Reconciliation of purchase receipts or weigh scale tickets are an acceptable means to determine the quantities of fuels consumed.
$Gas\ Flared_{i,t}$	Volume of gas flared by gas type **i** in Reporting Period **t**.	m^3	M	Continuous	Gas volume shall be measured at the flare. Gas volume shall be measured at (or corrected to) standard conditions.
$Flare\ Fuel_{j,t}$	Volume of each supplemental fuel by fuel type **j** used to ensure complete combustion of gases in Reporting Period **t**.	m^3	M, O, C	Daily or monthly	For gaseous fuels, daily measurement of the gas flow rate. For liquid and solid fuels, monthly reconciliation of purchasing records and inventory adjustments are acceptable. For liquid and solid fuels, volume or mass measurements are commonly made upon purchase or delivery of the fuel. Reconciliation of purchase receipts or weigh scale tickets are an acceptable means to determine the quantities of fuels consumed.
$y_{i,t}$	Direct measurement of the mole fractions of each	decimal fraction	M	Continuous or monthly	Measured using gas chromatograph.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
	carbon-containing gas in gas mixture **i** in Reporting Period **t**.				
$\%CH_{4_{i\ or\ j,t}}$	Concentration of CH_4 in the gas stream **i** or **j** that is being flared in Reporting Period **t**.	$\%CH_4$ by volume, expressed as a decimal	M	Continuous or monthly	Measured at the input to the flare system.
$\textbf{Electricity}_{e,t}$	Metered offsite electricity source **e** used to operate all the equipment associated with the capture, processing & compression segment, in Reporting Period **t**.	e.g., MWh, kWh	M, O	Continuous or monthly	Continuous measurement of electricity consumption or monthly billing records from utility supplier, or see $\textbf{Electrical Rating}_{i,t}$, $\textbf{Hours}_{i,t}$, and $\textbf{Load}_{i,t}$ in the "Alternative Quantification Methods" subsection of Table 7 (below) for an alternative way to calculate electricity using reconciliation of maximum kW rating for each type of equipment and operating hours.
$\textbf{Thermal Energy}_{h,t}$	Offsite thermal energy **h** used to operate relevant equipment associated with	MMBtu	M, O	Daily or monthly	Measured daily using a utility meter or measured monthly via invoices from the thermal energy provider

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
	the capture, processing & compression segment in Reporting Period **t**.				showing the quantity of thermal energy supplied.
$Count_{s,t}$	Total number of each type of emission source **s** (e.g., wells, equipment) in the capture, processing & compression segment in Reporting Period **t**.	#	O, C	Once per Reporting Period	Operator shall develop and maintain an equipment inventory to identify all possible fugitive emission sources from surface facilities and equipment in this segment. If the number of emission sources varies during the Reporting Period, this number shall include all emission sources (i.e., the maximum number) that were present during that Reporting Period.
$T_{s,st}$	Total time that the equipment associated with emission source **s** in the capture, processing & compression segment that was operational in Reporting Period **t**.	hours	M, O, C	Monthly or once per Reporting Period	Measured or estimated based on operational records and downtime of the equipment in the capture, processing & compression segment. Where equipment hours are unknown, this value shall equal the number of hours in the Reporting Period.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
$\%GHG_{j,s,t}$	Concentration of GHG **j** (CO_2 and CH_4) in equipment **s** in the capture, processing & compression segment in Reporting Period **t**.	%GHG by volume, expressed as a decimal	M	Continuous or monthly	Direct measurement of the composition of the gas stream.
$N_{Blowdown_{i,t}}$	Number of blowdowns for equipment **i** in Reporting Period **t**, obtained from blowdown event logs.	#	O, C	As occurs	Operators shall keep detailed logs of all venting incidents.
$V_{Blowdown_{i,t}}$	Total volume of blowdown equipment chambers for equipment **i** (including pipelines, manifolds, and vessels between isolation valves) associated with the capture, processing & compression segment in Reporting Period **t**.	m^3	O, C	Once per Reporting Period	Volume can be estimated based on equipment specifications (e.g., pipeline diameters), flow meters, and duration of event. Refer to Appendix C.
$\%GHG_{j,t}$	Concentration of GHG **j** (CO_2 and CH_4) in the vented substance in Reporting Period **t**.	%GHG by volume, expressed	M	Continuous or as occurs	Direct measurement of the composition of the gas stream at the venting location.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
		as a decimal			
TRANSPORT SEGMENT					
$Fuel_{i,p,t}$	Volume or mass of fuel type **i** used to operate CO_2 pipeline **p** used only by the CCS project in the transport segment in Reporting Period **t**.	e.g., m^3, kg	M, O, C	Daily or monthly	For gaseous fuels, daily measurement of the gas flow rate. For liquid and solid fuels, monthly reconciliation of purchasing records and inventory adjustments are acceptable. For liquid and solid fuels, volume or mass measurements are commonly made upon purchase or delivery of the fuel. Reconciliation of purchase receipts or weigh scale tickets are an acceptable means to determine the quantities of fuels consumed.
$Gas\ Flared_{i,t}$	Volume of gas flared by gas type **i** in Reporting Period **t**.	m^3	M	Continuous	Gas volume shall be measured at the flare. Gas volume shall be measured at (or corrected to) standard conditions.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
$Flare\ Fuel_{j,t}$	Volume of each supplemental fuel by fuel type **j** used to ensure complete combustion of the gases in Reporting Period **t**.	m^3	M, O, C	Daily or monthly	For gaseous fuels, daily measurement of the gas flow rate. For liquid and solid fuels, monthly reconciliation of purchasing records and inventory adjustments are acceptable. For liquid and solid fuels, volume or mass measurements are commonly made upon purchase or delivery of the fuel. Reconciliation of purchase receipts or weigh scale tickets are an acceptable means to determine the quantities of fuels consumed.
$y_{i,t}$	Direct measurement of the mole fractions of each carbon-containing gas in gas mixture **i** in Reporting Period **t**.	decimal fraction	M	Continuous or monthly	Measured using gas chromatograph.
$\%CH_{4_{i\ or\ j,t}}$	Concentration of CH_4 in the gas stream **i** or **j** that is being flared in Reporting Period **t**.	$\%CH_4$ by volume, expressed as a decimal	M	Continuous or monthly	Measured at the input to the flare system.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
$\mathbf{Count_{s,t}}$	Total number of each type of emission source **s** (e.g., wells, equipment) in the transport segment in Reporting Period **t**.	#	O, C	Once per Reporting Period	Operator shall develop and maintain an equipment inventory to identify all possible fugitive emission sources from surface facilities and equipment in this segment. If the number of emission sources varies during the Reporting Period, this number shall include all emission sources (i.e., the maximum number) that were present during that Reporting Period.
$T_{s,t}$	Total time that the equipment associated with emission source **s** in the transport segment that was operational in Reporting Period **t**.	hours	M, O, C	Monthly or once per Reporting Period	Measured or estimated based on operational records and downtime of the equipment in this segment. Where equipment hours are unknown, this value shall equal the number of hours in the Reporting Period.
$\mathbf{\%GHG_{j,s,t}}$	Concentration of GHG **j** (CO_2 and CH_4) in equipment **s** in the transport segment in Reporting Period **t**.	%GHG by volume, expressed as a decimal	M	Continuous or monthly	Direct measurement of the composition of the gas stream.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
$Electricity_{i,p,t}$	Metered offsite electricity **i** used to operate all equipment associated with CO_2 pipeline **p** in Reporting Period **t**.	e.g., MWh, kWh	M, O	Continuous or monthly	Continuous measurement of electricity consumption or monthly billing records from utility supplier, or see **$Electrical\ Rating_{i,t}$**, **$Hours_{i,t}$**, and **$Load_{i,t}$** in the “Alternative Quantification Methods” subsection of Table 7 (below) for an alternative way to calculate electricity using reconciliation of maximum kW rating for each type of equipment and operating hours.
$Distance\ Pipeline_{q,t}$	Distance traveled by CO_2 pipeline **q** used by multiple parties in Reporting Period **t**.	e.g., miles, km	M, O, C	Once per Crediting Period	Distance shall be measured along the CO_2 flow path from the point of capture to the point of injection. All required geospatial and engineering documentation shall be consolidated and reported for the primary pathway only.
$Mass\ Product_{prod,r,t}$	Mass of product **prod** transported via mobile transport mode **r** in Reporting Period **t**.	MT	M	Continuous	This includes the mass or weight of the container (e.g., CO_2 tank) plus the mass or weight of the contained

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
					product/material, by mobile mode of transport **r** (e.g., barge, truck).
$\text{Distance}_{prod,r,t}$	Distance that product **prod** traveled via mobile transport mode **r** in Reporting Period **t**.	miles	M, O, C	Continuous	Distance of travel shall be logged and tracked per shipment, from point of origin to the point of use within the CCS project, or for distances within the CCS project boundary. Logs shall be consolidated by product type and transport mode. See Section E.2.2.
$\text{Vol.}_{\text{Gas Transferred}_{c\&x,t}}$	Total volume of gas captured from CO_2 sources **c** and **x** located upstream of the first transfer to transport and input into the first mode of transport, in Reporting Period **t**.	m^3	M	Continuous	Measured at (or corrected to) standard conditions at the point of transfer to the first mode of transport.
$\%CO_{2\,\text{Gas Transferred}_{c\&x,t}}$	Concentration of CO_2 in the gas stream from CO_2 sources **c** and **x** located upstream of the first transfer to transport in Reporting Period **t**.	$\%CO_2$ by volume, expressed as a decimal	M	Continuous or monthly	Measured at a point relative to $\text{Vol.}_{\text{Gas Transferred}_{c\&x,t}}$ that allows for accurate measurement.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
$Vol._{Gas\ Transferred\ to\ Storage_{p,r,t}}$	Volume of gas that has been transferred to the injection and storage site operator by single-user CO_2 pipeline **p** and mobile transport mode **r** in Reporting Period **t**.	m^3	M	Continuous	Measured at the point(s) of transfer to the injection and storage site at (or corrected to) standard conditions.
$\%CO_{2_t}$	Concentration of CO_2 in the gas stream in the transport segment in Reporting Period **t**.	$\%CO_2$ by volume, expressed as a decimal	M	Continuous	Measured at the point(s) of transfer to the injection and storage site at a location relative to $Vol._{Gas\ Transferred\ to\ Storage_{p,r,t}}$ that allows for accurate measurement
$N_{Blowdown_{i,t}}$	Number of blowdowns for equipment **i** in Reporting Period **t**, obtained from blowdown event logs.	#	O, C	As occurs	Operators shall keep detailed logs of all venting incidents.
$V_{Blowdown_{i,t}}$	Total volume of blowdown equipment chambers for equipment **i** (including pipelines, manifolds, and vessels between isolation valves) associated with the	m^3	O, C	Once per Reporting Period	Volume can be estimated based on equipment specifications (e.g., pipeline diameters), flow meters, and duration of event. Refer to Appendix C.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
	transport segment, in Reporting Period **t**.				
$\%GHG_{j,t}$	Concentration of GHG **j** (CO_2 and CH_4) in the vented substance in Reporting Period **t**.	%GHG by volume, expressed as a decimal	M	Continuous or as occurs	Direct measurement of the composition of the gas stream at the venting location.
INJECTION, STORAGE, MONITORING & HYDROCARBON PRODUCTION AND ONSITE PROCESSING SEGMENT					
$Fuel_{i,g,t}$	Volume or mass of fuel type **i** used to inspect, maintain, and operate the CO_2 injection and storage infrastructure and hydrocarbon production and onsite processing facilities (if applicable) at geologic storage reservoir **g** in Reporting Period **t**.	e.g., m^3, kg	M, O, C	Daily or monthly	For gaseous fuels, daily measurement of the gas flow rate. For liquid and solid fuels, monthly reconciliation of purchasing records with inventory adjustments as needed are acceptable. For liquid and solid fuels, volume or mass measurements are commonly made upon purchase or delivery of the fuel. Reconciliation of purchase receipts or weigh scale tickets are an acceptable means to determine the quantities of fuels consumed.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
$Gas\ Flared_{i,t}$	Volume of gas flared, by gas type **i**, in Reporting Period **t**.	m^3	M	Continuous	Gas volume shall be measured at the flare. Gas volume shall be measured at (or corrected to) standard conditions.
$Flare\ Fuel_{j,t}$	Volume of each supplemental fuel, by fuel type **j** used to ensure complete combustion of the gases, in Reporting Period **t**.	m^3	M, O, C	Daily or monthly	For gaseous fuels, daily measurement of the gas flow rate. For liquid and solid fuels, monthly reconciliation of purchasing records and inventory adjustments are acceptable. For liquid and solid fuels, volume or mass measurements are commonly made upon purchase or delivery of the fuel. Reconciliation of purchase receipts or weigh scale tickets are an acceptable means to determine the quantities of fuels consumed.
$y_{i,t}$	Direct measurement of the mole fractions of each carbon-containing gas in gas mixture **i** in Reporting Period **t**.	decimal fraction	M	Continuous or monthly	Measured using gas chromatograph.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
$\%CH4_{i\ or\ j,t}$	Concentration of CH_4 in gas stream **i** or **j** that is being flared in Reporting Period **t**.	$\%CH_4$ by volume, expressed as a decimal	M	Continuous or monthly	Measured at the input to the flare system.
$Electricity_{e,t}$	Metered offsite electricity source **e** used to operate equipment associated with the injection, storage, monitoring& hydrocarbon production and onsite processing segment in Reporting Period **t**.	e.g., MWh, kWh	M, O, C	Continuous or monthly	Continuous measurement of electricity consumption or monthly billing records from utility supplier, or see $Electrical\ Rating_{i,t}$, $Hours_{i,t}$, and $Load_{i,t}$ in the "Alternative Quantification Methods" subsection of Table 7 (below) for an alternative way to calculate electricity using reconciliation of maximum kW rating for each type of equipment and operating hours. .
$Thermal\ Energy_{h,t}$	Offsite thermal energy **h** used to operate equipment associated with the injection, storage, monitoring & hydrocarbon production and	MMBtu	M, O, C	Daily or monthly	Measured daily using a utility meter or measured monthly via invoices from the thermal energy provider showing the quantity of thermal energy supplied.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
	onsite processing segment in Reporting Period **t**.				
$N_{Blowdown_{i,t}}$	Number of blowdowns for equipment **i** in Reporting Period **t**, obtained from blowdown event logs.	#	O, C	As occurs	Operators shall keep detailed logs of all venting incidents.
$V_{Blowdown_{i,t}}$	Total volume of blowdown equipment chambers for equipment **i** (including pipelines, manifolds, and vessels between isolation valves) associated with the injection, storage, monitoring & hydrocarbon production and onsite processing segment in Reporting Period **t**.	m^3	O, C	Once per Reporting Period	Volume can be estimated based on equipment specifications (e.g., pipeline diameters), flow meters, and duration of event. Refer to Appendix C.
$\%GHG_{j,t}$	Concentration of GHG **j** (CO_2 and CH_4) in the vented substance in Reporting Period **t**.	%GHG by volume, expressed as a decimal	M	Continuous or as occurs	Direct measurement of the composition of the gas stream at the venting location.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
$Count_{s,t}$	Total number of each type of emission source **s** (e.g., wells, equipment) in the injection, storage, monitoring & hydrocarbon production and onsite processing segment in Reporting Period **t**.	#	O, C	Once per Reporting Period	Operator shall develop and maintain an equipment inventory to identify all possible fugitive emission sources from surface facilities and equipment in this segment. If the number of emission sources varies during the Reporting Period, this number shall include all emission sources (i.e., the maximum number) that were present during that Reporting Period.
$T_{s,t}$	Total time that the equipment associated with emission source **s** in the injection, storage, monitoring & hydrocarbon production and onsite processing segment was operational in Reporting Period **t**.	hours	M, O, C	Monthly or once per Reporting Period	Measured or estimated based on operational records and downtime of the equipment in this segment. Where equipment hours are unknown, this value shall equal the number of hours in the Reporting Period.
$\%GHG_{j,s,t}$	Concentration of GHG **j** (CO_2 and CH_4) in equipment **s** in the injection, storage, monitoring, & hydrocarbon production and onsite	%GHG by volume, expressed	M	Continuous or monthly	Direct measurement of the composition of the gas stream.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
	processing segment in Reporting Period **t**.	as a decimal			
CO_2-EOR OPERATIONS (SUBSET OF INJECTION, STORAGE, MONITORING & HYDROCARBON PRODUCTION AND ONSITE PROCESSING SEGMENT)					
$Vol._{Hydrocarbon\ Gas_{g,t}}$	Volume of hydrocarbon gas, produced from geologic storage reservoir **g** that is sold or otherwise transported outside the project boundary in Reporting Period **t**.	e.g., m^3, scf	M	Continuous	Measured at (or corrected to) standard conditions at a point downstream of the where the gas is produced but still onsite. This excludes CO_2 transported outside of the project boundary that is accounted for under other equations (e.g., Equation 20).
$\%CO_{2\ Hydrocarbon\ Gas_{g,t}}$	Concentration of CO_2 in hydrocarbon gas produced from geologic storage reservoir **g** that is sold or otherwise transported outside the project boundary in Reporting Period **t**.	% CO_2 by volume, expressed as a decimal	M	Continuous or monthly	Measured at a point relative to $Vol._{Hydrocarbon\ Gas_{g,t}}$ that allows for accurate measurement.
$Mass_{Water\ Prod_{g,t}}$	Mass of water produced from geologic storage reservoir **g** that contains entrained CO_2 that is sold to, otherwise	MT	M, O	Continuous or monthly	Monthly reconciliation of water disposal records. If CO_2 concentrations are lower when water is re-injected than when it is

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
	transported outside the project boundary, or otherwise not re-injected back into the formation, in Reporting Period **t**.				extracted from the formation, the CO_2 must be measured and reported. If operators are using a closed loop water handling system, proponents may assume that CO_2 is being captured and therefore not an emission.
$\mathbf{Mass\ Frac_{CO_2\ in\ Water_{g,t}}}$	Mass fraction of CO_2 in the water produced from geologic storage reservoir **g** in Reporting Period **t**.	decimal fraction	M, O	Once per Reporting Period	Lab analysis of the composition of produced water including quantification of dissolved inorganic carbon species.
$\mathbf{Mass_{Oil\ Prod_{g,t}}}$	Mass of crude oil and other liquid hydrocarbons produced from geologic storage reservoir **g** in Reporting Period **t**.	MT	M, O	Continuous or monthly	Mass shall be measured at the point of transfer offsite or through reconciliation of crude oil sales from facilities associated with the producing formation.
$\mathbf{Mass\ Frac_{CO_2\ in\ Oil\ Prod_{g,t}}}$	Mass fraction of CO_2 in the crude oil and other liquid hydrocarbons produced from geologic storage reservoir **g** in Reporting Period **t**.	decimal fraction	M, O	Once per Reporting Period	Lab analysis of the composition of crude oil and other liquid hydrocarbons.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
$\text{Mass Frac}_{\text{Vented } CH_4 \text{ in Water Prod}_{g,t}}$	Mass fraction of CH_4 in the water produced from geologic storage reservoir **g**, from which the gases are vented to the atmosphere, in Reporting Period **t**.	decimal fraction	M, O	Once per Reporting Period	Lab analysis of the composition of produced water including quantification of methane.
$\text{Mass Frac}_{\text{Vented } CH_4 \text{ in Oil Prod}_{g,t}}$	Mass fraction of CH_4 in the crude oil and other liquid hydrocarbons produced from geologic storage reservoir **g**, from which the gases are vented to the atmosphere, in Reporting Period **t**.	decimal fraction	M, O	Once per Reporting Period	Lab analysis of the composition of crude oil and other liquid hydrocarbons including quantification of methane.
$\text{Mass}_{\text{Injected}_{w,g,t}}$	Mass of CO_2 injected into injection well **w** in geologic storage reservoir **g** in Reporting Period **t**.	MT	M	Continuous	Measured at the surface point of injection into the storage reservoir.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
CONSTRUCTION AND POST-INJECTION PERIOD MONITORING, DECOMMISSIONING & CLOSURE SEGMENTS					
$\textbf{Mass Product}_{prod,r,t}$	Mass of construction materials and equipment **prod** transported via mobile transport mode **r** in Reporting Period **t**, before the start of the Crediting Period, or anticipated in the post-injection period, as applicable.	MT	M	Continuous	This includes the mass or weight of the container (e.g., CO_2 tank) plus the mass or weight of the contained product/material. Conservative engineering estimates for post-injection period products are acceptable.
$\textbf{Distance}_{prod,r,t}$	Distance that construction materials and equipment **prod** traveled via mobile transport mode **r** in Reporting Period **t**, before the start of the Crediting Period, or anticipated in the post-injection period, as applicable.	miles	M, O, C	Continuous	Distance of travel shall be logged and tracked per shipment, from point of origin to the point of use within the CCS project, or for distances within the CCS project boundary. Logs shall be consolidated by product type and transport mode. See Section E.2.2. Conservative engineering estimates for post-injection period distances traveled are acceptable.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
$Fuel_{i,eq,t}$	Volume or mass of fuel type **i** used to operate construction equipment **eq** in Reporting Period **t**, before the start of the Crediting Period, or anticipated in the post-injection period, as applicable.	e.g., m^3, kg	M, O, C	Daily or monthly	For gaseous fuels, daily measurement of the gas flow rate. For liquid and solid fuels, monthly reconciliation of purchasing records with inventory adjustments as needed are acceptable. For liquid and solid fuels, volume or mass measurements are commonly made upon purchase or delivery of the fuel. Reconciliation of purchase receipts or weigh scale tickets are an acceptable means to determine the quantities of fuels consumed. Conservative engineering estimates for post-injection period fuel use are acceptable.
$\textbf{Gas Flared}_{i,t}$	Volume of gas flared during construction and post-injection operations, by gas type **i**, in Reporting Period **t**, before the start of the Crediting Period, or anticipated in the post-	m^3	M	Continuous	Gas volume shall be measured at the flare. Gas volume shall be measured at (or corrected to) standard conditions. Conservative engineering estimates for post-injection period flaring are acceptable.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
	injection period, as applicable.				
$Flare\ Fuel_{j,t}$	Volume of each supplemental fuel, by fuel type **j** used to ensure complete combustion of the gases during construction and post-injection operations, in Reporting Period **t**, before the start of the Crediting Period, or anticipated in the post-injection period, as applicable.	m^3	M, O, C	Daily or monthly	For gaseous fuels, daily measurement of the gas flow rate. For liquid and solid fuels, monthly reconciliation of purchasing records and inventory adjustments are acceptable. For liquid and solid fuels, volume or mass measurements are commonly made upon purchase or delivery of the fuel. Reconciliation of purchase receipts or weigh scale tickets are an acceptable means to determine the quantities of fuels consumed. Conservative engineering estimates for post-injection period flare fuels are acceptable.
$y_{i,t}$	Direct measurement of the mole fractions of each carbon-containing gas in gas mixture **i** during construction and post-injection operations, in Reporting	decimal fraction	M	Continuous or monthly	Measured using gas chromatograph. Conservative engineering estimates for post-injection period mole fractions are acceptable.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
	Period **t**, before the start of the Crediting Period, or anticipated in the post-injection period, as applicable.				
$\%CH_{4_t}$	Concentration of CH_4 in the gas stream that is being flared during construction and post-injection operations in Reporting Period **t**, before the start of the Crediting Period, or anticipated in the post-injection period, as applicable.	$\%CH_4$ by volume, expressed as a decimal	M	Continuous or monthly	Measured at the input to the flare system. Conservative engineering estimates for post-injection period methane concentrations are acceptable.
$Electricity_{e,t}$	Metered offsite electricity source **e** used during construction and post-injection operations equipment in Reporting Period **t**, before the start of the Crediting Period, or anticipated in the post-injection period, as applicable.	e.g., MWh, kWh	M, O	Continuous or monthly	Continuous measurement of electricity consumption or monthly billing records from utility supplier, or see $Electrical\ Rating_{i,t}$, $Hours_{i,t}$, and $Load_{i,t}$ in the “Alternative Quantification Methods” subsection of Table 7 (below) for an alternative way to calculate electricity using reconciliation of maximum kW rating

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
					for each type of equipment and operating hours. Conservative engineering estimates for post-injection period electricity use are acceptable.
$\text{Thermal Energy}_{h,t}$	Offsite thermal energy **h** used to operate construction and post-injection operations equipment in Reporting Period **t**, before the start of the Crediting Period, or anticipated in the post-injection period, as applicable.	MMBtu	M, O	Daily or monthly	Measured daily using a utility meter or measured monthly via invoices from the thermal energy provider showing the quantity of thermal energy supplied. Conservative engineering estimates for post-injection period thermal energy use are acceptable.
Mass_{m_t}	Mass or weight of produced material **m** brought into use at the CCS project in Reporting Period **t**, before the start of the Crediting Period, or anticipated in the post-injection period, as applicable.	e.g., kg, g, lb	M	Once per Crediting Period for pre-Crediting Period emissions, once per Reporting Period for material brought into use during a Reporting Period	Measure the total mass of each of the produced materials used in the construction of the CCS project facilities (see the materials listed in Table 6 and steel as specified in Table 19). Conservative engineering estimates for post-injection period produced materials masses are acceptable.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
$Mass_{Pipeline,t}$	Mass or weight of the steel material utilized for pipeline and pipeline compressors **Pipeline** brought into use at the CCS project in Reporting Period **t** or before the start of the Crediting Period, as applicable.	e.g., kg, g, lb	M	Once per Crediting Period	Measure the total mass of each of the steel material utilized for pipeline and pipeline compressors of the CCS project from the start of construction to the project in-service date (see the steel materials listed in Table 19).
PRODUCED OIL & ASSOCIATED GAS EMISSIONS (CO_2-EOR ONLY)					
$Vol.\ Crude\ U.S._{g,t}$	Volume of crude oil produced from U.S. geologic storage reservoir **g** in Reporting Period **t**.	bbl	M	Continuous	Measured immediately before custody transfer to another entity and before shipment offsite of the CO_2 storage location.
$Assoc.\ Gas\ U.S._{g,t}$	Volume of associated gas produced from U.S. geologic storage reservoir **g** in Reporting Period **t**.	scf	M	Continuous	Measured immediately before custody transfer to another entity and before shipment offsite of the CO_2 storage location.
$Assoc.\ Gas\ Canada_{g,t}$	Volume of associated gas produced from Canadian geologic storage reservoir **g** in Reporting Period **t**.	scf	M	Continuous	Measured immediately before custody transfer to another entity and before shipment offsite of the CO_2 storage location.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
$Vol.\ Crude\ Canada_{g,t}$	Volume of crude oil produced from Canadian geologic storage reservoir **g** in Reporting Period **t**.	bbl	M	Continuous	Measured immediately before custody transfer to another entity and before shipment offsite of the CO_2 storage location.
$\rho Crude_{g,t}$	Density of crude oil produced from geologic storage reservoir **g** in Reporting Period **t**.	kg/m^3	M	Monthly	Measured at (or corrected to) standard conditions at the site of production.
GEOLOGIC STORAGE RESERVOIR SEGMENT					
$CO2_{z,g,t}$	Total mass of CO_2 emitted through pathway **z** in geologic storage reservoir **g** in Reporting Period **t**.	$MTCO_2$	O, C	As occurs	If emissions from the geologic reservoir to the atmosphere occur, the mass of CO_2 that has escaped is calculated based on monitoring and measurements completed as part of the MRV Plan. This does not include fugitive CO_2 emissions from produced water and oil, which are calculated according to Equation 23.
$CO2_{z,g,post}$	Total mass of CO_2 emitted through pathway **z** in geologic storage reservoir **g**	$MTCO_2$	O, C	As occurs	If emissions from the geologic reservoir to the atmosphere occur post-injection, the mass of CO_2 that has escaped is calculated based on

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
	during the post-injection period **post**.				monitoring and measurements completed as part of the MRV Plan. This does not include fugitive CO_2 emissions from produced water and oil, which are calculated according to Equation 23.
ALTERNATIVE QUANTIFICATION METHODS (SEE APPENDIX C)					
$\mathbf{Q_{f,t}}$	Mass flow through meter **f** in Reporting Period **t**.	MT	M	Continuous	Measured at the same point noted in the volume parameter above for which mass is replacing volume.
$C_{CO_{2f,t}}$	CO_2 concentration measurement in flow meter **f** in Reporting Period **t**.	% CO_2 by weight, expressed as decimal	M	Continuous	Measured at the same point as $\mathbf{Q_{f,t}}$.
$\mathbf{Electrical\ Rating_{i,t}}$	Electrical rating for equipment **i** used in the relevant project segment (e.g., capture, processing & compression; transport; injection, storage, monitoring & hydrocarbon production	MW	O, C	Once per Reporting Period	Electrical rating for equipment based on manufacturer-provided equipment specifications.

PARAMETER	DESCRIPTION	UNITS	TYPE[63]	MEASUREMENT FREQUENCY	REQUIREMENTS
	and onsite processing) in Reporting Period **t**.				
$\mathbf{Hours_{i,t}}$	Operating hours for each piece of equipment **i** that uses electricity in Reporting Period **t**.	hours	O, C	Continuous or monthly	Measured (with associated records) or, if insufficient records are available, assumed to be equal to the number of hours in the Reporting Period for conservativeness.
$\mathbf{Load_{i,t}}$	Percent loading of each piece of equipment **i** that uses electricity in Reporting Period **t**.	unitless	O, C	Continuous or monthly	Estimated (with estimate reasoning documented) or assumed to be 100%.

7.2 Measurement Requirements

Mass flow and volumetric flow rates will be quantified by commercially available devices that measure mass or flow of a gas or liquid moving through an open or closed conduit. Flow meters include, but are not limited to, rotameters, turbine meters, coriolis meters, orifice meters, ultra-sonic flow meters, and vortex flow meters. Flow meters will be operated in accordance with an appropriate standard method published by a consensus-based standards organization (if such a method exists) or an industry standard practice. The specific standard used shall be documented and reported in the GHG Project Plan and MRV Plan. Consensus-based standards organizations include, but are not limited to, ASTM International, the American National Standards Institute, the American Gas Association, the American Society of Mechanical Engineers, the American Petroleum Institute (API), and the North American Energy Standards Board. Flow meter calibrations performed shall be National Institute of Standards and Technology traceable. This methodology incorporates some of the requirements contained in U.S. EPA's GHG Reporting Regulation Subpart RR (specifically, 40 CFR 98.444; U.S. EPA, 2010d) for where to locate measurement equipment, and incorporates the calibration requirements contained in Subpart A of the same regulation (specifically, 40 CFR 98.3(i); U.S. EPA, 2025b).

All measurement devices, including but not limited to flow meters, gas analyzers, electricity meters, and thermal energy meters must be inspected, maintained, checked and calibrated according to the following:

I. All instruments must be:
    A. Inspected and maintained on a quarterly basis, with the activities performed and "as found/as left condition" of the equipment documented;
    B. Field-checked per manufacturer specifications by a trained professional for calibration accuracy (the Project Proponent may conduct this check) with the percent drift documented; and,
    C. Calibrated by the manufacturer or a certified calibration service per manufacturer's specifications or an appropriate industry consensus standard at the frequency recommended by the manufacturer or annually, whichever is more frequent.
II. A field check must be performed before any corrective action (e.g., instrument calibration or repositioning) is applied.
III. If a field check on a piece of equipment reveals accuracy beyond a +/- 5% threshold, all data from that piece of equipment must be either excluded (if part of baseline emissions) or scaled according to the following procedure. These adjustments must be made for the entire period from the last successful check until such time as corrective action is taken and a subsequent check demonstrates the equipment to again be within the +/-5% accuracy threshold.

A. For each check that indicates the piece of equipment was beyond the +/- 5% accuracy threshold, the project developer shall calculate total emission reductions using:
    i. The monitored values without correction; and
    ii. The monitored values adjusted based on the calibration drift recorded at the time of the check.
B. The higher of the two project emissions values shall be reported as the scaled value.

Calibration records shall be maintained and made available to ACR and the VVB.

Gas flow volumes shall be measured at (or corrected to) standard temperature and pressure as defined by this Methodology. Data on gas and liquid stream composition analysis shall include calibrations of the gas analyzer or other instrumentation used. If an outside third-party laboratory is used, documentation of their accreditation to conduct the analysis shall be obtained.

Fuel billing meters are exempted from calibration requirements provided that the fuel supplier and any unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company (U.S. EPA 40 CFR Subpart A, 98.3(i)) (U.S. EPA, 2025b).

Data substitution is allowed for limited circumstances such as where a project encounters flow rate or CO_2 concentration data gaps. Project Proponents may apply the data substitution methodology provided in Appendix F.

7.3 Monitoring, Reporting, and Verification (MRV) Plan

The purpose of the CCS project MRV Plan is to ensure that projects are rigorously monitored to confirm the safe, permanent storage of CO_2, and to detect any migration of CO_2 outside the geologic storage reservoir. The MRV Plan shall involve systematic monitoring and accountability for CO_2 injection, storage, and any unintended emissions, and must be tailored to site-specific geologic conditions and operational considerations. This Methodology's requirements for MRV Plans methodology are aligned with U.S. (U.S. EPA, 2010a; U.S. EPA, 2010d), Canada (CSA, 2012/2022), and international (ISO, 2017) standards.

Each CCS project must submit a project-specific MRV Plan that is developed by a professional (or professionals) with demonstrated experience and knowledge of design and implementation of systems for monitoring geologic storage of CO_2, along with expertise in an earth science discipline relevant to the CCS project (e.g., reservoir engineering, geophysics, geology, hydrology, geomechanics, geochemistry) and experience and expertise in underground monitoring techniques.

Demonstrated experience and knowledge shall be evidenced by at least three years' experience in monitoring CO_2 storage projects, and/or by published, relevant peer-reviewed academic research on monitoring of CO_2 storage. The curriculum vitae of this professional will be reviewed by ACR and the VVB to confirm that they meet the above requirements.

MRV Plans shall be developed to meet or exceed specific requirements outlined in ICAO (2025) Table 3 and U.S. EPA Class VI requirements as outlined in this section, regardless of the permitting classification or jurisdiction. While jurisdictional requirements may vary, adherence to the standards outlined below ensures consistency, robustness, and a high level of environmental integrity across all CCS projects. Aligning with these standards supports accurate quantification of greenhouse gas reductions and provides confidence in the long-term containment of injected CO_2.

The Project Proponent shall continually update the MRV Plan and the revisions shall be subject to review by the VVB at each verification interval or next validation (in the case of Crediting Period renewal), whichever comes first. If jurisdictional approval of the MRV Plan is required, approval must be attained prior to injection operations.

7.3.1 MRV PLAN VALIDATION AND VERIFICATION REQUIREMENTS

Validation of the MRV Plan shall be conducted by a competent, ACR-approved VVB. As part of this process, the VVB shall confirm, in accordance with ACR CCS Methodology and *ACR Standard* requirements, whether the MRV Plan has been formally reviewed and approved by a competent jurisdictional authority with regulatory oversight of CO_2 injection and storage. This confirmation shall include reviewing relevant plans, permits, and regulatory correspondence to confirm compliance.

If no such jurisdictional approval exists, the MRV Plan must be reviewed, approved, and signed off by a qualified professional at the time of initial validation. This professional may be subcontracted by the VVB or be an employee of the VVB. This individual must have demonstrated expertise in geologic CO_2 storage monitoring and relevant credentials in an earth science discipline such as reservoir engineering, geophysics, geology, hydrology, geomechanics, or geochemistry.

Subsequent verifications must also be reviewed by this professional, or one with equivalent qualifications, to confirm continued adherence to the MRV Plan during each Reporting Period in which credits are claimed. Additionally, any subsequent validations (e.g., at Crediting Period renewal) must include review of updates or modifications to the MRV Plan by a similarly qualified professional.

The VVB shall document the initial MRV validation, as well as all subsequent reviews and verifications, in validation and verification opinions.

7.3.2 REQUIRED SITE-SPECIFIC AND PLAN INFORMATION

The following requirements follow U.S. EPA UIC Regulation § 146.82 (Required Class VI permit information; U.S. EPA, 2010c). MRV Plans shall include the following site-specific information:

I. A map showing the injection well(s) and the applicable area of review consistent with Section 7.3.5. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, provincial or state, Tribal, and Territory boundaries, and roads. The map should also show faults, if known or suspected. Only information of public record is required to be included on this map;
II. Information on the geologic structure and hydrogeologic properties of the proposed geologic storage reservoir and overlying formations, including:
    A. Maps and cross sections of the area of review;
    B. The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment;
    C. Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;
    D. Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);
    E. Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and
    F. Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.
III. A tabulation of all wells within the area of review which penetrate the injection or confining zone(s). Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the jurisdiction may require;
IV. Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known;

V. Baseline geochemical data on subsurface formations, including all USDWs in the area of review;

VI. Proposed operating data for the proposed geologic storage reservoir:

   A. Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;

   B. Average and maximum injection pressure;

   C. The source(s) of the CO_2 stream; and

   D. An analysis of the chemical and physical characteristics of the CO_2 stream.

VII. Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) and that meets the requirements at Section 7.3.7;

VIII. Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;

IX. Procedure to outline steps necessary to conduct injection operation;

X. Schematics or other appropriate drawings of the surface and subsurface construction details of the well;

XI. Injection well construction procedures required by Section 7.3.6;

XII. Area of Review and Corrective Action Plan as required by Section 7.3.5;

XIII. Testing and Monitoring Plan required by Section 7.3.7;

XIV. Well-Plugging Plan required by Section 7.3.11;

XV. Post-Injection Site Care and Closure Plan required by Section 7.3.12;

XVI. Emergency and Remedial Response Plan required by Section 7.3.13; and

XVII. A plan for quantifying any emission of CO_2 from the storage volume as outlined in Section 6.2.7.

7.3.3 INJECTION ZONE REQUIREMENTS

The injection zone shall meet all of the following conditions:

I. Be located within the Earth's crust and may be situated either onshore or offshore.

II. Be isolated from USDWs by a sufficient thickness of sufficiently impermeable strata. This isolation barrier is generally considered adequate when there is an accumulative total of at least 250 feet of clay, shale, or other confining materials with low permeability characteristics between the injection zone and any USDW, defined as aquifers containing water with total dissolved solids of 10,000 mg/L or less and not exempted under applicable regulations.

III. Be located at a minimum depth of 800 meters (2,600 feet) below ground surface to ensure that natural temperature and pressure conditions maintain CO_2 in a supercritical state. This depth may vary depending on the pressure of overlying strata.

7.3.4 GEOLOGIC STORAGE RESERVOIR SITING CRITERIA

The following requirements follow U.S. EPA UIC Regulation § 146.83 (Minimum criteria for siting; U.S. EPA, 2010c). Project Proponents must demonstrate in the MRV Plan that the geologic storage reservoir's system comprises:

I. An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the CO_2 stream;
II. Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected CO_2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).
III. Are free of faults and fractures that may interfere with containment.

7.3.5 AREA OF REVIEW AND CORRECTIVE ACTION PLAN

The following requirements follow U.S. EPA UIC Regulation § 146.84 (Area of review and corrective action; U.S. EPA, 2010c). The area of review is the region surrounding the CCS project where USDWs may be endangered by the injection activity and where conduits for emission of CO_2 from the geologic storage reservoir to the surface may exist. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected CO_2 stream and is based on available site characterization, monitoring, and operational data. The Project Proponent must prepare, maintain, and comply with a plan to delineate the area of review for a proposed CCS project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the jurisdictional authority.

As part of the MRV Plan, the Project Proponent must submit an Area of Review and Corrective Action Plan that includes the following information:

I. The method for delineating the area of review that meets the requirements of this section, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based; and

II. A description of the following:
   A. The minimum fixed frequency, not to exceed five years, at which the Project Proponent proposes to reevaluate the area of review;
   B. The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation as determined by this minimum fixed frequency;
   C. How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and
   D. How corrective action will be conducted, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.

Project Proponents must perform the following actions to delineate the area of review and identify all wells that require corrective action:

III. Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the CO_2 plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids outside of the geologic storage reservoir are no longer present, or until the end of a fixed time period as determined by the jurisdictional authority. The MRV Plan must describe any flow simulation model and assess uncertainty by documenting key parameters, failure scenarios, and results from sensitivity analyses to support risk-based monitoring and define the limits of storage integrity throughout the Minimum Project Term. Modeling must:
   A. Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the CCS project;
   B. Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and
   C. Consider potential migration through faults, fractures, and artificial penetrations.
   D. Identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the jurisdictional authority may require; and

E. Determine which abandoned wells in the area of review have been plugged in a manner that prevents the movement of CO_2 or other fluids outside the geologic storage reservoir, including use of materials compatible with the CO_2 stream.

Project Proponents must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the CO_2 stream, where appropriate. Correction action may require monitoring or remediation (e.g., re-plugging, casing repair). Documentation of corrective actions must demonstrate mitigation of CO_2 migration pathways to the surface (i.e., atmosphere).

At the minimum fixed frequency, not to exceed five years, as specified in the Area of Review and Corrective Action Plan, or when monitoring and operational conditions warrant, Project Proponents must:

IV. Reevaluate the area of review in the same manner specified in Section 7.3.5.I.;
V. Identify all wells in the reevaluated area of review that require corrective action.;
VI. Perform corrective action on wells requiring corrective action in the reevaluated area of review; and
VII. Submit an amended Area of Review and Corrective Action Plan or demonstrate to the jurisdictional authority through monitoring data and modeling results that no amendment to the Area of Review and Corrective Action Plan is needed. Any amendments to the Area of Review and Corrective Action Plan must be approved by the jurisdictional authority.

All modeling inputs and data used to support area of review reevaluations section shall be retained by the Project Proponent for 10 years.

7.3.6 INJECTION WELL CONSTRUCTION REQUIREMENTS

All CO_2 injection wells in the U.S. and Canada must meet or exceed the well design requirements outlined below as well as any additional applicable jurisdictional requirements that affect the design, construction, completion, operation, plugging, and testing of wells. The following requirements follow U.S. EPA UIC Regulation § 146.86 (Injection well construction requirements; U.S. EPA, 2010c). All wells must be constructed and completed to prevent the movement of fluids into or between USDWs or into any unauthorized zones, permit the use of appropriate testing devices and workover tools, and permit continuous monitoring of the annulus space between the injection tubing and long string casing. (146.86(a)).

7.3.6.1 Casing and Cementing of Injection Wells

Casing and cement or other materials used in the construction of each injection well must have sufficient structural strength and be designed to maintain integrity for the full life of the geologic sequestration project, including well construction, operation and CO_2 injection, monitoring and testing, and operation, and extends through the post-injection site care period, which is at least 50 years (U.S. EPA, 2010c). All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by API, ASTM International, or comparable standards acceptable to the jurisdictional authority. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs.

The Project Proponent shall provide the following information in the MRV Plan:

I. Depth to the injection zone(s);
II. Injection pressure, external pressure, internal pressure, and axial loading;
III. Hole size;
IV. Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);
V. Corrosiveness of the injection stream and formation fluids;
VI. Down-hole temperatures;
VII. Lithology of injection and confining zone(s);
VIII. Type or grade of cement and cement additives; and
IX. Quantity, chemical composition, and temperature of the injection stream.

Surface casing must extend through the base of the lowermost USDW and be cemented to the surface using a single or multiple strings of casing and cement. At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages. Circulation of cement may be accomplished by staging. The jurisdictional authority may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the site operator[67] can demonstrate by using logs that the cement does not allow fluid movement behind the well bore. Cement and cement additives must be compatible with the CO_2 stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the CCS project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.

[67] "Site operator" means the same thing as "injection and storage site operator."

7.3.6.2 Tubing and Packer

Tubing and packer materials used in the construction of each injection well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by API or ASTM International. All site operators must inject fluids through tubing with a packer set at a depth opposite a cemented interval.

The Project Proponent shall provide the following information in the MRV Plan:

I. Depth of setting;
II. Characteristics of the CO_2 stream (chemical content, corrosiveness, temperature, and density) and formation fluids;
III. Maximum proposed injection pressure;
IV. Maximum proposed annular pressure;
V. Proposed injection rate (intermittent or continuous) and volume and/or mass of the CO_2 stream;
VI. Size of tubing and casing; and
VII. Tubing tensile, burst, and collapse strengths.

7.3.7 LOGGING, SAMPLING & TESTING PRIOR TO INJECTION WELL OPERATION

The following requirements follow U.S. EPA UIC Regulation § 146.87 (Logging, sampling, and testing prior to injection well operation; U.S. EPA, 2010c). During the drilling and construction of a new injection well, the site operator must run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements in Section 7.3.6 and to establish accurate baseline data against which future measurements may be compared.

The Project Proponent shall provide, as part of the MRV Plan, a Testing and Monitoring Plan prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests for all newly drilled and constructed wells. This plan must include the following:

I. Deviation checks during drilling on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling; and
II. Before and upon installation of the surface casing:

   A. Resistivity, spontaneous potential, and caliper logs before the casing is installed; and
   B. A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.

III. Before and upon installation of the long string casing:
   A. Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the jurisdictional authority requires for the given geology before the casing is installed; and
   B. A cement bond and variable density log, and a temperature log after the casing is set and cemented.

IV. A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include one or more:
   A. A pressure test with liquid or gas,
   B. A tracer survey such as oxygen-activation logging,
   C. A temperature or noise log,
   D. A casing inspection log, and

V. Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the jurisdictional authority.

The site operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).

At a minimum, the site operator must determine or calculate the following information concerning the injection and confining zone(s):

VI. Fracture pressure,
VII. Other physical and chemical characteristics of the injection and confining zone(s), and
VIII. Physical and chemical characteristics of the formation fluids in the injection zone(s).

Upon completion, but prior to operation, the site operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):

IX. A pressure fall-off test and
X. A pump test or
XI. Injectivity tests.

7.3.8 INJECTION WELL OPERATING REQUIREMENTS

The following requirements follow U.S. EPA Regulation UIC Regulation § 146.88 (Injection well operating requirements; U.S. EPA, 2010c). Except during stimulation, the site operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Injection between the outermost casing protecting USDWs and the well bore is prohibited.

The site operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid. The site operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the jurisdictional authority has determined that such requirement might harm the integrity of the well or endanger USDWs.

Other than during periods of well workover (maintenance) approved by the jurisdictional authority in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the site operator must maintain mechanical integrity of the injection well at all times.

7.3.8.1 Monitoring and Shutdown

The site operator must install and use:

I. Continuous recording devices to monitor the injection pressure; the rate, volume and/or mass, and temperature of the CO_2 stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and
II. Alarms and automatic surface shut-off systems or, if approved by the jurisdictional authority, down-hole shut-off systems (e.g., automatic shut-off, check valves) for onshore wells or other mechanical devices that provide equivalent protection; and
III. Alarms and automatic down-hole shut-off systems for wells located offshore but within jurisdictional waters, designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit.

The site operator shall establish and maintain an emergency shut-down procedure. If a shutdown (down-hole or surface) is triggered, or if a loss of mechanical integrity is discovered, the operator shall implement this plan. The site operator or Project Proponent shall notify ACR within 2 weeks of any loss of mechanical integrity. A loss of mechanical integrity is has occurred when monitoring or testing shows significant leakage within the well casing, tubing, or packer, or significant fluid movement into a USDW through channels adjacent to the wellbore.

7.3.9 MECHANICAL INTEGRITY

The following requirements follow U.S. EPA UIC Regulation § 146.89 (Mechanical integrity; U.S. EPA, 2010c). All injection wells must have mechanical integrity, which means there is no significant leak in the casing, tubing, or packer; and there is no significant fluid movement into a USDW through channels adjacent to the injection well bore. To evaluate the absence of significant leaks site operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in Section 7.3.8.1.

At least once per year, the site operator must use an approved tracer survey (e.g., oxygen-activation log) or a temperature or noise log to determine the absence of significant fluid movement into a USDW.

If required by the jurisdictional authority, the site operator must run a casing inspection log to determine the presence or absence of corrosion in the long-string casing, or any other test to evaluate mechanical integrity. The Project Proponent shall include in the Monitoring Report the results of any mechanical integrity tests and shall include a description of the test(s), which shall include date, duration, and pressures (when applicable), and the test method(s) used.

7.3.10 TESTING AND MONITORING REQUIREMENTS

The following requirements follow U.S. EPA UIC Regulation § 146.90 (Testing and monitoring requirements; U.S. EPA, 2010c). The following Testing and Monitoring Plan shall be included in the MRV Plan:

I. Analysis of the CO_2 stream with sufficient frequency to yield data representative of its chemical and physical characteristics;
II. Installation and use, except during well workovers (maintenance), of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added;
III. Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance required by Section 7.3.6.1.;
    A. Analyzing coupons of the well construction materials placed in contact with the CO_2 stream; or
    B. Routing the CO_2 stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or
    C. Using an alternative method approved by the jurisdictional authority;
IV. Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of CO_2 movement through the confining zone(s) or additional identified zones including:

A. The location and number of monitoring wells based on specific information about the CCS project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and
B. The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected as required by Section 7.3.10 and on any modeling results in the area of review evaluation required by Section 7.3.5.

V. A demonstration of external mechanical integrity as required by Section 7.3.9 at least once per year until the injection well is plugged; and, if required by the jurisdictional authority, a casing inspection log pursuant to Section 7.3.9 at a frequency established in the Testing and Monitoring Plan;
VI. A pressure fall-off test at least once every five years unless more frequent testing is required by the jurisdictional authority based on site-specific information;
VII. Testing and monitoring to track the extent of the CO_2 plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:
A. Direct methods in the injection zone(s); and,
B. Indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO_2 detection tools), unless the jurisdictional authority has determined, based on site-specific geology, that such methods are not appropriate; and
VIII. Any and all additional monitoring required by the jurisdictional authority.

Monitoring during operation of the project shall include the maximum monitoring area and the active monitoring areas. The site operator shall periodically review the MRV Plan to incorporate monitoring data, operational data, and the most recent area of review re-evaluation.

7.3.11 WELL PLUGGING

The following requirements follow U.S. EPA UIC Regulation § 146.92 (Injection well plugging; U.S. EPA, 2010c). Prior to plugging a well, the site operator must flush each well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test.

As part of the submission of the MRV Plan for the first Reporting Period, the Project Proponent must prepare, maintain, and comply with a Well-Plugging Plan that is acceptable to the jurisdictional authority or ACR. The Well-Plugging Plan shall be included in the MRV Plan and shall contain the following information:

I. Appropriate tests or measures for determining bottomhole reservoir pressure;
II. Appropriate testing methods to ensure external mechanical integrity as specified in Section 7.3.9;
III. The type and number of plugs to be used;

IV. The placement of each plug, including the elevation of the top and bottom of each plug;

V. The type, grade, and quantity of material to be used in plugging. The material must be compatible with the CO_2 stream; and

VI. The method of placement of the plugs.

The Project Proponent must notify ACR in writing at least 60 days before plugging an injection well. At this time, if any changes have been made to the original well plugging plan, the site operator must also provide the revised well plugging plan.

Within 60 days after plugging, the Project Proponent must submit a plugging report to ACR. The report must be certified as accurate by the Project Proponent and by the person who performed the plugging operation (if other than the Project Proponent).

7.3.12 POST-INJECTION PERIOD, SITE CARE & SITE CLOSURE

Following cessation of CO_2 injection (i.e., following the injection period), monitoring shall be maintained during the post-injection period until the end of the Minimum Project Term to assure no emission of CO_2 to the atmosphere. The absence of emission of CO_2 to the atmosphere during the Minimum Project Term is considered assured when it can be verified that plume stabilization has been achieved, which occurs when CO_2 plume migration and pressure changes are small and predictable (meaning that any changes in the location of the plume are within the model uncertainty), there has been no detected migration of injected CO_2 across the boundaries of the geologic storage reservoir and the modeled scenarios out to 100 years indicate a high certainty that the CO_2 will remain contained within the geologic storage reservoir. The certainty of CO_2 remaining contained within the geologic storage reservoir will be demonstrated through sensitivity modeling out 100 years, with all modeled scenarios showing continuing CO_2 containment.

Specific monitoring tools shall be determined based on the site-specific experience gained during the pre-injection and operational phases of the project. With the cessation of injection and in the absence of any other changes to storage conditions, the pressures within the geologic storage reservoir should equilibrate and the movement of CO_2 within the reservoir should stabilize. Therefore, minimal lateral movement is expected and tracking of the lateral extent of the CO_2 plume through appropriate measurements (such as pressure) and modeling will be adequate. Due to buoyancy effects, the CO_2 plume will tend to migrate to the upper regions of the reservoir where it will be constrained by the confining layer. Changes in subsurface measurements made above the confining layer may be indicative of the migration of CO_2 outside of the geologic storage reservoir.

For ACR's purposes, the default minimum post-injection monitoring period for CCS projects is five (5) years after the end of the Crediting Period. During this period, subsurface pressure shall be recorded and changes in pressure evaluated to determine if these changes are consistent with expected or modeled changes, or if they are indicative of CO_2 emissions from the geologic storage reservoir. Other monitoring tools shall be implemented in accordance with the site's monitoring plan to assess plume stabilization. Project Proponents must still comply with all monitoring requirements as set by the applicable jurisdictional authority.

Although emission to the atmosphere has not necessarily occurred if the CO_2 migrates to regions outside the geologic storage volume boundaries, if it cannot be verified that plume stabilization has occurred, additional steps are necessary. If this occurs, Project Proponents may be required to redefine the boundaries of the storage volume. For example, if there is evidence of lateral movement outside the boundaries of the storage AoR, the lateral boundaries shall be extended to regions beyond the original storage AoR and the Project Proponent shall identify any new potential emissions pathways, remediate them, and modify the monitoring strategy to detect for emissions under new failure scenarios.

The following additional requirements follow U.S. EPA UIC Regulation § 146.93 (Post-injection site care and site closure; U.S. EPA, 2010c). As part of the submission of the MRV Plan for the first Reporting Period, the Project Proponent must prepare, maintain, and comply with a Post-Injection Site Care and Closure Plan that meets the requirements of this section and, if applicable, is approved by the jurisdictional authority.

This plan must include the following information:

I. The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);
II. The predicted position of the CO_2 plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under Section 7.3.5;
III. A description of post-injection monitoring location, methods, and proposed frequency; and
IV. A proposed schedule for submitting post-injection site care monitoring results to ACR.
V. Upon cessation of injection, Project Proponents must either submit an amended Post-Injection Site Care and Closure Plan or demonstrate through monitoring data and modeling results that no amendment to the plan is needed.

The Project Proponent must provide ACR with written notification prior to the commencement of site closure activities. Such notification must be provided to ACR at the same time as, or prior to, when similar notice is required to be given to the applicable jurisdictional authority(ies). At this time, if any changes have been made to the original Post-Injection Site Care and Closure Plan, the Project Proponent must also provide the revised plan.

Additionally, prior to the commencement of site closure activities, the Project Proponent must provide ACR evidence of adequate financial responsibility for site closure, as required by applicable law, regulation, or other legal requirement. Such evidence may consist of the documentation of the financial assurance provided to and accepted by the jurisdiction at the time of permitting with sensitive banking information redacted; this assurance may or may not be publicly available.

During site closure, the site operator must plug all monitoring wells in a manner which will not allow movement of injection or formation fluids that endangers a USDW. The Project Proponent must submit a Site Closure Report to ACR within 90 days of site closure, which must include:

VI. Documentation of appropriate injection and monitoring well plugging as specified in Section 7.3.11;
VII. A copy of a survey plat which indicates the location of the injection well relative to permanently surveyed benchmarks;
VIII. Documentation of appropriate notification and information to such federal, state or provincial, local, and Tribal authorities that have authority over drilling activities to enable such authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and
IX. Records reflecting the nature, composition, and volume of the CO_2 stream.

7.3.13 EMERGENCY AND REMEDIAL RESPONSE

The following requirements follow U.S. EPA Regulation UIC Regulation § 146.9 (146.94 Emergency and remedial response; U.S. EPA, 2010c). As part of the submission of the MRV Plan for the first Reporting Period, the Project Proponent must provide an Emergency and Remedial Response Plan that describes actions the injection site operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. If the site operator obtains evidence that the injected CO_2 stream and associated pressure front may cause an endangerment to a USDW or emit CO_2 from the geologic storage reservoir to the atmosphere, the injection site operator must:

I. Immediately cease injection;
II. Take all steps reasonably necessary to identify and characterize (including quantifying MT CO_2 emitted) any release;
III. Notify ACR within 24 hours of any emissions of CO_2 from the geologic storage reservoir to the atmosphere or any confirmed migration of CO_2 to a USDW; and
IV. Implement the Emergency and Remedial Response Plan.

The jurisdictional authority may allow the operator to resume injection prior to remediation if the injection site operator demonstrates that the injection operation will not compromise environment health. Eligibility for the issuance of ERTs under this Methodology is suspended upon confirmation of a release until such time as the jurisdictional authority authorizes recommencement of operations, the documentation of which shall be provided to ACR and the VVB.

The Project Proponent shall periodically review the Emergency and Remedial Response Plan no less often than once every five years. Based on this review, the Project Proponent shall submit an amended Emergency and Remedial Response Plan or demonstrate to ACR and the VVB that no amendment is needed.

7.4 Community Input & Environmental Impacts

ACR requires all Project Proponents to prepare and disclose an environmental and social impact assessment, mitigation of any negative impacts, and monitoring of any negative impacts and risks. ACR requires the use of the most recently published ACR Environmental and Social Impact Assessment Report template on the ACR website, provided within or as an appendix to the GHG Project Plan, for the assessment of environmental and social impacts of the Project, taking into account the scope and scale of the project activity and the mitigation measures.

Per *ACR Standard v8.0*, assessment shall include a review of risks and impact, as applicable, on terrestrial and marine biodiversity habitat and ecosystems; resource efficiency and pollution prevention including to air, water, soil and the ozone layer; the protection, conservation, or restoration of natural habitats such as forests, grasslands, and wetlands; labor rights and working conditions; gender equality; land acquisition and involuntary physical or economic displacement; and human rights and stakeholder engagement. Additional requirements apply to community-based projects.

The *ACR Standard* also discusses how identified risks are to be categorized, avoided, reduced, mitigated or compensated, commensurate with the risk. Project Proponents are required to detail how risks and negative impacts will be monitored, how often, and by whom.

8 Ownership and Injection & Storage Site Access

8.1 Title to Emission Reductions / Removals

Since CCS projects involve various processes—including but not limited to capture, compression, processing, transport, storage processes, and (for CO_2-EOR projects) oil production and use— which can be conducted by different companies, the ownership to the title of carbon credits associated with the project's emission reductions and/or removals must be clearly defined. This can be done through contracts among the parties in which one of the companies has clear ownership of the carbon credits or allocation to different owners is clear.

During the operational phase, documentation that traces the chain of custody of CO_2 as it is transferred from parties involved in movement of CO_2 through the project shall be established. This includes but is not limited to documents indicating the date (day, month, and year) and CO_2 volumes transferred and received by various operators involved in the project. The documentation shall be maintained by the Project Proponent and provided during verification. The documents shall be retained for a minimum period of three years following the end of the Crediting Period.

8.2 Pore Space Ownership and Mineral Rights

The Project Proponent must comply with all applicable legal requirements to secure necessary pore space ownership, occupancy, access and/or use and therefore may need to obtain perpetual storage rights to the subsurface pore space where CO_2 will be injected and stored, non-interference rights from mineral owners, and/or verifiable consent of surface owners. In both the U.S. and Canada, the acquisition of storage and other property rights related to pore space is governed under sub-national law (e.g., state or provincial law). In some jurisdictions, courts and legislatures have clarified that the owner of the surface property also has the right to use the pore space for permanent geologic storage while many other jurisdictions have not determined such rights to pore space use or ownership for geologic storage. Some jurisdictions permit severance of surface property rights, mineral estate rights, and pore space rights. In the case of CO_2-EOR projects, the right to inject CO_2 into the subsurface oil reservoir may be contained in and part of the oil and gas lease that would have been obtained to develop the project. In cases where mineral rights are severed from surface rights, it is likely that Project Proponents will need agreements with the mineral interest holder and the surface interest holder to inject CO_2. In such split estates, Project Proponents are encouraged to secure non-interference rights from mineral or pore space owners, or agreements of mutual consideration of interests with the aforementioned, to ensure that the injected CO_2 will not be interfered with. In fee estates, Project Proponents are encouraged to secure non-interference rights and perpetual rights of non-conveyance.

Additionally, migration of any injected fluid is only permissible provided the migration complies with regulations covering injection operations and does not interfere with pre-existing mineral recovery operations, cause damage to any adjacent subsurface and overlying surface properties, or endanger public health and safety. It is the Project Proponent's responsibility to ensure compliance with such applicable laws.

The Project Proponent must provide to ACR and the VVB an up-to-date (i.e., reflecting current laws, rules, and regulations) legal opinion from an attorney licensed in the relevant jurisdiction that (1) lists all relevant property owners and/or rights holders and the Project Proponent's agreements with each relative to the pore space; (2) describes the status and development of the law surrounding pore space rights the relevant jurisdiction(s), and (3) determines these agreements to be adequate relative to the interests of ensuring the permanent storage of injected and stored CO_2, and (4) determines that the Project Proponent has the legal authority to enter into and comply with the terms of the Reversal Risk Mitigation Contract or alternative risk mitigation assurance mechanism acceptable to ACR (see Section 9). In the event of a change in ownership of property or rights (whether owned or leased) or whenever conditions indicate that the Area of Review and Corrective Action Plan (Section 7.3.5) should be updated, the Project Proponent shall assess whether additional agreements with additional surface, subsurface, and mineral rights owners are required, or whether updates to current agreements, are required; Project Proponents shall enter into or update any such agreements as legally required or as is appropriate to ensure permanence.

8.3 Site Access

Project Proponents, third party verifiers, and ACR must have access to the site throughout the Minimum Project Term, including the post-injection monitoring period. All projects must demonstrate their right or permission to access the site and reservoir to conduct all monitoring and remediation requirements in this Methodology. In the case of CO_2-EOR, it is typical that mineral lease rights and associated surface use rights expire following the end of hydrocarbon production activities. Monitoring (and potential remediation) after the end of CO_2 injection activities is needed as part of assuring no emissions of CO_2 from the geologic storage reservoir. Project Proponents shall ensure that injection and storage site operators have continued access to the surface to conduct post-injection monitoring activities and, if necessary, remediation. Based on the site-specific monitoring planned for the post-injection period and associated surface access requirements, Project Proponents shall obtain needed surface use and/or access rights from the surface owners for the duration of the Minimum Project Term. This will usually entail surface use agreements similar to what is currently used to conduct groundwater sampling and remediation activities.

9 Permanence

For CCS projects, Project Proponents must demonstrate that the CO_2 captured and stored is permanently stored underground. Long-term liabilities arise from migration of the CO_2 plume, either vertically through well bores, fractures, or faults or horizontally by moving to points of emissions. Migration of CO_2 plumes might qualify as trespass or nuisance under state, provincial, or other jurisdictional law. Over time, project uncertainties can be greatly reduced.

The post-injection monitoring tasks described in Section 7.3.12 will be conducted for the Minimum Project Term defined in Section 4.3.4. Site characterization, site-specific modeling, and ongoing monitoring will allow for tracking of CO_2 plume migration and pressure changes through the post-injection period. As indicated in Section 7.3.12, plume stabilization is assured when it can be verified (by the VVB's qualified professional described in Section 7.3.1) that CO_2 plume migration and pressure changes are small and predictable, there has been no detected migration of injected CO_2 across the boundaries of the geologic storage reservoir, and modeled scenarios out to 100 years all indicate a high certainty that the CO_2 will remain contained within the geologic storage reservoir.

Projects must have effective reversal risk mitigation measures in place to avoid and compensate for any reversal. Risk mitigation measures include a legally binding ACR CCS Project Reversal Risk Mitigation Contract and Reserve Account contributions or an alternative risk mitigation mechanism approved by ACR. Prior to first credit issuance, the Project Proponent shall execute with ACR a Reversal Risk Mitigation Contract that applies to any activity occurring on the surface or in the subsurface and prohibits any activity that may result in the release of the stored CO_2 to the atmosphere (i.e., a reversal), including as a collateral effect of future hydrocarbon, mineral, or water resources development, unless measures are taken in advance to compensate for the reversal.

Each Reporting Period, the Project Proponent shall deposit a percent of the project's emission reductions and removals in the ACR-managed Reserve Account as determined by the ACR CCS Reserve Account Contribution Tool (exceptions may apply if the Project Proponent uses an ACR-approved alternate risk mitigation mechanism). If the Project Proponent is not the same entity as the Project Developer, the Project Developer shall facilitate the deposit of credits on behalf of the Project Proponent to meet obligations for the Reserve Account Contribution (and, if applicable) compensate for a reversal.

If CO_2 is emitted to the atmosphere from the geologic storage reservoir occurs at any time, the Project Proponent shall notify the appropriate jurisdictional authority and ACR. Remediation will be conducted in accordance with the Emergency and Remedial Response Plan (see Section 7.3.13) and any emissions to the atmosphere shall be conservatively quantified (see Sections 6.2.7) and compensated. If CO_2 is emitted to the atmosphere from the geologic storage reservoir during the injection period, then it shall be accounted for as project emissions in the same Reporting Period using Equation 35. In the event of a reversal, the quantity shall be measured and reported, verified, and compensated for following the requirements detailed in the Reversal Risk Mitigation Contract and the ACR Reserve Account Terms and Conditions or ACR approved alternate risk mitigation mechanism.

ACR will cancel credits from the Reserve Account for the balance of any amortized pre-Crediting Period construction emissions and post-injection period monitoring, decommissioning, and closure emissions in the event that the project does not complete its full Crediting Period.

10 Validation and Verification

Prior to ERT issuance, projects must be validated and verified by an ACR-approved Validation and Verification Body (VVB) in accordance with the *ACR Standard* and the *ACR Validation and Verification Standard*.

Projects must be validated and verified within the timelines established by the *ACR Standard*.

An in-person site visit by a VVB is required to be conducted at validation and, at minimum, every five project Reporting Periods or five years, whichever is earlier. The primary CO_2 source site(s); CO_2 capture, processing, and compression site(s); and CO_2 injection, storage, monitoring & hydrocarbon production and onsite processing site(s) must be visited as part of each site visit.

For Aggregated and Programmatic Development Approach projects, VVBs shall select and conduct in-person site visits as required by the *ACR Standard*.

In addition to the scope set out by the *ACR Standard* and the *ACR Validation and Verification Standard,* validations shall assess the following for conformance with the Methodology:

- Eligibility requirements;
- Additionality assessment and underlying documentation as relevant to regulatory surplus test and financial implementation barrier (if applicable);
- Physical boundary;
- GHG assessment boundary;
- Project temporal boundary;
- Net zero transition assessment (if applicable);
- Calculations of baseline emissions, project emissions, and emission reductions and/or removals, including the appropriate selection of baseline approach, application of alternative approaches, and selection, documentation, and application of emission factors and emissions-intensity metrics;
- Original underlying data and documentation as relevant and required to evaluate the GHG assertion;
- Data management systems and QA/QC procedures;
- Roles and responsibilities of participating entities (e.g., Project Proponent, facility owner(s), operator(s), owner(s) of subsurface rights); and
- MRV Plan (this can be validated by the VVB's qualified professional described in Section 7.3.1).

In addition to the scope set out by the *ACR Standard* and the *ACR Validation and Verification Standard,* verifications shall assess the following for conformance with the Methodology:

- Eligibility requirements;
- Additionality assessment and underlying documentation as relevant to any changes since validation relevant to the regulatory surplus test;
- Physical boundary;
- GHG assessment boundary;
- Project temporal boundary;
- Net zero transition assessment (if applicable);
- Calculations of baseline emissions, project emissions, and emission reductions and/or removals, including the appropriate selection of baseline approach, application of alternative approaches, and selection, documentation, and application of emission factors and emissions-intensity metrics;
- Original underlying data and documentation as relevant and required to evaluate the GHG assertion;
- Data management systems and QA/QC procedures;
- Roles and responsibilities of participating entities (e.g., Project Proponent, facility owner(s), operator(s), owner(s) of subsurface rights);
- Adherance to the MRV Plan; and
- Plume stabilization (verified by the VVB's qualified professional described in Section 7.3.1).

The Project Proponent must provide sufficient documentation and data to enable required validation and verification activities.

11 Periodic Reviews

ACR may require revisions to this Methodology to ensure that monitoring, reporting, and verification systems adequately reflect changes in CCS activities. This Methodology may also be periodically updated to reflect regulatory changes, emission factor revisions, or eligibility criteria. Before beginning a project, the Project Proponent shall ensure that they are using the latest version of the Methodology.

Definitions

For additional definitions of standard terms refer to the latest version of the *ACR Standard*.

Active Monitoring Area	The area that will be monitored (as required pursuant to 40 CFR Part 98 Subpart RR; U.S. EPA, 2010d) over a specific time interval (required to be at least one year) from the first year of the chosen monitoring period to the last year in the period. The boundary of the active monitoring area is established by superimposing two areas: 1. The area projected to contain the free phase CO_2 plume at the end of the monitoring period, plus an all-around buffer zone of one-half mile or greater if known CO_2 emission pathways extend laterally more than one-half mile, and 2. The area projected to contain the free phase CO_2 plume five years after the end of the monitoring period.
Anthropogenic CO_2	CO_2 emissions resulting from human activities, including the combustion of fossil-based hydrocarbons, industrial manufacturing, and land use changes.
Area of Review (AoR)	The region in a CCS project where underground sources of drinking water may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and displaced fluids, and is based on available site characterization, monitoring, and operational data.
Bioenergy	Energy derived from any physical form of biomass.
Bioenergy with Carbon Capture and Storage (BECCS)	Energy generation through combustion or fermentation of biomass with capture of associated CO_2 emissions and permanent storage in geologic storage reservoirs. BECCS is a subset of biomass with carbon removal and storage with the primary function being energy generation and the secondary function of storage. Additional details are in Appendix D.

Biogas	Gas that is produced from the breakdown of organic material in the absence of oxygen. Biogas is produced in processes including anaerobic digestion, anaerobic decomposition, thermochemical decomposition, and gasification.
Biogenic CO_2	CO_2 emissions released during the combustion, fermentation, or decomposition of biomass are considered biogenic CO_2.
Biomass	Organic material derived from recently living organisms or their metabolic byproducts. It includes plant matter (e.g., crop residues, wood), animal waste, and organic byproducts (e.g., black liquor, food waste).
Biomass with Carbon Removal and Storage (BiCRS)	CO_2 removal from the atmosphere through biomass and permanent storage in geologic storage reservoirs. BiCRS is an umbrella term comprising diverse approaches that take biomass and convert it for long-term carbon storage.
Captured Secondary CO_2	CO_2 produced from a secondary CO_2 source. Some of this CO_2 can be emitted but at least some of the CO_2 must have been captured.
Carbon Capture and Storage (CCS)	The separation and capture of carbon dioxide (CO_2) from industrial processes, biomass with carbon removal and storage (BiCRS), bioenergy with carbon capture and storage (BECCS), or the direct air capture (DAC) of atmospheric CO_2, and the transport and safe, permanent storage of the CO_2 in eligible geologic storage reservoirs.
Carbon Dioxide (CO_2)	A chemical compound composed of one carbon atom and two oxygen atoms. Carbon dioxide is a greenhouse gas and it can be captured and geologically stored.
Carbon Dioxide Removal (CDR)	CO_2 removal directly from the atmosphere through biological or technological means. Carbon dioxide removal includes direct air capture with CCS (DACCS), the use of sustainable biomass for bioenergy in combination with storage (bioenergy carbon capture and storage, or BECCS), or the use of sustainable biomass in combination with storage (biomass with carbon removal and storage, or BiCRS). To be eligible under this Methodology, biomass

	must meet the definition of "sustainable biomass" in accordance with Appendix D.
Carbon Dioxide Stream	CO_2 that has been captured from a CO_2 source (e.g., a power plant), plus incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process.
CO_2 Source	The specific power generation or industrial process (e.g., natural gas processing, hydrogen production, steelmaking) creating the captured CO_2.
Confining Zone(s)	Region(s) in the subsurface above the CO_2 storage volume that forms a nearly impenetrable layer to the upward migration of CO_2.
Corrective Action	The methods to ensure that wells within the area of review do not serve as conduits for the movement of fluids into underground sources of drinking water (USDW).
Depleted Oil and Gas Reservoir	A geologically defined subsurface zone that does not currently produce oil or gas and is considered to have no economically recoverable oil or gas with current technology. These reservoirs are not expected to produce oil or gas without a new production phase, including CO_2 injection or new technology.
Direct Air Capture (DAC)	The engineered and non-biological processes to capture CO_2 from the atmosphere through mechanical, chemical, or physical separation processes.
Enhanced Oil Recovery (EOR)	The process of enhancing the production of oil from subsurface reservoirs using thermal, gas, or chemical injection techniques. In this methodology, EOR concerns the injection of CO_2 into a producing oil reservoir (CO_2-EOR). Associated gas may be produced during the recovery of oil, but this production is incidental to the production of oil.

Excess CO_2	An increase in CO_2 produced as a result ofr non-compliance with air permits. The amount of excess CO_2 produced during such periods of non-compliance shall be calculated by comparing that amount of CO_2 produced during periods non-compliance to the amount of CO_2 produced during periods of compliance with air permits that are operating at the same rate of unit output (e.g., MWh, metric tons of clinker/hour) that was occurring during the period of non-compliance. If appropriate, the periods of compliance for comparison shall be within the same Reporting Period as the period of non-compliance. The CO_2 emissions (i.e., volume of gas from CO_2 source * concentration of CO_2 in the gas * density of CO_2) during periods of compliance shall be averaged and that value shall be compared to the CO_2 produced during the period of non-compliance. If the values during the period of non-compliance are 5% higher than the periods of compliance, all CO_2 during that period of non-compliance shall be considered "excess CO_2."
Exclusive Economic Zone	The region offshore of a country to which the country has the exclusive rights to marine resources and exploration (U.N., 1982). This region extends out to 200 nautical miles from a country's shoreline.
Failure Scenario	Possible scenarios under which CO_2 could be emitted to the atmosphere, resulting in geologic storage reservoir emissions (Section 6.2.7).
Forest Conversion	A lasting change of vegetation cover or composition of natural ecosystems, induced by human activity and characterized by significant loss of species diversity, habitat diversity, structural complexity or ecosystem functionality (FSC, 2019).
Fugitive Emissions	Emissions due to leaks or other irregular releases of gases or vapors from a pressurized environment or container. Examples of equipment that might experience fugitive emissions include flanges, valves, flow meters, and headers.

Functional Equivalence	The principle that dictates that project and baseline emissions are functionally equivalent if they provide the same function while delivering comparable products in quality and quantity.
Geologic Storage	The injection of CO_2 into a subsurface formation such as a deep saline reservoir, a depleted oil or gas reservoir, or an active oil reservoir, where it will remain safely and permanently stored.
Geologic Storage Reservoir	A three-dimensional confined region in the subsurface that encompasses the entire space that will be occupied by CO_2 in a storage project. Geologic storage reservoirs include saline reservoirs, depleted oil and gas reservoirs, and active oil reservoirs.
GHG, Sources, Sinks, and Reservoirs (SSRs)	GHG source – Physical unit or process that releases a GHG into the atmosphere. GHG sink – Physical unit or process that removes a GHG from the atmosphere. GHG reservoir - Physical unit or component of the biosphere, geosphere, or hydrosphere with the capability to store, accumulate, or release a GHG removed from the atmosphere by a GHG sink or captured from a GHG source.
High Conservation Value Forest	Forest that possesses one or more of the following attributes: • Forest areas containing globally, regionally or nationally significant concentrations of biodiversity values (e.g., endemism, endangered species, refugia); • Forest areas containing globally, regionally or nationally significant large landscape level forests, contained within, or containing the management unit, where viable populations of most if not all naturally occurring species exist in natural patterns of distribution and abundance; • Forest areas that are in or contain rare, threatened or endangered ecosystems; • Forest areas that provide basic services of nature in critical situations (e.g., watershed protection, erosion control);

	- Forest areas fundamental to meeting basic needs of local communities (e.g., subsistence, health); or - Forest areas critical to local communities' traditional cultural identity (areas of cultural, ecological, economic or religious significance identified in cooperation with such local communities). (WWF, n.d.).
Hub-and-Spoke Model	Infrastructure design where multiple CO_2-emitting sources (the spokes) are connected to a central facility (the hub) that handles the transportation and storage of the captured CO_2. This approach allows for shared infrastructure, reducing costs and risks associated with individual projects.
Industrial Source	A CO_2 emissions source that produces this GHG while manufacturing or processing products. Examples of industrial sources include cement production, iron, steel, aluminum, chemical, synthetic fuel, and hydrogen production; petrochemical manufacturing, refining, and gas processing; waste incineration; geothermal energy facilities; and pulp and paper manufacturing.
Injection Zone	A geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive CO_2 through a well or wells associated with a CCS project.
Intact Forest Landscape	A territory within today's global extent of forest cover which contains forest and non-forest ecosystems minimally influenced by human economic activity, with an area of at least 500 km^2 (50,000 ha) and a minimal width of 10 km (measured as the diameter of a circle that is entirely inscribed within the boundaries of the territory)(FSC, 2017).
Intensity-Based Baseline	A baseline represented by a regulatory-, technology-, or industry-specified emissions intensity metric or rate-based performance standard.
Maximum Monitoring Area	The area that must be monitored pursuant to 40 CFR Part 98 Subpart RR (U.S. EPA, 2010d) and is defined as equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2

	plume has stabilized plus an all-around buffer zone of at least one-half mile.
Methane (CH_4)	A chemical compound consisting of one carbon atom and four hydrogen atoms. Methane, a greenhouse gas, is the primary component in natural gas and can be biogenic (released from natural processes, livestock and agriculture, and anerobic breakdown of biomass) or thermogenic (released during production and transport of fossil fuels).
Monitoring, Reporting, and Verification (MRV) Plan	A verifiable project-specific plan which includes the monitoring and reporting requirements described in Section 7.3 of this methodology.
Nitrous Oxide (N_2O)	A chemical compound with one nitrogen atom and two oxygen atoms. Nitrous oxide is a greenhouse gas. Sources of N_2O include agriculture, fossil fuel combustion, wastewater management, and industrial processes.
Oil and Gas Reservoir	A geologically defined subsurface zone that currently produces oil and/or gas and is considered to have economically recoverable oil or gas with current technology.
Old-Growth Forest	The oldest seral stage in which a plant community is capable of existing on a site, given the frequency of natural disturbance events, which may include very old examples of long-lived early- or mid-seral species. The onset of old growth varies by forest community and region. Depending on the frequency and intensity of disturbances, and site conditions, old growth forests will have different structures, species compositions, age distributions, and functional capacities than younger forests. (FSC,2026).
Packer	A type of downhole tool used in oil, gas, or CO_2 injection wells to create a pressure-tight seal between the tubing (or casing) and the wellbore wall (casing or open hole). This seal isolates sections of the

	wellbore for operations such as production, injection, testing, or zonal isolation.
Post-Injection Site Care	Appropriate monitoring and other actions (including corrective action) needed following cessation of injection to ensure that USDWs are not endangered.
Pressure Front	The zone of elevated pressure that is created by the injection of CO_2 into the subsurface. For the purposes of this Methodology, the pressure front of a CO_2 plume refers to a zone where there is a pressure differential sufficient to cause the movement of injected fluids or formation fluids into a USDW.
Primary CO_2 Source	A CO_2 source that would have existed in the absence of the CCS project (e.g., electricity generating facility), the emissions of which exclude any separately quantifiable emissions (and/or captured CO_2) from secondary CO_2 sources and equipment. If CO_2 capture capabilities are added to a primary CO_2 source and the emissions and captured CO_2 of the associated capture equipment cannot be separately quantified from other primary CO_2 source emissions and captured CO_2, the increased emissions/captured CO_2 are considered part of primary CO_2 source emissions.
Primary CO_2 Source Emissions and/or Captured CO_2	CO_2 produced from a primary CO_2 source. This CO_2 can be emitted and/or captured.
Primary Forest	A naturally regenerated forest of native tree species where there are no clearly visible indications of human activities and the ecological processes are not significantly disturbed (U.N. F&AO, 2020).
Project-Based Baseline	A baseline that measures actual GHG emissions or removals from the project to represent what would have occurred in the absence of CCS assuming a consistent level of production or activity.
Reversal Risk Mitigation Contract	A legally binding agreement between ACR and the Project Proponent that serves to prevent, provide for the discovery of, and ensure

	compensation for activity occurring on the surface or in the subsurface that may result in a reversal. Refer to Section 9.
Saline Reservoir	An underground rock formation typically composed of porous sandstone or carbonate, saturated with saline water (brine), and isolated by an impermeable layer.
Secondary CO_2 Source	A CO_2 source of emissions and captured CO_2 that exists because of the CCS project and whose emissions and captured CO_2 can be quantified separately from primary CO_2 source emissions and captured CO_2.
Secondary CO_2 Source Emissions and/or Captured Secondary CO_2	CO_2 produced from a secondary CO_2 source. Some of this CO_2 can be emitted but at least some of the CO_2 must have been captured."
Site Closure	The point in time at which the operator of a geologic storage site is released from post-injection site care responsibilities by the jurisdictional authority.
Standard Conditions	A temperature of 60 degrees Fahrenheit and an absolute pressure of 1 atmosphere.
Standard Cubic Feet	A unit representing the amount of gas contained in a volume of one cubic foot at standard temperature and pressure.
Storage Volume	A space within the subsurface into which the project CO_2 is injected and where the injected CO_2 is stored permanently.
Sustainable Biomass	Biomass derived from forestry and crop-based agriculture fuels and feedstocks sourced within the United States and Canada that meet the criteria outlined in Appendix D.
Transmissive Fault or Fracture	A fault or fracture that has sufficient permeability and vertical extent to allow fluids to move between formations.
Underground Source of Drinking Water	An aquifer or its portion: **(a)** **(1)** Which supplies any public water system; or

(2) Which contains a sufficient quantity of ground water to supply a public water system; and

(i) Currently supplies drinking water for human consumption; or

(ii) Contains fewer than 10,000 mg/l total dissolved solids; and

(b) Which is not an exempted aquifer. (U.S. EPA, 1983)

Vented Emissions	Emissions through dedicated vent stacks during normal operation, process upsets, or shutdowns. These emissions can occur in the capture, transport, injection, and storage segments of the project and are calculated using procedures described in Section 6.2.

Appendix A: References

280 Earth. (n.d.). Projects. Retrieved August 29, 2025, from https://280.earth/projects/

Advanced Resources International (ARI). (2025, July 22). The U.S. CO_2 Enhanced Oil Recovery Survey: Updated to End-Of-Year 2023. https://www.adv-res.com/pdf/ARI-EOY-2023-CO2-EOR-Survey-JUL-22-2025.pdf

American Petroleum Institute (API). (2021). Manual of Petroleum Measurement Standards: Chapter 9–Density Determination and Chapter 11- Dynamic Link Library (API MPMS, 3rd ed.). American Petroleum Institute. https://www.api.org/~/media/files/publications/2020_catalog/petroleum_measurement.pdf

Argonne National Laboratory. (2025). R&D Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model® (2025 Excel) (Fuel-Cycle Model). U.S. Department of Energy Office of Energy Efficiency and Renewable Energy. https://greet.anl.gov/greet_1_series

Bruant, R. G., Guswa, A. J., Celia, M. A. & Peters, C. A. (2002). Safe Storage of CO_2 in Deep Saline Aquifers. Environmental Science & Technology, 36(11), 240A–245A. https://www.princeton.edu/~celia/cv4papers/Bruant et al - ES&T June 2002.html

Bryan, T. (2024). The CO_2 Report. Ethanol Producer Magazine. https://ethanolproducer.com/articles/the-co2-report

Canada Revenue Agency. (2024, October 18). Carbon Capture, Utilization, and Storage (CCUS) Investment Tax Credit (ITC). Government of Canada. https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/corporations/business-tax-credits/clean-economy-itc/carbon-capture-itc.html

Canadian Biogas Association & Agriculture & Agri-Food Canada (CBA & AAFC). (2018, February). Current Status and Future Potential of Biogas Production from Canada's Agriculture and Agri-Food Sector. (Rev. August 31, 2018). Canadian Biogas Association. https://farmingbiogas.ca/wp-content/uploads/2021/01/FINAL_Current_Status_and_Future_Potential_of_Biogas_Rev_August_31_2018.pdf

Canadian Standards Association (CSA). (2012/2022). Z741-12 (R2022): Geological Storage of Carbon Dioxide (Reaffirmed 2022) [Standard]. CSA Group. https://www.csagroup.org/store/product/2421962/

Carbon Capture Journal. (2024, June 21). Piñon Midstream secures approval for Dark Horse CCS project. https://www.carboncapturejournal.com/news/pion-midstream-secures-approval-for-dark-horse-ccs-project/6227.aspx

Environment and Climate Change Canada (ECCC). (2022). Reducing Methane Emissions from Canada's Municipal Solid Waste Landfills: Discussion paper (Catalogue No. En14 500/2022 1E PDF). https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/reducing-methane-emissions-canada-municipal-solid-waste-landfills-discussion.html

Environment and Climate Change Canada. (2024). Greenhouse Gas Reporting Program: Reported facility-level data (2022) [Data set]. Open Government Portal. https://open.canada.ca/data/en/dataset/a8ba14b7-7f23-462a-bdbb-83b0ef629823

https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system/federal-greenhouse-gas-offset-system/emission-factors-reference-values.htmlEnvironment and Climate Change Canada. (2025). National Inventory Report 1990–2023: Greenhouse Gas Sources and Sinks in Canada: Part 1 (Cat. No. En81-4/4E-PDF; ISSN 1910-7064; EC24186). Government of Canada. https://publications.gc.ca/collections/collection_2025/eccc/En81-4-2023-1-eng.pdf

Forest Stewardship Council (FSC). (n.d). What's in a label? https://fsc.org/en/label

Forest Stewardship Council. (2017, October 19). FSC Glossary of Terms. FSC--STD-01-002. https://connect.fsc.org/document-centre/documents/retrieve/d9dd3b64-73e9-4c81-925b-c104a3b84dba

Forest Stewardship Council. (2019). FSC Policy on Conversion. FSC-POL-01-007 V1-0. https://fsc.org/sites/default/files/2020-03/FSC-POL-01-007%20Policy%20on%20Conversion%20V1-0%20D1-0_EN.pdf

Forest Stewardship Council. (2026, January 1). FSC Forest Stewardship Standard for the Conterminous United States of America. FSC-STD-USA-02-2026. https://us.fsc.org/forest-management/revised-fscr-us-forest-stewardship-standard-v2

Global CCS Institute. (2024, November 6). Global Status of CCS 2024: Collaborating for a Net-Zero Future. https://www.globalccsinstitute.com/publications/global-status-of-ccs-2024/

Global Thermostat. (2023, April 4). Global Thermostat Unveils One of the World's Largest Units for Removing Carbon Dioxide Directly from Air. PR Newswire. https://www.prnewswire.com/news-releases/global-thermostat-unveils-one-of-the-worlds-largest-units-for-removing-carbon-dioxide-directly-from-air-301789992.html

Government of Alberta. (2023a, November 24). Alberta Carbon Capture Incentive Program. https://www.alberta.ca/alberta-carbon-capture-incentive-program

Government of Alberta. (2023b, June 15). Industrial Energy Efficiency and Carbon Capture, Utilization and Storage (IEE CCUS) Grant Program. https://www.alberta.ca/carbon-capture-utilization-and-storage-development-and-innovation

Government of Canada. (2021). Natural Gas Processing Plants [Data set]. Open Government – Canada. https://open.canada.ca/data/en/dataset/636b9550-3700-4e66-8259-5cfc8159a784/resource/f1efbeb4-7ea3-495b-8b7a-a534dbee978a

Government of Canada. (2022). 2030 Emissions Reduction Plan: Canada's Next steps for Clean Air and a Strong Economy [Report]. https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/emissions-reduction-2030/plan.html

Heimdal Inc. (2024, January 24). Heimdal Announces Landmark Partnership to Locate Direct Air Capture Facility at CapturePoint's Oklahoma Carbon Hub. PR Newswire/Heimdal. https://www.heimdalccu.com/news/heimdal-announces-landmark-partnership-to-locate-direct-air-capture-facility-at-capturepoints-oklahoma-carbon-hub

Heirloom Carbon Technologies. (2023, November 9). Heirloom Unveils America's First Commercial Direct Air Capture Facility. https://www.heirloomcarbon.com/news/heirloom-unveils-americas-first-commercial-direct-air-capture-facility

Intergovernmental Panel on Climate Change (IPCC). (2006). 2006 IPCC Guidelines for National Greenhouse Gas Inventories. https://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html

Intergovernmental Panel on Climate Change. (2012). Renewable energy sources and climate change mitigation: Special report of the Intergovernmental Panel on Climate Change. Cambridge University Press. https://www.ipcc.ch/report/renewable-energy-sources-and-climate-change-mitigation/

Intergovernmental Panel on Climate Change. (2013). Fifth Assessment Report (AR5). Climate Change 2013: The Physical Science Basis. Chapter 8SM – Anthropogenic and Natural Radiative Forcing – Supplementary Material. Table 8.SM.16. https://www.ipcc.ch/site/assets/uploads/2018/07/WGI_AR5.Chap_.8_SM.pdf

Intergovernmental Panel on Climate Change. (2022). Climate Change 2022: Mitigation of Climate Change. Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change (P. R. Shukla et al., Eds.). Cambridge University Press. https://www.ipcc.ch/report/ar6/wg3/

Intergovernmental Panel on Climate Change. (2023). Climate Change 2023: Synthesis Report. Contribution of Working Groups I, II and III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change (Core Writing Team, H. Lee & J. Romero, Eds.). https://www.ipcc.ch/report/ar6/syr/downloads/report/IPCC_AR6_SYR_LongerReport.pdf

International Civil Aviation Organization (ICAO). (2025, June). CORSIA Methodology for Calculating Actual Life Cycle Emissions Values. https://www.icao.int/sites/default/files/environmental-protection/CORSIA/Documents/CORSIA%20Eligible%20Fuels/ICAO-document-07-Methodology-for-Actual-Life-Cycle-Emissions-June-2025.pdf

International Energy Agency (IEA). (2015). Storing CO_2 through Enhanced Oil Recovery. https://www.iea.org/reports/storing-co2-through-enhanced-oil-recovery

International Energy Agency. (2021, May). Net Zero by 2050: A Roadmap for the Global Energy Sector. https://www.iea.org/reports/net-zero-by-2050

International Organization for Standardization (ISO). (2006). ISO 14025:2006: Environmental labels and declarations — Type III environmental declarations — Principles and procedures. https://www.iso.org/standard/38131.html

International Organization for Standardization. (2017). ISO 27914: Carbon Dioxide Capture, Transportation and Geological Storage — Geological Storage. https://www.iso.org/standard/64148.html

Kuuskraa, V.A., Godec, M.L & Dipietro, P. (2013). CO_2 Utilization from “Next Generation” CO_2 Enhanced Oil Recovery Technology: Energy Procedia 00 (2013) 00-000. https://www.adv-res.com/pdf/CO2%20Utilization%20from%20_Next%20Generation_%20CO2%20Enhanced%20Oil%20Recovery%20Technology.pdf

Natural Resources Canada. (2024, October 18). Energy Innovation Program: Carbon Capture, Utilization and Storage (CCUS) & Hydrogen Funding Call. Government of Canada. https://natural-resources.canada.ca/funding-partnerships/energy-innovation-program

Ontario Ministry of Natural Resources. (2025, May). Schematic Diagram of Geologic Carbon Storage in a Depleted Oil and Gas Reservoir and a Deep Saline Aquifer [Diagram] in Geologic Carbon Storage [pamphlet].

Roundtable on Sustainable Biomaterials Association (RSB). (2023, December 1). RSB Standard for Advanced Fuels. RSB-STD-01-010. https://rsb.org/wp-content/uploads/2024/06/RSB-STD-01-010-RSB-Standard-for-advanced-fuels.pdf

Shacat, J., Willis, J.R. & Ciavola, B. (2022, June). GHG Emissions Inventory for Asphalt Mix Production in the United States: Current Industry Practices and Opportunities to Reduce Future Emissions.

National Asphalt Pavement Association, SIP-106. https://www.asphaltpavement.org/uploads/documents/Sustainability/SIP-106_GHG_Emissions_Inventory_for_Asphalt_Mix_Production_in_the_US_%E2%80%93_NAPA_June_2022.pdf

Sustainable Forestry Initiative (SFI). (n.d.). SFI On-Product Labels. https://forests.org/labelsandclaims/

United Nations (U.N.). (1982). United Nations Convention on the Law of the Sea. https://www.un.org/depts/los/convention_agreements/texts/unclos/unclos_e.pdf

United Nations Food and Agriculture Organization (U.N. F&AO). (2020). Global Forest Resources Assessment 2020: Terms and Definitions: Forest Resources Assessment Working Paper 188. https://openknowledge.fao.org/server/api/core/bitstreams/531a9e1b-596d-4b07-b9fd-3103fb4d0e72/content

U.S. Congress. (2022, August 16). H.R. 5376 – 117th Congress: Inflation Reduction Act of 2022. https://www.congress.gov/bill/117th-congress/house-bill/5376

U.S. Department of Energy (DOE). (2021). Carbon Capture, Utilization, and Storage: Climate Change, Energy & Economic Opportunity (Chap. 8, "CO_2-Enhanced Oil Recovery"). Office of Fossil Energy and Carbon Management. https://www.energy.gov/sites/default/files/2022-10/CCUS-Chap_8-030521.pdf

U.S. Department of Energy, National Energy Technology Laboratory (U.S. DOE NETL). (2015). Carbon Storage Atlas: Fifth Edition (Atlas V). https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf.

U.S. Department of the Treasury, Internal Revenue Service (IRS). (2021, January 15). Credit for Carbon Oxide Sequestration; Final Rule. Federal Register, 86(10), 4728–4754, 26 CFR Part 1, RIN 1545-BP42. https://www.federalregister.gov/documents/2021/01/15/2021-00302/credit-for-carbon-oxide-sequestration

U.S. Energy Information Administration. (2022). Assumptions to the Annual Energy Outlook 2022: Oil and Gas Supply Module. https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf

U.S. Environmental Protection Agency (U.S. EPA). (1983, April 1). 40 CFR Part 144.3 - Underground source of drinking water (USDW). https://www.ecfr.gov/current/title-40/part-144/section-144.3#p-144.3(Underground%20source%20of%20drinking%20water%20(USDW))

U.S. Environmental Protection Agency. (2009, October 30). Mandatory Greenhouse Gas Reporting: 40 CFR Part 98 Subpart C—General Stationary Fuel Combustion Sources. Electronic Code of Federal Regulations. https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-C

U.S. Environmental Protection Agency. (2010a, November). General Technical Support Document for Injection and Geologic Sequestration of Carbon Dioxide: Subparts RR and UU, Greenhouse Gas Reporting Program (Chapters 4 & 5). https://www.epa.gov/sites/production/files/2015-07/documents/subpart-rr-uu_tsd.pdf

U.S. Environmental Protection Agency. (2010b, November 30). Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, Final Rule: Subpart W. https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-W

U.S. Environmental Protection Agency. (2010c, December 10).Underground Injection Control (UIC) Program: 40 CFR Part 146 Subpart H—Criteria and Standards Applicable to Class VI Wells. Electronic Code of Federal Regulations. https://www.ecfr.gov/current/title-40/chapter-I/subchapter-D/part-146/subpart-H/

U.S. Environmental Protection Agency. (2010d, December 10). Mandatory Greenhouse Gas Reporting: 40 CFR Part 98 Subpart RR—Geologic Sequestration of Carbon Dioxide. Electronic Code of Federal Regulations. https://www.ecfr.gov/current/title-40/part-98/subpart-RR

U.S. Environmental Protection Agency. (2014, November). Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources. https://www.epa.gov/sites/default/files/2016-08/documents/framework-for-assessing-biogenic-co2-emissions.pdf

U.S. Environmental Protection Agency. (2021, October). U.S. Cement Industry Carbon Intensities (2019). EPA 430-F-21-004. https://www.epa.gov/system/files/documents/2021-10/cement-carbon-intensities-fact-sheet.pdf

U.S. Environmental Protection Agency. (2024, October). Greenhouse Gas Reporting Program: 2023 Data Summary Spreadsheets (zip) [Data set]. https://www.epa.gov/system/files/other-files/2024-10/2023_data_summary_spreadsheets.zip

U.S. Environmental Protection Agency. (2025a, January 15). Emission Factors for Greenhouse Gas Inventories. https://www.epa.gov/system/files/documents/2025-01/ghg-emission-factors-hub-2025.pdf

U.S. Environmental Protection Agency. (2025b, May 19). Mandatory Greenhouse Gas Reporting: 40 CFR Part 98 Subpart A—General Provision. Electronic Code of Federal Regulations. https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-A

U.S. Environmental Protection Agency. (2025c, June 24). Types of Anaerobic Digesters. https://www.epa.gov/anaerobic-digestion/types-anaerobic-digesters

U.S. Environmental Protection Agency. (2025d, September 12). Project and Landfill Data by State. Landfill Methane Outreach Program (LMOP). https://www.epa.gov/lmop/project-and-landfill-data-state

U.S. Environmental Protection Agency. (2025e, November 13). AgSTAR Data and Trends. U.S. Environmental Protection Agency. https://www.epa.gov/agstar/agstar-data-and-trends#adfacts

U.S. Executive Office of the President. (2021, October). The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050. White House. https://bidenwhitehouse.archives.gov/wp-content/uploads/2021/10/US-Long-Term-Strategy.pdf

World Steel Association. (2023a, June.) Worldsteel LCA Eco-Profile Global: Cold Rolled Coil. https://worldsteel.org/wp-content/uploads/Cold-rolled-coil-Global-Construction.pdf

World Steel Association. (2023b, June.) Worldsteel LCA Eco-Profile Global: Electrogalvanised Steel. https://worldsteel.org/wp-content/uploads/Electrogalvanised-steel-Global-Construction.pdf

World Steel Association. (2023c, June.) Worldsteel LCA Eco-Profile Global: [Electrolytic Chromium Coated Steel] ECCS. https://worldsteel.org/wp-content/uploads/Electrolytic-chromium-coated-steel-Global-Construction.pdf

World Steel Association. (2023d, June) Worldsteel LCA Eco-Profile Global: Engineering Steel. https://worldsteel.org/wp-content/uploads/Engineering-steel-Global-Construction.pdf

World Steel Association. (2023e.) Worldsteel LCA Eco-Profile Global: Finished Cold Rolled Coil. https://worldsteel.org/wp-content/uploads/Finished-cold-rolled-coil-Global-Construction.pdf

World Steel Association. (2023f.) Worldsteel LCA Eco-Profile Global: Hot-Dip Galvanized Coil. https://worldsteel.org/wp-content/uploads/Hot-dip-galvanised-coil-Global-Construction.pdf

World Steel Association. (2023g.) Worldsteel LCA Eco-Profile Global: Hot Rolled Coil. https://worldsteel.org/wp-content/uploads/Hot-rolled-coil-Global-Construction.pdf

World Steel Association. (2023h.) Worldsteel LCA Eco-Profile Global: Organic Coated Steel. https://worldsteel.org/wp-content/uploads/Organic-coated-Steel-Global-Construction.pdf

World Steel Association. (2023i.) Worldsteel LCA Eco-Profile Global: Pickled Hot Rolled Coil. https://worldsteel.org/wp-content/uploads/Pickled-hot-rolled-coil-Global-Construction.pdf

World Steel Association. (2023j.) Worldsteel LCA Eco-Profile Global: Plate. https://worldsteel.org/wp-content/uploads/Plate-Global-Construction.pdf

World Steel Association. (2023k.) Worldsteel LCA Eco-Profile Global: Rebar. https://worldsteel.org/wp-content/uploads/Rebar-Global-Construction.pdf

World Steel Association. (2023l.) Worldsteel LCA Eco-Profile Global: Seamless Pipe. https://worldsteel.org/wp-content/uploads/Seamless-pipe-Global-Construction.pdf

World Steel Association. (2023m.) Worldsteel LCA Eco-Profile Global: Sections. https://worldsteel.org/wp-content/uploads/Sections-Global-Construction.pdf

World Steel Association. (2023n.) Worldsteel LCA Eco-Profile Global: Tinplate. https://worldsteel.org/wp-content/uploads/Tinplate-Global-Construction.pdf

World Steel Association. (2023o.) Worldsteel LCA Eco-Profile Global: UO Pipe. https://worldsteel.org/wp-content/uploads/UO-pipe-global-Construction.pdf

World Steel Association. (2023p.) Worldsteel LCA Eco-Profile Global: Welded Pipe. https://worldsteel.org/wp-content/uploads/Welded-pipe-Global-Construction.pdf

World Steel Association. (2023q.) Worldsteel LCA Eco-Profile Global: Wire Rod. https://worldsteel.org/wp-content/uploads/Wire-rod-Global-Construction.pdf

World Steel Association. (2026) Sustainability Indicators Report 2025. Sustainability-Indicators-publication-2025_Feb-2026.pdf

WWF. (n.d.). High Conservation Value Forests. https://wwfeu.awsassets.panda.org/downloads/hcvffinal.pdf

Appendix B: Produced Oil Emission Factors (U.S.)

In addition to accounting for the emissions associated with oil production (refer to Section 6.2.3), emissions from transport, refining, and end use of oil produced from CO_2-EOR are accounted for as project emissions (refer to Section 6.2.6 for equations). This appendix describes the emission factors that shall be applied to the equations in Section 6.2.6 for projects with geologic reservoirs in the U.S. Refer to Table 15 in Section B.4 of this appendix for an example of how to calculate the emissions factor used in Section 6.2.6.

B.1 Oil Transport Emissions

Step A: Use Figure 4 and Table 8, Column 1, to find the relevant National Energy Modeling System (NEMS) region. Use the respective row in Table 10, Column 22 for field-to-refinery transport emissions for each NEMS region. Table 17 may be used as a substitute for Table 10 if a producer knows the specific transportation modes and distances for crude oil or products. Enter this value into $\mathbf{EF_{Oil-Transpo-Refinery_{g,t}}}$ in Equation 32.

Figure 4: Map of the National Energy Modeling System Oil and Gas Supply Regions for the U.S.[68]

[68] Image from (U.S. Energy Information Administration, 2022).

Table 8: Crude Oil Domestic Transport GHG Emissions—from Field to Refinery (Regional Weighted Averages)[69]

	AVERAGE CHARACTERISTICS					
1. REGION	2. API GRAVITY	3. HEAT CONTENT MMBTU/ BBL	4. DENSITY KG/CUBIC METER	5. BBL/ METRIC TON	6. 2020 PRODUCTION MMBPD	7. 2020 PRODUCTION METRIC KTON
United States	**40.7**	**5.6**	**823.7**	**7.64**	**11.310**	**542,999**
Onshore East	50.9	5.3	779.0	8.07	0.158	7,138
Onshore Gulf Coast	36.7	5.7	844.1	7.45	1.431	70,090
Onshore Midcontinent	43.1	5.5	812.3	7.74	0.612	28,843
Onshore Southwest	42.8	5.5	813.1	7.74	4.490	211,861
Onshore Rocky Mountain	44.6	5.5	806.0	7.80	0.809	37,848
Onshore Northern Great Plains	43.7	5.5	808.4	7.78	1.204	56,479
Onshore West Coast	25.5	6.0	902.6	6.97	0.365	19,126
GOM State	32.6	5.8	863.1	7.29	0.020	989
GOM Fed Shallow	32.6	5.8	863.1	7.29	0.138	6,920
GOM Fed Deep	32.6	5.8	863.1	7.29	1.609	80,571
Pac Off State	38.0	5.7	837.6	7.51	0.020	972
Pac Off Federal	38.0	5.7	837.6	7.51	0.010	486
AK Onshore	37.7	5.7	841.1	7.48	0.355	17,340
AK State Offshore	37.7	5.7	841.1	7.48	0.089	4,335
AK Federal Offshore	37.7	5.7	841.1	7.48	0.000	0

[69] This table presumes transport to domestic refining locations. Table 9 accounts for transport of crude oil to refineries outside the U.S.

Table 8 (continued)

1. REGION	8. AVERAGE DISTANCE	9. IMPLIED MILLION METRIC TON-MILES	10. TRUCK MILES	11. RAIL MILES	12. BARGE WATER MILES	13. OCEAN TANKER WATER MILES	14. PIPELINE MILES	15. TRUCK METRIC TON-MILES 10^6	16. RAIL METRIC TON-MILES 10^6	17. BARGE WATER METRIC TON-MILES 10^6	18. OCEAN TANKERS WATER METRIC TON-MILES 10^6	19. PIPELINE METRIC TON-MILES 10^6 [70]	20. WEIGHTED AVG. PIPELINE FACTOR G CO_2e/METRIC TON-MILE	21. CRUDE TRANSPORT EMISSIONS 10^6 METRIC TONS CO_2e	22. CRUDE TRANSPORT WITHIN U.S. CO_2e KG/BBL
United States	**689**	**373,885**	**14**	**40**	**22**	**118**	**494**	**7,780**	**21,716**	**11,897**	**64,015**	**268,477**	**21.4**	**9,401**	**2.28**
Onshore East	341	2,435	18				323	129	-	-		2,306	22.3	73	1.26
Onshore Gulf Coast	309	21,648	18	5	20		266	1,264	350	1,380		18,654	21.1	699	1.34
Onshore Midcontinent	605	17,439	18				587	520	-	-		16,919	24.5	500	2.24
Onshore Southwest	682	144,481	18		20		644	3,821	-	4,171		136,489	22.2	3,896	2.38
Onshore Rocky Mountain	713	26,970	18	6			688	683	236	-		26,051	25.5	790	2.67
Onshore Northern Great Plains	859	48,541	18	374			467	1,019	21,130	-		26,392	24.7	2,008	4.57
Onshore West Coast	227	4,332	18				208	345	-	-		3,988	15.8	119	0.90
GOM State	61	60	-				61	-	-	-		60	20.5	1	0.17
GOM Fed Shallow	189	1,308	-				189	-	-	-		1,308	20.5	27	0.53
GOM Fed Deep	309	24,924	-		79		231	-	-	6,346		18,578	20.5	744	1.27
Pac Off State	229	223	-				229	-	-	-		223	16.2	4	0.49
Pac Off Federal	258	125	-				258	-	-	-		125	16.2	2	0.56
AK Onshore	3,753	65,084	-			2,953	800	-	-	-	51,212	13,872	23.4	718	5.54
AK State Offshore	3,763	16,314	-			2,953	810	-	-	-	12,803	3,511	23.4	181	5.57
AK Federal Offshore	3,773	0	-			2,953	820	-	-	-	0	0	23.4	0	5.60
Emission factor in grams/metric ton-mile								**163.3**	**56.3**	**57.2**	**7.7**	**21.4**			

[70] Pipeline is weighted 90% electric drive and 10% diesel drive.

Step B: Approximately 29% of U.S. crude is exported outside of the U.S. To account for this in a default manner, 2.2 CO_2e kg/bbl (e.g., 29% of 7.7 CO_2e kg/bbl; refer to Table 10, bottom of Column 8 for the default international transport emission factor) shall be added to the domestic transport emission factor. If all the crude is expected to be transported outside of the U.S., as proven through supporting documentation from the Project Proponent, 7.7 CO_2e kg/bbl shall be added in the default method. If the country to which the crude is going is known, the value for that specific country shall be used, multiplied by the percentage being exported. It is unlikely that international destinations for crude will be known. Enter this value into $\mathbf{EF_{Oil-Crude-Export_{g,t}}}$ in Equation 32.

Table 9: Crude Oil Exports Transport GHG Emissions

U.S. CRUDE OIL EXPORTS 2020 (MILLION METRIC TONS)				GHG EMISSIONS			
1. DESTINATION	2. 10^6 METRIC TONS	3. DISTANCE IN STATUTE MILES	4. 10^6 METRIC TON-MILES	5. EMISSION FACTOR OCEAN TANKER GRAMS/METRIC TON-MILES	6. GHG EMISSION (CO_2e 10^6 METRIC TONS)	7. CO_2e KG/ METRIC TON	8. CO_2e KG/BBL
Canada	21.3	1,658	35,361	7.7	0.27	12.8	1.68
Mexico	0.0	336	-	7.7	-		
U.S.	0.0	0	-	7.7	-		
S. & Cent. America	8.5	3,469	29,635	7.7	0.23	26.8	3.51
Europe	57.9	6,873	398,185	7.7	3.08	53.1	6.96
Russia	0.0	8,632	0	7.7	0.00	66.7	8.74
Other CIS	0.1	9,459	774	7.7	0.01	73.1	9.57
Middle East	1.9	10,052	19,036	7.7	0.15	77.7	10.17
Africa	0.2	6,795	1,163	7.7	0.01	52.5	6.88
Australasia	3.3	10,448	34,569	7.7	0.27	80.7	10.57
China	19.8	9,890	195,392	7.7	1.51	76.4	10.01
India	10.7	11,617	124,193	7.7	0.96	89.8	11.76
Japan	2.0	8,627	17,087	7.7	0.13	66.7	8.73
Singapore	2.7	11,144	30,490	7.7	0.24	86.1	11.28
Other Asia Pacific	26.9	10,956	294,334	7.7	2.27	84.7	11.09
Total	**155.3**	**7,600**	**1,180,218**	**7.7**	**9.12**	**58.7**	**7.7**
Average percent of U.S. production that was exported						**29%**	**29%**
“Adder” above domestic transport GHGs to account for exported crudes and condensates						**16.80**	**2.20**
NOTE: CO_2e kg/bbl calculated using weighted average 7.64 barrels per metric ton for U.S. production.							

Step C: Use the Table 10, Column 18 default value in red (4.35 CO_2e kg/bbl) for transport emissions from refinery to wholesale terminals. Enter this value into $\mathbf{EF_{Oil-Transpo-Terminals_{g,t}}}$ in Equation 32.

Table 10: Refined Petroleum Product Domestic Transport GHG Emissions—from Refinery to Wholesale Terminals

1. DOMESTIC TRANSPORT OF PETROLEUM PRODUCTS FROM U.S. REFINERIES	2. BBL/ METRIC TON	3. 2020 PRODUCTION MMBPD	4. 2020 PRODUCTION METRIC KTON	5. AVERAGE DISTANCE	6. TRUCK MILES	7. RAIL MILES	8. BARGE WATER MILES	9. OCEAN TANKER WATER MILES	10. PIPELINE MILES	11. TRUCK METRIC TON-MILES 10^6	12. RAIL METRIC TON-MILES 10^6	13. BARGE WATER METRIC TON-MILES 10^6	14. OCEAN TANKERS WATER METRIC TON-MILES 10^6	15. PIPELINE METRIC TON-MILES 10^6	16. TOTAL METRIC TON-MILES 10^6	17. DOMESTIC TRANSPORT EMISSIONS 10^6 METRIC TONS CO_2e	18. PRODUCT TRANSPORT WITHIN U.S. CO_2e KG/BBL
United States	8.01	17.39	792,467	336	179	30	39	2	85	141,984	23,818	31,208	1,643	67,559	266,211	27,611	4.35
Emission factor in grams/metric ton-mile (pipeline is weighted 100% electric drive)										**163.3**	**56.3**	**57.2**	**7.7**	**19.0**			

Step D: Use the Table 11 default value in red (1.51 CO_2e kg/bbl) for transport emissions for exported refined petroleum products. About 31% of U.S. refinery outputs are exported as refined petroleum products. Enter this value into $\mathbf{EF_{Oil-Transpo-Refined-Export_{g,t}}}$ in Equation 32.

Table 11: Refined Petroleum Product Export Transport GHG Emissions

U.S. PETROLEUM PRODUCT EXPORTS 2020 (MILLION TONS)				GHG EMISSIONS			
1. DESTINATION	2. 10^6 METRIC TONS	3. DISTANCE IN STATUTE MILES	4. 10^6 METRIC TON-MILES	5. EMISSION FACTOR OCEAN TANKER GRAMS/METRIC TON-MILES	6. GHG EMISSION (CO_2e 10^6 METRIC TONS)	7. CO_2e KG/METRIC TON	8. CO_2e KG/BBL
Canada	24.4	1,658	40,506	7.7	0.31	12.8	1.64
Mexico	49.9	336	16,789	7.7	0.13	2.6	0.33
U.S.	0.0	0	-	7.7	-		
S. & Cent. America	71.8	3,469	249,068	7.7	1.92	26.8	3.42
Europe	24.6	6,873	169,160	7.7	1.31	53.1	6.78
Russia	0.0	8,632	9	7.7	0.00	66.7	8.52
Other CIS	0.0	9,459	31	7.7	0.00	73.1	9.33
Middle East	2.1	10,052	20,833	7.7	0.16	77.7	9.92
Africa	6.2	6,795	42,191	7.7	0.33	52.5	6.70
Australasia	1.5	10,448	15,259	7.7	0.12	80.7	10.31
China	8.6	9,890	84,837	7.7	0.66	76.4	9.76
India	9.6	11,617	111,177	7.7	0.86	89.8	11.46
Japan	12.1	8,627	104,591	7.7	0.81	66.7	8.51
Singapore	3.7	11,144	41,602	7.7	0.32	86.1	10.99
Other Asia Pacific	25.6	10,956	280,906	7.7	2.17	84.7	10.81
Total	**240.2**	**4,901**	**1,176,959**	**7.7**	**9.10**	**37.9**	**4.83**
Average percent of U.S. refinery output that was exported						**31%**	**31%**
“Adder” above domestic transport GHGs to account for exported petroleum products						**11.86**	**1.51**
NOTE: CO_2e kg/bbl calculated using weighted average 7.83 barrels per metric ton for U.S. production.							

B.2 Oil Refining Emissions

Step E: Use the following equations to calculate the API gravity of crude oil.

Equation 42: Specific Gravity of Crude

$$SG_{Crude_{g,t}} = \frac{\rho Crude_{g,t}}{\rho Water_{STP}}$$

WHERE

$SG_{Crude_{g,t}}$	Specific gravity of crude oil produced from geologic reservoir **g** in Reporting Period **t**.
$\rho Crude_{g,t}$	Density of crude oil produced from geologic storage reservoir **g**, measured at (or corrected to) standard conditions at the site of production, in Reporting Period **t** (kg/m^3).
$\rho Water_{STP}$	Density of water measured at standard conditions = 999 kg/m^3.

Equation 43: API Gravity Formula[71]

$$APIG_{Crude_{g,t}} = \frac{141.5}{SG_{Crude_{g,t}}} - 131.5$$

WHERE

$APIG_{Crude_{g,t}}$	API gravity of crude oil from geologic storage reservoir **g** in Reporting Period **t** (° API).
$SG_{Crude_{g,t}}$	Specific gravity of crude oil produced from geologic reservoir **g** in Reporting Period **t** (unitless).
141.5	Empirical value that standardizes the conversion of specific gravity at 60 °F into degrees API.

[71] (API, 2021)

131.5	Empirical value that standardizes the conversion of specific gravity at 60 °F into degrees API.

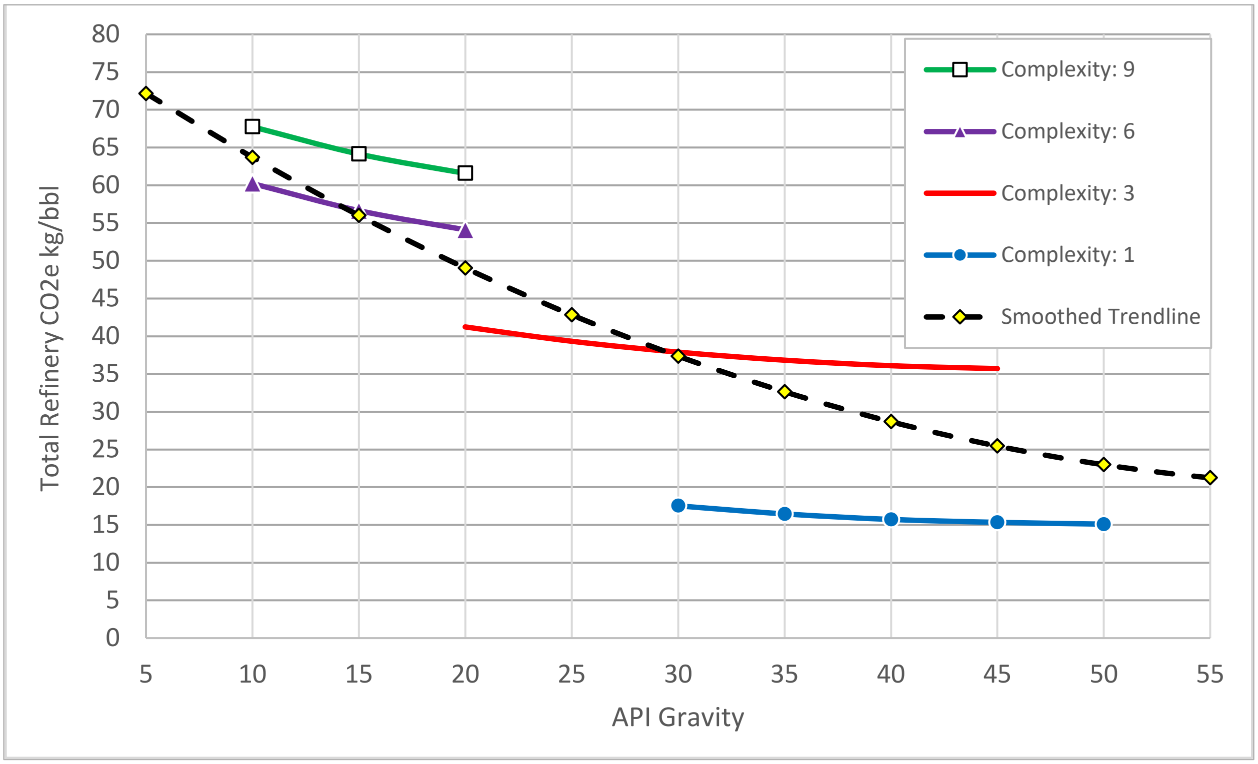
Use Table 12, Column 2 to identify the relevant API gravity for each Reporting Period **t**. Use Column 3 in the corresponding row for emissions from refining. Alternatively, the value can be read off Figure 5, which shows the smoothed trendline referenced in Table 12.

This value is entered into Equation 31 as the term $EF_{Oil-Refining_{g,t}}$.

Table 12: Petroleum Product Refining GHG Emissions

1. CLASSIFICATION	2. AVERAGE API GRAVITY OF CRUDE (° API)	3. REFINERY CO_2e KG/BBL (SMOOTHED TRENDLINE)	4. CRUDE INPUTS BY CATEGORY AS % OF ALL U.S. CRUDE INPUTS
Extra Heavy	5.5	71.28	0.22%
Heavy	12.5	59.76	7.15%
Heavy	17.5	52.43	10.30%
Heavy	22.5	45.84	10.14%
Medium	27.5	40.00	15.41%
Medium	32.5	34.91	12.91%
Light	37.5	30.57	11.42%
Light	42.5	26.97	17.42%
Light	47.5	24.13	9.67%
Light	52.5	22.03	2.96%
Light	57.5	20.68	1.47%
Light	62.5	20.07	0.57%
Light	67.5	19.67	0.38%
U.S. Weighted Average	**32.7**	**36.81**	**100.00%**

Figure 5: Total Refinery CO_2e vs. API Gravity



B.3 Refined Oil End Use Emissions

Step F: Use Table 13, Column 2 to identify the relevant API gravity. Use column 3 in the corresponding row for emissions from combustion and use. Table 14, Column 2 could be used for this step if the producer knows the mix of refined products that will be produced; however, it is highly unlikely that this will be known.

This value is entered into Equation 31 as term $EF_{Oil-End\ Use_{g,t}}$.

Table 13: Petroleum Product End Use GHG Emissions by API Crude Type

1. CLASSIFICATION	2. AVERAGE API GRAVITY OF CRUDE	3. COMBUSTION & USE CO_2e KG/BBL (BEFORE BLENDING, OXYGENATES)[72]	4. COMBUSTION & USE CO_2e KG/BBL (AFTER BLENDING, OXYGENATES)	5. CRUDE INPUTS BY CATEGORY AS % OF ALL U.S. CRUDE INPUTS
Extra Heavy	5.5	437	412	0.22%
Heavy	12.5	420	397	7.15%
Heavy	17.5	408	387	10.30%
Heavy	22.5	399	379	10.14%
Medium	27.5	391	372	15.41%
Medium	32.5	384	367	12.91%
Light	37.5	379	362	11.42%
Light	42.5	369	354	17.42%
Light	47.5	354	341	9.67%
Light	52.5	347	334	2.96%
Light	57.5	332	322	1.47%
Light	62.5	318	310	0.57%
Light	67.5	303	297	0.38%
U.S. Weighted Average	**32.7**	**385**	**367**	**100.00%**

[72] Values are based on carbon content of crude oils and energy used in the refining process. The third column represents the CO_2 in the refinery outputs before blending (with, for example, oxygenates, biofuels, butanes, and imported blendstocks). The fourth column includes the effects of such blending agents.

Table 14: Petroleum Product End Use GHG Emissions, Specified by Individual Product

1. PETROLEUM PRODUCT	2. GREET COMBUSTION GHG CO_2e (KG/BBL)	3. GREET COMBUSTION GHG CO_2e (KG/MMBtu)	4. MMB/YEAR REFINERY OUTPUT	5. COMBUSTION CO_2e 10^6 MT PER YEAR
Propane	213	63.1	435	92.6
Motor Gasoline	356	70.5	3,516	1,251.9
Aviation Gasoline	351	69.5	4	1.5
Jet Fuel	411	72.5	562	231.0
Kerosene	428	75.5	4	1.6
Distillate Fuel Oil	428	74.2	1,830	783.9
Residual Fuel Oil	474	75.4	119	56.1
Petrochemical Feedstock	159	29.2	109	17.3
Naphthas Solvents	358	68.3	12	4.4
Lubricants	226	37.3	61	13.8
Waxes	413	74.5	2	0.7
Asphalt & Road Oil	-	-	118	-
Petroleum Coke	629	102.7	306	192.3
Still Gas	293	46.6	241	70.6
Other Products	354	61.0	32	11.3
Average weighted by U.S. refinery output	**371**	**69.7**	**7,350**	**2,729**
Weighted by U.S. refinery output minus still gas and petroleum coke	**363**	**68.9**	**6,803**	**2,466**

Note: Average for the years 2018 to 2020. The weighted average values represent the mix of U.S. refinery output and not the mix of U.S. domestic consumption.

B.4 Example Produced Oil Emission Factor Calculation

Table 15: Calculating Emission Factors for Permian Basin Field, API Gravity 37.5°, Onshore Southwest NEMS Region

STEP	SUPPLY CHAIN STEP	CO_2e KG/BBL
A	Transport from field to refinery (default from Table 8 for the Southwest region)	2.38
B	Transport of crude oil to foreign refineries (national default from Table 9)	2.21
C	Transport of refined product from refinery to wholesale terminals (Table 10)	4.35
D	Transport of refined product exports (Table 11)	1.51
	The values from Steps A through D are added together and entered into Equation 31 as term $EF_{Oil-Transpo_t}$.	10.45
E	Refining emissions (Table 12). This value is entered into Equation 31 as term $EF_{Oil-Refining_t}$	30.57
F	Product combustion/use (Table 13). This value is entered into Equation 31 as term $EF_{Oil-End\ Use_t}$	379

NOTE: Instructions for using tables are indicated by Steps A to F above. All heat contents in this and other tables are in units of higher heating value (HHV). Carbon dioxide equivalent (CO_2e) includes N_2O and CH_4. Diesel refers to low sulfur No. 2 fuel oil or diesel fuel.

B.5 Alternative Tables for Use in Calculating Produced Oil Emission Factors

Table 16 shall be used as a substitute for Table 8 through Table 11 if a producer knows the specific transportation modes and distances for crude oil or products.

Table 16: Total GHG Emissions from Transport of Petroleum Products using Various Transportation Modes

1. MODE	2. ENERGY SOURCE	3. ENERGY INPUT (BTU PER METRIC TON-MILE)	4. LCA GHG EMISSION FACTOR FOR FUEL (KG/MWH)	5. LCA GHG EMISSION FACTOR FOR FUEL (KG/MMBTU)	6. ENERGY-RELATED GHG EMISSIONS (GRAMS CO_2e/ METRIC TON-MILE)	7. EMBODIED GHG EMISSIONS (GRAMS CO_2e / METRIC TON -MILE)	8. TOTAL GHG EMISSIONS (GRAMS CO_2e / METRIC TON-MILE)
Truck	diesel	1,771.3	-	91.6	162.2	1.10	163.3
Railway	diesel	601.9	-	91.6	55.1	1.20	56.3
Pipeline	diesel	300.0	-	91.6	27.5	6.95	34.4
Pipeline	natural gas	300.0	-	63.9	19.2	6.95	26.1
Pipeline	electricity (U.S. average)	110.5	373.1	109.4	12.1	6.95	19.0
	electricity (Onshore East)	110.5	405.0	118.7	13.1	6.95	20.1
	electricity (Onshore Gulf Coast)	110.5	364.7	106.9	11.8	6.95	18.8
	electricity (Midcontinent)	110.5	475.5	139.4	15.4	6.95	22.4
	electricity (Southwest)	110.5	401.2	117.6	13.0	6.95	19.9
	electricity (Rocky Mountain)	110.5	508.5	149.0	16.5	6.95	23.4
	electricity (Northern Great Plains)	110.5	482.1	141.3	15.6	6.95	22.6
	electricity (West Coast)	110.5	193.0	56.6	6.3	6.95	13.2

1. MODE	2. ENERGY SOURCE	3. ENERGY INPUT (BTU PER METRIC TON-MILE)	4. LCA GHG EMISSION FACTOR FOR FUEL (KG/MWH)	5. LCA GHG EMISSION FACTOR FOR FUEL (KG/MMBTU)	6. ENERGY-RELATED GHG EMISSIONS (GRAMS CO_2e/ METRIC TON-MILE)	7. EMBODIED GHG EMISSIONS (GRAMS CO_2e / METRIC TON -MILE)	8. TOTAL GHG EMISSIONS (GRAMS CO_2e / METRIC TON-MILE)
	electricity (GOM State)	110.5	345.5	101.3	11.2	6.95	18.1
	electricity (GOM Fed Shallow)	110.5	345.5	101.3	11.2	6.95	18.1
	electricity (GOM Fed Deep)	110.5	345.5	101.3	11.2	6.95	18.1
	electricity (Pac Off State)	110.5	205.5	60.2	6.7	6.95	13.6
	electricity (Pac Off Federal)	110.5	205.5	60.2	6.7	6.95	13.6
	electricity (AK Onshore)	110.5	438.2	128.4	14.2	6.95	21.1
	electricity (AK State Offshore)	110.5	438.2	128.4	14.2	6.95	21.1
	electricity (AK Federal Offshore)	110.5	438.2	128.4	14.2	6.95	21.1
	electricity (Nonproducing)	110.5	284.4	83.3	9.2	6.95	16.2
Pipeline	electricity (oil-fired)	110.5	-	268.5	29.7	6.95	36.6
Pipeline	electricity (gas-fired)	110.5	-	187.2	20.7	6.95	27.6
Pipeline	electricity (coal-fired)	110.5	-	303.9	33.6	6.95	40.5
Barge	diesel	614.5	-	91.6	56.3	0.90	57.2
Ocean Tanker	diesel	80.0	-	91.6	7.3	0.40	7.7
Ocean Tanker	bunker fuel	80.0	-	93.6	7.5	0.40	7.9

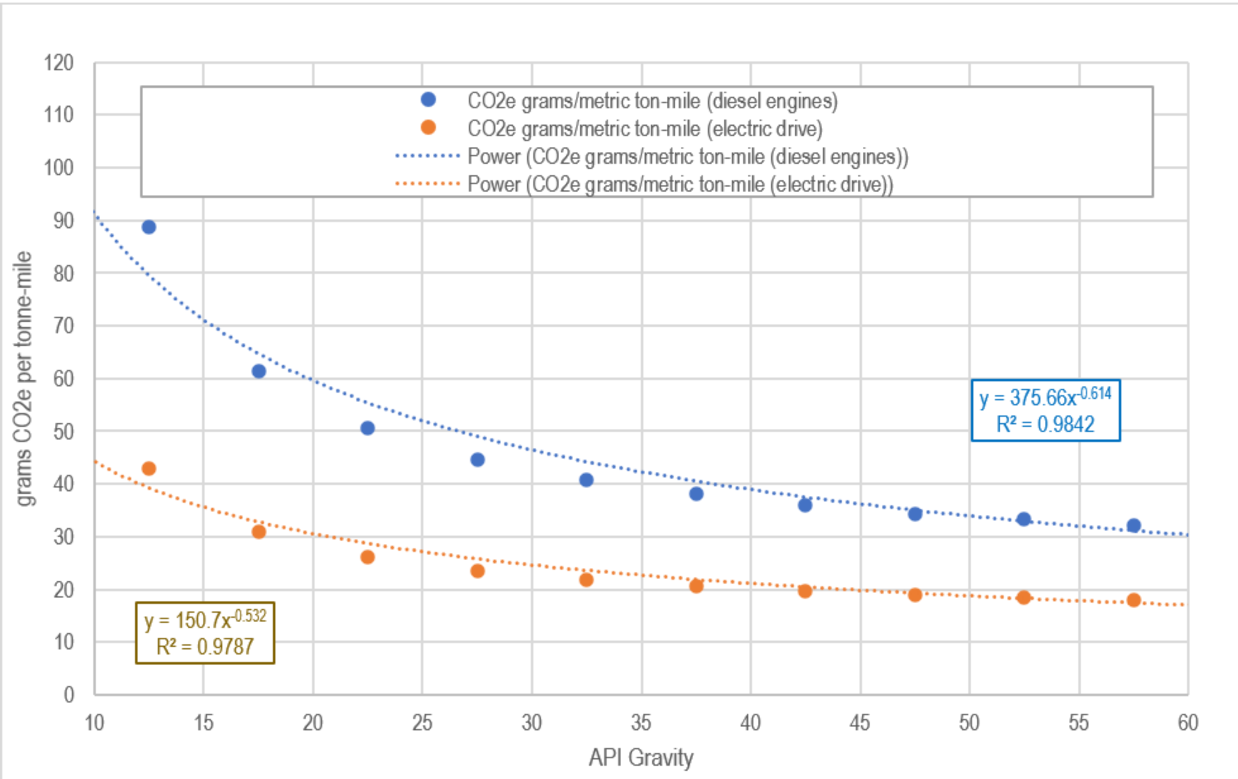
Note: Pipeline electricity emissions are from eGRID 2020 and are calculated by NEMS regions. If the region isn't known, the U.S. average shall be used. Electricity LCA for U.S. average is assumed to be 373 kg/MWh. The heat rate for oil and coal are assumed to be 10,000 Btu/kWh. All Btu measurements represent higher heating values.

Table 17 and Figure 6 are provided as backup data for some of the other tables presented here that are used for **Step B** or **Step E**. You do not need to use this table or chart to do the required calculations.

Table 17: GHG Emissions for Pipeline Transport of Crude Oils & Petroleum Products

1. CRUDE CLASSI-FICATION	2. AVERAGE API GRAVITY	3. PIPELINE PRIME MOVER WORK (BTU/METRIC TON-MILE)	4. FOSSIL PRIME MOVER ENERGY INPUT (BTU/METRIC TON-MILE)	5. ELECTRIC PRIME MOVER ENERGY INPUT (BTU/METRIC TON-MILE)	6. CO_2e GRAMS/ METRIC TON-MILE (DIESEL ENGINES)	7. CO_2e GRAMS/ METRIC TON-MILE (ELECTRIC DRIVE)	8. BBL/ METRIC TON	9. ENERGY-RELATED CO_2e GRAMS/ BBL-MILE (DIESEL ENGINES)	10. ENERGY-RELATED CO_2e GRAMS/ BBL-MILE (ELECTRIC DRIVE)
Extra Heavy	5.5	514	1,468	541	141.4	66.1	6.09	23.2	10.9
Heavy	12.5	312	892	329	88.6	42.9	6.40	13.8	6.7
Heavy	17.5	208	596	219	61.4	30.9	6.62	9.3	4.7
Heavy	22.5	167	478	176	50.7	26.2	6.85	7.4	3.8
Medium	27.5	144	413	152	44.7	23.6	7.07	6.3	3.3
Medium	32.5	130	370	136	40.8	21.9	7.29	5.6	3.0
Light	37.5	119	341	126	38.1	20.7	7.51	5.1	2.8
Light	42.5	111	317	117	36.0	19.7	7.73	4.7	2.6
Light	47.5	105	300	111	34.4	19.0	7.96	4.3	2.4
Light	52.5	101	287	106	33.2	18.5	8.18	4.1	2.3
Light	57.5	97	276	102	32.2	18.1	8.40	3.8	2.2
Light	62.5	97	276	102	32.2	18.1	8.62	3.7	2.1
Light	67.5	97	276	102	32.2	18.1	8.85	3.6	2.0
Products: Gasoline		**105**	**300**	**111**	**34.4**	**19.0**	**8.40**	**4.1**	**2.3**
Products: Diesel		**105**	**300**	**111**	**34.4**	**19.0**	**7.44**	**4.6**	**2.6**

Figure 6: Pipeline GHG Emissions Relative to API Gravity



Appendix C: Alternative Quantification Methods

This appendix provides information on alternative quantification methods that may be applied to perform CO_2 mass balance calculations, to calculate GHG emissions from electricity usage, to calculate GHG emissions from stationary combustion from fuel use. All of these methods have the same level of accuracy as the other methods listed in Section 6 of the Methodology.

C.1 Alternative Flow Equation

The equations presented in this methodology rely on continuous measurement of CO_2 at various stages of the CCS project. These flow measurements may be performed using either volumetric flow meters or mass flow meters. All of the calculations in the main section of this document rely on volumetric measurements, but a mass-based measurement may alternatively be used.

For a mass (coriolis or thermal mass) flow meter, the total mass of CO_2 must be calculated in metric tons by multiplying the metered mass flow by the concentration in the flow, according to the following equations. If metering pure (100%) CO_2, CH_4, or other fuel or product, the concentration is not needed. If metering a gas mixture, the concentration or composition is needed to determine the mass.

Equation 44: Alternative Methodology to Calculate Mass of CO_2 (Mass Flow Meter)

$$CO_{2_t} = \sum_f Q_{f,t} \times C_{CO_{2_{f,t}}}$$

WHERE

CO_{2_t}	Total mass of CO_2 measured by all flow meters in the relevant project segment (e.g., capture, transport, storage) in Reporting Period **t** ($MTCO_2$)
$Q_{f,t}$	Mass flow through meter **f** in Reporting Period **t** (MT).
$C_{CO_{2_{f,t}}}$	CO_2 concentration measurement in flow meter **f** in Reporting Period **t** (%CO_2 by mass, expressed as a decimal).

C.2 Alternative Electricity Emissions Equation

The following equation can be used to quantify GHG emissions from the use of grid electricity at any segment of a CCS project as a contingency if a distinct electricity meter reading is unavailable (e.g., other loads that are unrelated to the CCS project are tied into the same meter). Can be used in lieu of the electricity portion of Equation 11.

Equation 45: Alternative Methodology to Calculate Project Emissions from Electricity Used to Operate Equipment Associated with the CCS Project

$$\mathbf{PE_{Alt-Elec_t}} = \sum_{\mathbf{i}} (\mathbf{Electrical\ Rating_{i,t}} \times \mathbf{Hours_{i,t}} \times \mathbf{Load_{i,t}}) \times \mathbf{EF_{Electricity_t}}$$

WHERE

$PE_{Alt\text{-}Elec_t}$	Project emissions from electricity used to operate equipment in Reporting Period **t** ($MTCO_2e$).
$Electrical\ Rating_{i,t}$	Electrical rating in MW for equipment **i** used in the relevant project segment (e.g., capture, processing & compression; transport; injection, storage, monitoring & hydrocarbon production and onsite processing) in Reporting Period **t** (MW).
$Hours_{i,t}$	Operating hours for each piece of equipment that uses electricity or, if insufficient records are available, assumed to be equal to the number of hours in Reporting Period **t** for conservativeness (hours).
$Load_{i,t}$	Percent loading of each piece of equipment in Reporting Period **t** (unitless). Estimated (with estimate reasoning documented) or assumed to be 100%.
$EF_{Electricity_t}$	Emission factor for electricity generation in the relevant region in Reporting Period **t** ($MTCO_2e/MWh$).

C.3 Correcting Gas Volumes to Standard Temperature and Pressure

Equation 46: Converting Gas Volumes from Measured Values to Standard Temperature and Pressure (1 atm, 60 °F)

$$\mathbf{Vol._{STP}} = \frac{\mathbf{Vol._{Measured}} \times \mathbf{Pressure_{Measured}} \times \mathbf{288.75\ K}}{\mathbf{Temp_{Measured}} \times \mathbf{1\ atm}}$$

WHERE

$Vol._{STP}$	Volume of gas corrected to a standard pressure of 1 atm and a standard temperature of 60 °F (m^3).
$Vol._{Measured}$	Measured volume of gas (m^3).
$Pressure_{Measured}$	Measured pressure of gas (atm).
288.75 Kelvin	Temperature in Kelvin equal to 60 °F.
$Temp_{Measured}$	Measured temperature in Kelvin (K). See Equation 47 for conversion of °F and °C to Kelvin.

Equation 47: Converting Common Temperatures to Kelvin

$$\text{Kelvin} = \frac{°F - 32}{1.8} + 273.15$$

or

$$\text{Kelvin} = °C + 273.15$$

WHERE

Kelvin	Temperature in Kelvin (K).
°F	Temperature in degrees Fahrenheit (°F).
°C	Temperature in degrees Celsius (°C).

C.4 Fugitive Emissions Sources

Table 18 provides information about potential fugitive emissions sources.

Table 18: Surface Components as Potential Emissions Sources[73]

EMISSIONS SOURCE	ENGINEERING ESTIMATE	EQUIPMENT COUNT & POPULATION FACTOR	REFERENCE IN U.S. EPA GHG REPORTING PROGRAM SUBPART W
NATURAL GAS PNEUMATIC HIGH BLEED DEVICE VENTING		X	Eq. W-1
NATURAL GAS PNEUMATIC HIGH LOW DEVICE VENTING		X	Eq. W-1
NATURAL GAS PNEUMATIC INTERMITTENT BLEED DEVICE VENTING		X	Eq. W-1

[73] (U.S. EPA, 2010b)

EMISSIONS SOURCE	ENGINEERING ESTIMATE	EQUIPMENT COUNT & POPULATION FACTOR	REFERENCE IN U.S. EPA GHG REPORTING PROGRAM SUBPART W
NATURAL GAS DRIVEN PNEUMATIC PUMP VENTING		X	Eq. W-1
RECIPROCATING COMPRESSOR ROD AND PACKING VENTING		X	Eq. W-26 and W-27
EOR INJECTION PUMP		X	
EOR INJECTION PUMP BLOWDOWN	X		Eq. W-37
CENTRIFUGAL COMPRESSOR WET SEAL OIL DEGASSING VENTING		X	Eq. W-22 through W-25
OTHER EQUIPMENT LEAKS[74]		X	Eq. W-31

[74] Valves, connectors, open-ended lines, pressure relief valves

Appendix D: Sustainable Biomass

Biomass can play a key role in climate change mitigation through its use in bioenergy and biomaterials and must be managed responsibly to avoid conflicts with ecosystem functions, food security, and human needs (IPCC, 2012; U.S. EPA, 2014). Unsustainable biomass sourcing has the potential to contribute to climate change and environmental degradation (IPCC, 2012). Biomass-based technologies do not inherently deliver climate benefits, necessitating frameworks that ensure positive environmental, social, and climate outcomes.

The following criteria provide practical, enforceable guidelines with the goal of ensuring that biomass fuels and feedstocks contribute positively to environmental, social, and climate outcomes. These criteria are aligned with major sustainability frameworks and support the generation of carbon reduction or removal credits (IPCC, 2012).

To qualify as sustainable biomass, ACR requires that biomass used as fuel or feedstock in a CCS project meet the following requirements:

I. Biomass shall be derived from forestry, agriculture, or waste;
II. Biomass shall comes from sources located within the U.S. and Canada;
III. Biomass must not come from forest conversion, including natural forests converted to monocultural plantations, agriculture or non-forest land uses;
IV. Biomass must not come from primary forest, intact forest landscapes, old-growth forest or High Conservation Value forests;
V. Biomass must come from sources that do not harm workers, Indigenous People or local communities; and
VI. Biomass must not displace other forest or agricultural products with a greater economic value. In particular, biomass must not come from whole trees or crops grown for the express purpose of generating electricity.

To comply with these requirements and be eligible to generate credits, ACR requires that projects verify the following, as relevant:

VII. If the biomass is from waste that is not derived from forestry or agricultural sources, verify the source of the waste (including country of origin), date (or range) of delivery, and name of entity delivering waste and confirm that the volumes of biomass used in the Project are feasible for the specific waste source. Waste includes material that would otherwise have been discarded if the Project did not exist.

VIII. If the biomass is from forest management, verify the following:

A. The biomass maintains Forest Stewardship Council (FSC) certification (FSC MIX or FSC 100%; FSC, n.d) at the entry point to the project, meaning that all organizations along the value chain maintain FSC Chain-of-Custody certification and the source forest maintains FSC Forest Management Certification.

B. Sustainable Forestry Initiative Certified Chain of Custody (SFI, n.d.) may be substituted for FSC if the Project Proponent provides, in addition to the certification itself, additional assurance that the requirements above have been met.

C. Forest biomass must maintain Roundtable on Sustainable Biomaterials (RSB) certification using the RSB Standard for Advanced Fuels (RSB, 2023, or more recent approved version).

D. ACR may consider alternative certifications that include independent third-party verification that the requirements above have been achieved. ACR reserves the right to approve or reject these alternatives.

IX. If the biomass is from agriculture, verify that the biomass maintains RSB certification using the RSB Standard for Advanced Fuels (RSB, 2023, or more recent approved version).

Appendix E: Emission Factor Guidance

This appendix prescribes the mandatory procedures for selecting, documenting, and applying emission factors and emissions-intensity metrics within all eligible CCS projects. It supports the quantification outlined in Sections 6.1 and 6.2 by ensuring that GHG calculations are transparent, conservative, and verifiable. Unless otherwise noted, the guidance herein applies to all sources identified in Sections 6.1 and 6.2 of the Methodology.

E.1 General Requirements for Emission Factor Selection

All emission factors must satisfy the following criteria:

I. Emission factors shall be appropriately applied to the emission source.
II. Emission factors shall utilize the appropriate basis of measurement.
III. Emission factors shall account for uncertainty, where applicable.
IV. The Project Proponent shall record units, data source of emission factor, publication year, and all conversion steps.
V. Emission factors must be reviewed each Reporting Period. Updates are required when more current or applicable emission factors or other data becomes available.
VI. Emission factors must correspond to the time period in which the associated activity occurred, including generation, combustion, procurement, installation, or manufacturing. If emission factor data are unavailable for the calendar year in which the project activity occurred, the Project Proponent shall use data from the year closest to the Reporting Period year(s). If two separate data years are equally close in time, the Project Proponent shall use the more conservative (i.e., highest) emission factor.
VII. Emission factors must reflect the regional context of production or activity. If location-specific data is unavailable, appropriate adjustments must be applied and justified.

E.2 Emission Factor Sources

Table 19 provides the hierarchy for each emission factor source category. Tier 1 emission factors should be applied unless demonstrably unavailable. Tier 2 emission factors should be applied only when Tier 1 data are absent or inapplicable; the Project Proponent must provide justification. Preference shall be given to data sources that provide third-party verification and uncertainty ranges. Where uncertainty is >5%, a sensitivity analysis shall be conducted to assess the emission factor's impact on reported emissions.

Table 19. Hierarchy of Emission Factors by Source Category

SOURCE CATEGORY	TIER 1 (PREFERRED)	TIER 2 (ALTERNATIVE)
ELECTRICITY (U.S.)	U.S. EPA eGRID – balancing authority area (BAA)[75] *or* power purchase agreement[76]	U.S. EPA eGRID subregion[77]
ELECTRICITY (CANADA)	ECCC emission factors and reference values[78] *or* power purchase agreement[79]	More recent provincial regulatory emission factor with citation

[75] https://www.epa.gov/egrid

[76] Project Proponent shall document the reasoning for the choice of that emission factor and provide a copy of the power purchase agreement.

[77] https://www.epa.gov/egrid

[78] Use the most recent or Reporting Period- or year-appropriate published ECCC emission factors (e.g., from https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system/federal-greenhouse-gas-offset-system/emission-factors-reference-values.html).

[79] Project Proponent shall document the reasoning for the choice of that emission factor and provide a copy of the power purchase agreement.

SOURCE CATEGORY	TIER 1 (PREFERRED)	TIER 2 (ALTERNATIVE)
STATIONARY COMBUSTION[80] (U.S. & CANADA)[81]	U.S. EPA 40 CFR Part 98, Subpart C[82] or ECCC emission factors and reference values[83] or WebFIRE Database[84]	IPCC Emission Factor Database[85]
MOBILE TRANSPORT (U.S.)	EPA MOVES[86]	R&D GREET[87]
MOBILE TRANSPORT (CANADA)	EPA MOVES[88] with Canada Adjustment or WebFIRE Database[89]	IPCC Emission Factor Database[90]
FUGITIVE EMISSIONS (U.S. & CANADA)	U.S. EPA 40 CFR 98 Subpart W emission factors (Tables W-1A, W-3 through W-6)[91] Factors must be matched to component type, gas type, and regional context (e.g., eastern vs. western U.S.)[92]	IPCC Emission Factor Database[93]

[80] Everywhere that stationary combustion is referred to in Methodology equations it should be interpreted as "stationary combustion or other energy production process (e.g., redox reaction in a fuel)" and most references to "fuel" can be read as "fuel or other energy-producing input." Emission factors for non-combustion energy production shall be derived from the same sources as those listed for stationary combustion (e.g. U.S. EPA for U.S. projects, ECCC for Canadian CCS projects).

[81] This includes any equipment that is permitted as a mobile source but is used in a stationary manner (e.g., diesel engine on a flatbed truck).

[82] 40 CFR Part 98, Subpart C establishes monitoring and reporting requirements for CO_2, CH_4, and N_2O emissions from general stationary fuel combustion sources under U.S. EPA's Greenhouse Gas Reporting Program (U.S. EPA, 2009).

[83] Use the most recent or Reporting Period- or year-appropriate published ECCC emission factors (e.g., from https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system/federal-greenhouse-gas-offset-system/emission-factors-reference-values.html).

[84] https://cfpub.epa.gov/webfire/index.cfm?action=fire.main

[85] https://www.ipcc-nggip.iges.or.jp/EFDB/main.php

[86] https://www.epa.gov/moves

[87] (Argonne National Laboratory, 2025)

[88] https://www.epa.gov/moves

[89] https://cfpub.epa.gov/webfire/index.cfm?action=fire.main

[90] https://www.ipcc-nggip.iges.or.jp/EFDB/main.php

[91] (U.S. EPA, 2025a)

[92] Canadian projects shall use the emission factor from the U.S. region most similar to the Canadian project region and document the reasoning for the choice of that emission factor.

[93] https://www.ipcc-nggip.iges.or.jp/EFDB/main.php

SOURCE CATEGORY	TIER 1 (PREFERRED)	TIER 2 (ALTERNATIVE)
CONSTRUCTION MATERIAL PRODUCTION (U.S. & CANADA)	Refer to Table 6 for cement and asphalt. For steel products, utilize World Steel Association 2022 lifecycle assessment (LCA) eco-profiles for construction materials[94] for the following products: • Cold rolled coil[95] • Electrogalvanized coil[96] • Electrolytic chromium coasted steel[97] • Engineering steel[98] • Finished cold rolled coil[99] • Hot-dip galvanized coil[100] • Hot rolled coil[101] • Organic coated steel[102] • Pickled hot rolled coil[103] • Plate[104] • Rebar[105] • Seamless pipe[106] • Sections[107] • Tinplate[108]	

[94] All eco-profiles are available at https://worldsteel.org/wider-sustainability/life-cycle-thinking/lca-eco-profiles-2022/.

[95] (World Steel Association, 2023a)

[96] (World Steel Association, 2023b)

[97] (World Steel Association, 2023c)

[98] (World Steel Association, 2023d)

[99] (World Steel Association, 2023e)

[100] (World Steel Association, 2023f)

[101] (World Steel Association, 2023g)

[102] (World Steel Association, 2023h)

[103] (World Steel Association, 2023i)

[104] (World Steel Association, 2023j)

[105] (World Steel Association, 2023k)

[106] (World Steel Association, 2023l)

[107] (World Steel Association, 2023m)

[108] (World Steel Association, 2023n)

SOURCE CATEGORY	TIER 1 (PREFERRED)	TIER 2 (ALTERNATIVE)
	• UO pipe[109] • Welded pipe[110] • Wire rod[111] Unless the Project Proponent can demonstrate that the steel construction material listed above will be recycled at the end of the project, the Project Proponent shall use World Steel's "Climate Change – total" "cradle-to-gate results" GHG emissions intensity factor without any deductions for "benefit of recycling results." If there is no World Steel Association LCA is available for the steel product, the following default emission factor shall be used: 2.18 $MTCO_2e$/metric tons steel.[112]	
CONSTRUCTION MATERIAL PRODUCTION—PIPELINES & PIPELINE COMPRESSORS (U.S. & CANADA)	Environmental Product Declaration (EPD) consistent with ISO (2006), if available. If no EPD is available, use the mass-based value listed in "Steel Construction Material Production (U.S. & Canada)" immediately above for a specified product (especially engineering steel, seamless pipe, UO pipe, and welded pipe) or for non-specified steel products using the default emission factor of 2.18 $MTCO_2e$/metric tons steel.	
PRODUCED OIL (CO_2-EOR ONLY; U.S.)	Refer to Appendix B.	
PRODUCED ASSOCIATED GAS (CO_2-EOR ONLY; U.S.)	R&D GREET 2025[113] (or most recently published version) using outputs from the gas processing, transport and distribution, and fuel use stages; and using regionally appropriate assumptions about the pathway that the associated gas will take once it leaves the oil production and CO_2 storage site.	
PRODUCED OIL & ASSOCIATED GAS (CO_2-EOR ONLY; CANADA)	R&D GREET 2025 (or most recently published version) using outputs from the oil refining, gas processing, transport and distribution, and fuel use stages; and using regionally appropriate assumptions about the pathway that the produced oil and associated gas will take once it leaves the oil production and CO_2 storage site.	

[109] (World Steel Association, 2023o)

[110] (World Steel Association, 2023p)

[111] (World Steel Association, 2023q)

[112] Global GHG emissions intensity factor for steel products from World Steel Association (2026).

[113] (Argonne National Laboratory, 2025)

E.2.1 ADDITIONAL DETAILS REGARDING ELECTRICITY EMISSION FACTORS

Projects may apply a custom emission factor only if they demonstrate the following

I. A power purchase agreement (PPA) for the electricity resource with the emission factor being claimed.

II. For zero- (or near-zero) GHG emissions electricity sources, the PPA must be for electricity from a newly constructed electricity generator.

III. The Project Proponent or the owner or operator of the CCS project segment for which the custom emission factor is being claimed must be named on the PPA.

IV. For renewable resources, the renewable energy credits associated with the energy used for the CCS project must be retired and evidence of retirement provided.

E.2.2 ADDITIONAL DETAILS REGARDING TRANSPORT EMISSION FACTORS

I. Where applicable, and especially for U.S. EPA MOVES data, emission factors appropriate to vehicle class and model year shall be utilized.[114]

II. Evidence must be provided showing the distance of every trip from origin to the next destination. When no onwards journey information is available, the fully loaded round trip must be assumed in calculations.

III. Distance traveled can be determined by one of the following methods:
   A. Recording of vehicle odometer reading before and after completion of trip,
   B. Recording of travel distance by vehicle fleet management system online mapping of route traveled using common mapping platforms (e.g., Google Maps) and exact start and end trip locations, or
   C. Other justifiable methods that account for actual operating time or fuel consumption for each equipment or vehicle type.

IV. Documentation of equipment or material weight by weight scale, equipment specification sheet, bill of lading, or similar transportation documentation indicating load type/contents, quantity, and pickup and delivery location.

V. Use the emission factor for the corresponding mode of transport wherever possible.

[114] https://www.epa.gov/moves

VI. When multiple transport modes are utilized and the distance traveled for each mode is not available, use the highest-emitting mode (truck has higher emissions than ship, which has higher emissions than rail, which has higher emissions than pipeline). Document the rationale.

The Project Proponent shall document the following information for each emission factor used in the CCS project that is not explicitly outlined in this Methodology:

VII. The reference for the emission factor;
VIII. Geographic and temporal applicability;
IX. GWP used in reference;
X. Material, technology, equipment, and fuel type (as applicable);
XI. Emission factor as reported in the source material, including units;
XII. Conversion of the emission factor to the form used in Methodology equations, showing all work;
XIII. Final emission factor value, including units;
XIV. GWP value (e.g., AR4 GWP100) used by the emission source reference;
XV. Heating value basis; and
XVI. Uncertainty.

Appendix F: Missing Data Substitution Procedures

ACR expects that CCS projects will have continuous, uninterrupted data for the entire Reporting Period. However, ACR recognizes that unexpected events or occurrences may result in brief data gaps. This Appendix provides a quantification methodology to be applied to the calculation of metered data when data integrity has been compromised due to missing data points. The data substitution procedures found in Table 20 are applicable to the monitored parameters outlined in Section 7.2 that are used to quantify emission removals such as gas flow metering and CO_2 concentration. Data substitution is not allowed for equipment that monitors the proper functioning of capture and injection equipment.

This methodology may be used for missing temperature and pressure data used to adjust flow rates to standard conditions. It may be used only for flow and CO_2 concentration data gaps that are discrete, limited, non-chronic, and due to unforeseen circumstances. Substitution may only occur when two other monitored parameters corroborate proper functioning of the device from which data are missing and operation of that device within normal ranges.

If corroborating parameters fail to demonstrate any of the requirements above, no substitution may be employed. If the requirements above can be met, the substitution methodology outlined in Table 20 may be applied:

Table 20: Data Substitution Methodology

PERIOD OF MISSING DATA	SUBSTITUTION METHODOLOGY
LESS THAN SIX HOURS	Use the average of the four hours of normal operation immediately before and following the outage, or a more conservative value.
SIX TO 24 HOURS	Use the 90% upper or lower confidence limit (whichever is more conservative) of the 24 hours of normal operation prior to and after the outage, or a more conservative value.
ONE TO SEVEN DAYS	Use the 95% upper or lower confidence limit (whichever is more conservative) of the 72 hours of normal operation prior to and after the outage, or a more conservative value.
GREATER THAN ONE WEEK	No data may be substituted, and no credits may be generated