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

CARBON CAPTURE AND STORAGE PROJECTS

VERSION 2.0

Month Year

ACR
AT WINROCK INTERNATIONAL

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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.

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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 captured from underground sources to utilize a process called 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).

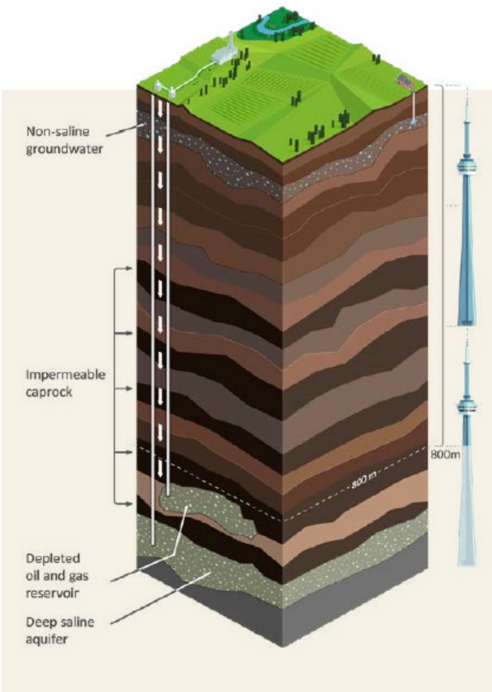
Starting in the early 2000s, increased attention to climate change and the need to decrease GHG emissions prompted broader applications of the underground injection and storage technology to permanently store CO_2 underground. This included identifying large sources of fuel-derived CO_2 such as power generation, cement production, [1] steel manufacturing, and chemical processing; and developing and refining CO_2 capture methods (Global CCS Institute, 2024b). 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 an impermeable layer (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 can trap

[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.

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: Typical CO_2 Storage Process in a Geologic Storage Reservoir (non-EOR)[4]



Today, CCS is increasingly recognized as a cornerstone of global climate strategy 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 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:

[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)

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

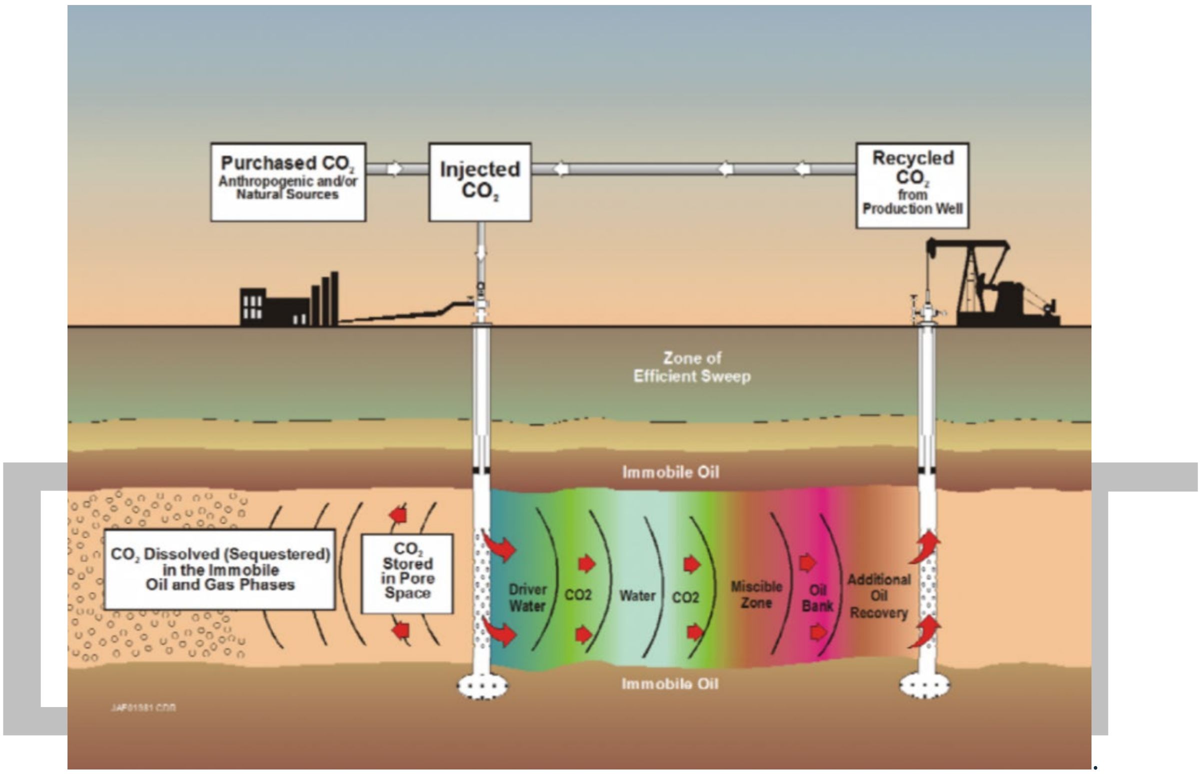
- Capture of carbon dioxide (CO_2) molecules from either
  - Electricity generation or industrial process point source emissions before they enter the atmosphere; or
  - The atmosphere, through carbon dioxide removal (CDR);
- Transport of the captured CO_2; and
- Safe, permanent storage of the CO_2 in 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, 2024a & 2024b). Whichever storage capacity estimate is correct, it is clear that 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 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 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 recompressed 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: 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 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 has no benefit to addressing climate change. 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 emissions reduction strategies (IPCC, 2023).

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

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 conservative business-as-usual release of CO_2 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. For CDR 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 through eligible DAC, BECCS, and BiCRS activities and permanently store it.

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).

Project Proponents must contribute credits to the ACR Reserve Account to mitigate reversal risk during the project term (see Section 9). This includes monitoring during the post-injection period to demonstrate that plume stabilization has been achieved (see Section 7.3.12). Reversals are mitigated thereafter through the filing of a Risk Mitigation Covenant in the jurisdiction's real property records to prevent, provide for the discovery of, and compensate for reversals after the project term (see Section 9.3).

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 all segments of the project (capture, transport, storage).

II. 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.

III. 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.

IV. 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 well under the U.S. Environmental Protection Agency's (EPA's) Underground Injection Control (UIC) Program (U.S. EPA, 2025e). In Canada, wells shall be permitted under federal or provincial regulatory frameworks. Wells shall also meet all requirements outlined in Section 7 of this Methodology. Refer to Appendix E for a list of applicable regulations.

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

VI. Demonstrate clear and uncontested rights to the storage reservoir pore space as described in Section 8.3 and that the Project Proponent has filed a Risk Mitigation Covenant and/or provided an alternative risk mitigation assurance acceptable to ACR as described in Section 9.3.

VII. Demonstrate approval (through legal agreements) from the surface owner(s) for the Project Proponent to access the surface land for the duration of the project term to conduct post-injection monitoring and, if necessary, remediation, as described in Section 8.4.

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

[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.

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

X. 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.

Eligible project activities include the CO_2 capture sources, 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 CAPTURE SOURCES	Capture of CO_2 emissions from electrical power generation and industrial processes, landfills, and 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 CO_2 pools).[8] 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.

[8] 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 CO_2 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 lacks adequate capacity or injectivity for the proposed operation.
- 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 statue, 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. Refer to the tables in Appendix E for a list of regulatory requirements.

If the quantity of CO_2 captured and stored exceeds the requirements imposed by law, regulation, or other legal mandates, then those excess 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 Sections 3.2.2 through .

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;[9] Heirloom Tracy, California;[10] Commerce City DAC Plant, Colorado;[11] and The Dalles by 280Earth, Oregon[12]), and one such facility in Canada (Carbon Engineering, British Columbia) (Direct Air Capture Coalition, 2024). 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, 2024). 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

[9] (Heimdal, 2024)
[10] (Heirloom Carbon Technologies, 2023)
[11] (Global Thermostat, 2023)
[12] (280Earth, n.d.)

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, 2024a; ECCC, 2024), with the total number of facilities which capture CO_2 that is then injected into a geologic storage reservoir (Global CCS Institute, n.d.). 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 [13]	NO. OF FACILITIES WITH CO_2 CAPTURE & STORAGE [14]	PENETRATION OF CO_2 CAPTURE & STORAGE	FACILITY PRIMARY NAICS [15] CODES, REPORTING SECTION, OR OTHER REFERENCE
POWER GENERATION (FOSSIL FUELS)	1,212	0	0%	221112
POWER GENERATION	21	0	0%	221112 & 221117

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

[14] Number of facilities is derived from the Global CCS Institute's CO_2RE Global CCS Facilities Database (Global CCS Institute, n.d.), including only operational facilities and excluding facilities for which the CO2 is used for CO2-EOR.

[15] NAICS = North American Industry Classification System

CO_2 SOURCE FACILITY TYPE	NO. OF FACILITIES [13]	NO. OF FACILITIES WITH CO_2 CAPTURE & STORAGE [14]	PENETRATION OF CO_2 CAPTURE & STORAGE	FACILITY PRIMARY NAICS [15] CODES, REPORTING SECTION, OR OTHER REFERENCE
(BIOGENIC FUELS [16])				
NATURAL GAS PROCESSING	445	5 [17]	0.9%	Subpart W-PROC
PETROLEUM REFINING	130	0	0%	324110
ETHYL ALCOHOL (ETHANOL) MANUFACTURING	165	2	2%	325193
HYDROGEN MANUFACTURING	114	1	0.9%	Subpart Y [18]
NITROGENOUS FERTILIZER MANUFACTURING	32	1	3%	325311
IRON & STEEL MILLS AND FERROALLOY MANUFACTURING	98	1	1%	331110
CEMENT MANUFACTURING	87	0	0%	327310

[16] 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).

[17] 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 (Global CCS Institute, n.d.)

[18] 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 [13]	NO. OF FACILITIES WITH CO_2 CAPTURE & STORAGE [14]	PENETRATION OF CO_2 CAPTURE & STORAGE	FACILITY PRIMARY NAICS [15] CODES, REPORTING SECTION, OR OTHER REFERENCE
OTHER INDUSTRIAL SOURCES	--	0	0%	--
LANDFILLS [19]	2,639	0	0%	(U.S. EPA, 2024b)
LIVESTOCK AND WASTEWATER TREATMENT ANAEROBIC DIGESTION	>1,600 [20]	0	0%	(U.S. EPA, 2024c, U.S. EPA, 2025a)
TOTAL	**>6,543**	**10**	**0.2%**	

[19] Includes only municipal solid waste landfills.

[20] 400 manure-based anaerobic digestion facilities as of June 2024 (U.S. EPA, 2024c) and anaerobic digesters at over 1,200 Water Resource Recovery Facilities (U.S. EPA, 2025a).

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 [21]	NO. OF FACILITIES WITH CO_2 CAPTURE & STORAGE [22]	PENETRATION OF CO_2 CAPTURE & STORAGE	FACILITY PRIMARY NAICS [23] CODES OR OTHER REFERENCE
POWER GENERATION (FOSSIL FUELS)	108	1 [24]	0.9%	221112
POWER GENERATION (BIOGENIC FUELS)	7	0	0%	221119 [25]
NATURAL GAS PROCESSING	718	0	0.1%	(Government of Canada, 2021)
PETROLEUM REFINING	17	0	0%	324110
ETHANOL MANUFACTURING	8	0	0%	325190 [26]
HYDROGEN MANUFACTURING	8	1 [27]	13%	325120 [28]

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

[22] Number of facilities is derived from Global CCS Institute (n.d.), including only operational facilities and excluding facilities for which the CO_2 is used for CO_2-EOR.

[23] NAICS = North American Industry Classification System

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

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

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

[27] Quest hydrogen plant in Alberta.

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

CO_2 SOURCE FACILITY TYPE	NO. OF FACILITIES [21]	NO. OF FACILITIES WITH CO_2 CAPTURE & STORAGE [22]	PENETRATION OF CO_2 CAPTURE & STORAGE	FACILITY PRIMARY NAICS [23] 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 [29]	>3,000	0	0%	(ECCC, 2022)
LIVESTOCK AND WASTEWATER TREATMENT ANAEROBIC DIGESTION	61	0	0%	(CBA & AAFC, 2018)
TOTAL	**>3,969**	**2**	**0.1%**	

[29] Includes only municipal solid waste landfills.

3.2.3 NON-CDR CO_2 SOURCES FOR EOR-CCS

The use of non-CDR CO_2 sources of anthropogenic CO_2 [30] 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-CDR 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 [31]	**2087**	**744**	**35%**
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%

[30] For the sake of this performance standard, "anthropogenic CO_2" means CO_2 that comes from a non-geologic point source of CO_2 and includes CO_2 captured from point sources that are combusting (or otherwise utilizing) biogenic fuels.

[31] (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 [32]	**3.2**	**3.2**	**100%**

3.2.4 CDR 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 [33] 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. [34] 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 uses sustainable biomass and passes the regulatory surplus test.

3.3 Three-Pronged Additionality Test

Projects that do not qualify under the performance standard (i.e., non-CDR 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

[32] (ECCC, 2025)

[33] 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.

[34] 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 (Global CCS Institute, n.d.). All of these facilities use fossil fuels.

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 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 hydrocarbons 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.

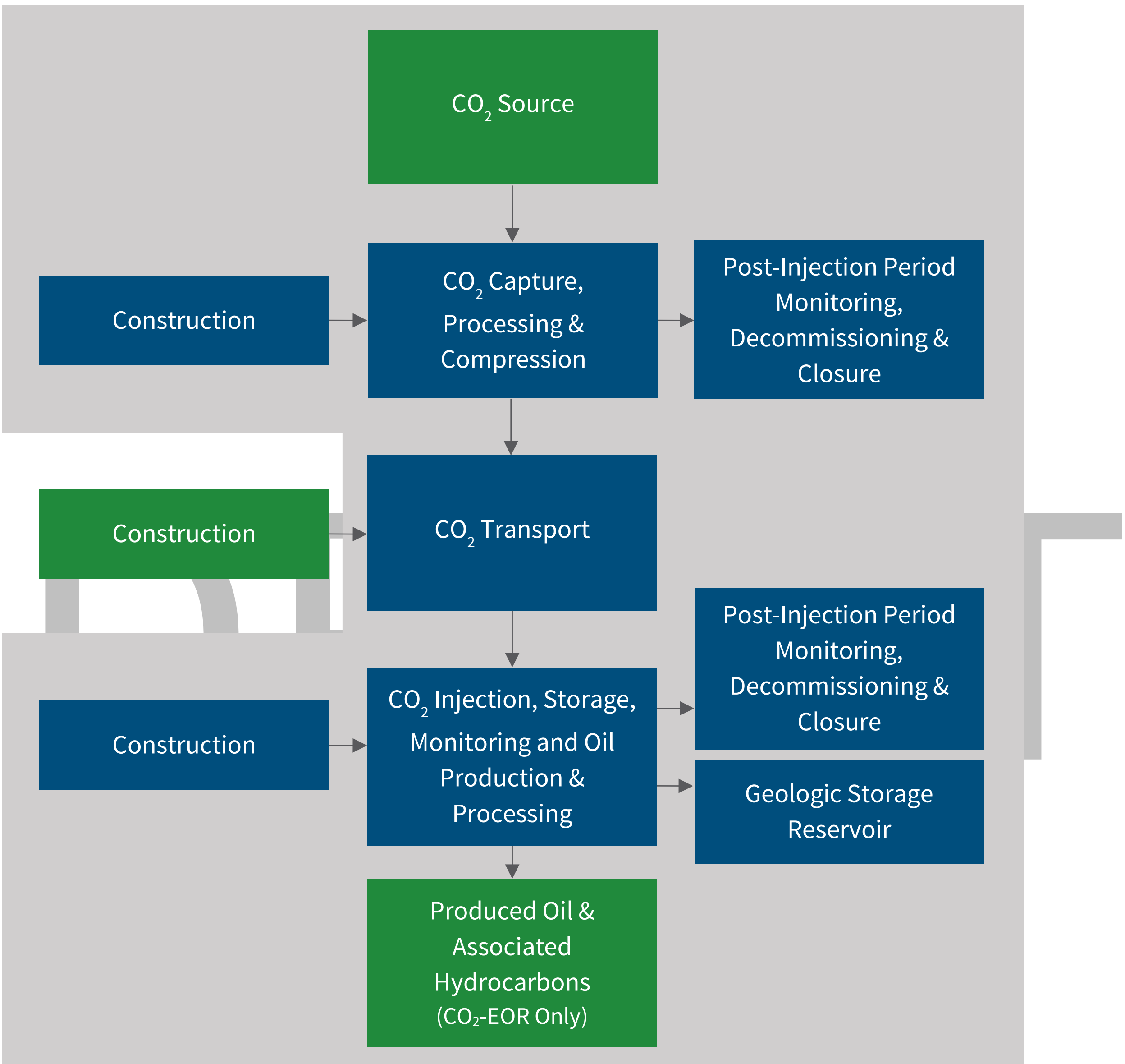
To ensure that the emission reductions calculation approach reflects the relevant change in emissions due to the project, the physical boundary shall incorporate all GHG sources affected by the project in the baseline and with-project scenarios (i.e., the change in overall emissions due to capturing, 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 capture 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[35] 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.

[35] 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 means of transport, and the addition of geologic storage reservoirs.

For each registered GHG Project, a Project Proponent may only include project activities that result in GHG emissions reductions being generated within the geographic boundary of one country.[36] CCS projects are considered to reduce or remove emissions in the country in which the capture of the CO_2

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

emissions occurred. This will be reflected in the national accounting of the host jurisdiction unless otherwise agreed between the host jurisdiction and the jurisdiction where the CO_2 is stored in cases where they are different.

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[37]	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.
CO_2 CAPTURE, PROCESSING, & COMPRESSION	Combustion emissions associated with CO_2 capture, processing, and	CO_2, CH_4, N_2O	I	This source is the primary contributor to the CO_2 stream

[37] Everywhere that stationary combustion is referred to in Table 3 and 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).

SSR	GHG SOURCES, SINKS AND RESERVOIRS	GHGs	INCLUDED (I) OR EXCLUDED (E)	JUSTIFICATION
	compression processes			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 small portion of the project's total emissions.
	CO_2 transferred to another entity and not injected for permanent storage [38]	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 of the project's total emissions.

[38] 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
	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 (pipeline transport only)	CO_2	I	Emissions associated with this source may represent a small portion of the project's total emissions.
CO_2 INJECTION, STORAGE, MONITORING AND OIL PRODUCTION & PROCESSING	Combustion emissions from operation of equipment associated with injection, storage, monitoring and on-site oil production & 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 and on-site oil production & processing	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 injection,	CO_2, CH_4	I	Emissions associated with this source may represent a small

SSR	GHG SOURCES, SINKS AND RESERVOIRS	GHGs	INCLUDED (I) OR EXCLUDED (E)	JUSTIFICATION
	storage, monitoring and on-site oil production & processing			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 small portion of the project's total emissions.
	Cement, asphalt, iron and steel production emissions	CO_2, CH_4, N_2O	I	Emissions associated with this source may represent a moderate portion of the project's total emissions.
	Production of materials that enable CO_2 capture	CO_2	E	Emissions associated with this source are de minimis.
	Pipeline and pipeline manufacturing and construction emissions	CO_2, CH_4, N_2O	E	Equipment will long outlast the life of the project.

SSR	GHG SOURCES, SINKS AND RESERVOIRS	GHGs	INCLUDED (I) OR EXCLUDED (E)	JUSTIFICATION
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 small 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 of the project's total emissions.
PRODUCED OIL & ASSOCIATED HYDROCARBONS (CO_2-EOR ONLY)	Crude oil and associated hydrocarbons 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

SSR	GHG SOURCES, SINKS AND RESERVOIRS	GHGs	INCLUDED (I) OR EXCLUDED (E)	JUSTIFICATION
				of the project's total emissions.
	Combustion of hydrocarbon 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
- For CO_2-EOR projects only; the project must start no later than December 31, 2029.

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 five (5) years. Where different Crediting Periods may apply, the shortest Crediting Period shall apply. [39]

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.

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. This time after the end of the Crediting post-injection monitoring period. The duration of the post-injection monitoring period shall be extended beyond five years based on the monitoring results obtained during this 5-year period and 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

The federal governments of both the U.S. and Canada have identified CCS as a critical component in achieving emission reduction goals. The U.S. executive identified CCS as essential for reducing difficult-

[39] e.g., project with only one DAC CO_2 source with CO_2-EOR shall have a Crediting Period of five (5) years, 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.

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 Emissions 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 hydrocarbons 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. but requires projects to demonstrate a net benefit to the atmosphere. However, since CO_2-EOR enables the production of fossil fuels that will contribute to emissions, the methodology requires that the downstream emissions from the production and use of the oil and associated hydrocarbons 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. If both baseline approaches are applicable to the project, 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.

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 [40] (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.

[40] 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 capture source: project-based and intensity-based. The more conservative baseline must be chosen. To be conservative, the baseline emissions equations do not include methane (CH_4) or nitrous oxide (N_2O).

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.

Alternatively, a similar power plant with higher efficiency could burn an equivalent amount of coal as the pre-retrofit plant and correspondingly produce the same amount of CO_2 as the baseline. In this case, the capture system would not cause an increase in total CO_2 production but it could lead to the generation of less electricity. In this case, if a Project Proponent uses actual electricity production data to derive baseline emissions, it could underestimate baseline emissions.

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, including process heaters, boilers, engines, turbines, or other fuel-fired equipment. The corresponding CO_2 emissions associated with this energy production must be included in baseline (and CO_2 capture source project) emissions.

Project Proponents shall adjust actual project data relied upon to quantify and/or validate baseline emissions. This is done to ensure a conservative baseline and that the quantified emissions reductions appropriately represent the atmospheric benefit of the CCS project and that the comparison between project and baseline emissions maintains functional equivalence.

In some cases, baseline emissions may have to be modified to ensure that projects are not credited for capture and storage of excess CO_2 emissions. The Project Proponent shall provide evidence that the CO_2 capture source facility was built and is being operated in accordance with its permit requirements and that there were no violations of permit conditions or exceedances in emissions of CO_2 and other pollutants. In the instance of a violation or exceedance, 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.

6.1.2 CO_2 SOURCE EMISSIONS WITH PROJECT-BASED BASELINE APPROACH

The project-based baseline requires actual measured 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. The procedure involves measuring or calculating the amount of CO_2 produced by the CO_2 capture source measured immediately downstream of the CO_2 capture source. As discussed above, an adjustment factor is a part of the equation to maintain functional equivalence between the baseline and project emissions. Project Proponents would determine the appropriate way to correct measured CO_2 emissions on a project-by-project basis 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

$$BE_{Project-Based_t} = \left(\sum_{c} \left(Vol._{Gas\ Produced_{c,t}} - Vol._{excess\ CO_{2_{c,t}}} \right) \times \%CO_{2_{c,t}} \times \rho CO_2 \times AF \right)$$

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** ($MTCO_2e$). This value divided by the adjustment factor (**AF**) shall be compared to $CO_2Injected_t$ (Equation 24) and the lesser value of these two values multiplied by **AF** shall be used for project-based baseline emissions.
$Vol._{Gas\ Produced_{c,t}}$	Total volume of gas (containing CO_2 and other compounds) produced and captured from CO_2 source **c**, measured at (or corrected to) standard conditions and metered at a point immediately downstream of the point of CO_2 capture, in reporting period **t** (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. For gasification projects, the volume and CO_2 content of the syngas produced from the gasifier shall be measured at a point upstream of the water-gas shift reactor and subsequent hydrogen purification steps.
$Vol._{excess\ CO_{2_{c,t}}}$	Volume of excess CO_2 gas produced from CO_2 source **c** due to permit exceedances (if any) during reporting period **t**, measured at (or corrected to)

	standard conditions[41] (m^3 gas) The exceedances shall include both official violations and any self-reported exceedances.
$\%CO_{2_{c,t}}$	Concentration of CO_2 in the gas stream from CO_2 capture source **c**, measured $Vol._{Gas\ Produced_{c,t}}$, in reporting period **t** (%CO_2 by volume, expressed as a decimal).
ρCO_2	Density of CO_2 at standard conditions = 0.001858 metric ton/m^3.
AF	Baseline adjustment factor to account for incremental CO_2 from the capture equipment and included in the measured CO_2 stream (unitless),[42] determined on a project-by-project basis. For example, if the entirety of the CO_2 capture source is separately run and operated and the corresponding CO_2 emissions are not included in the $Vol._{Gas\ Produced_{c,t}}$ term, insert 1 (one) for this term. If 25% of the total emissions from the CO_2 capture source are from the CO_2 capture equipment, an adjustment factor of 0.75 shall be used. **NOTE:** GHG emissions from the capture system are still attributable to the project activity and must be quantified and included in project emissions as discussed in Section 6.2.1.

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 2 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

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

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

output value used to calculate baseline emissions shall be set to ensure that the quantified emissions 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.

Equation 2: CO_2 Source Emissions With Intensity-Based Baseline Approach

$$\mathbf{BE_{intensity-based_t}} = \sum_{c} \mathbf{BE_{performance\ standard_{c,t}}} \times \mathbf{Output_{c,t}}$$

WHERE

$BE_{intensity-based_t}$	Intensity-based baseline emissions for all CO_2 capture sources **c** in reporting period **t** ($MTCO_2e$).
$BE_{intensity\ metric_{c,t}}$	Baseline emissions intensity metric, specific to the type of CO_2 capture 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 output (e.g., MWh, MMscf) of CO_2 capture 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.

Equation 3: Total Project Emissions

$$PE_t = PE_{Capture_t} + PE_{Transport_t} + PE_{Storage_t} + PE_{Construct-Pre_t} \times \frac{RP_t}{Days \times AP_{Construct}} + PE_{Construct-RP_t} + CO2_{Atm\ Leakage-Inj_t} + PE_{Post-Inj} + PE_{hydrocarb_t}$$

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 oil production and processing in reporting period **t** ($MTCO_2e$). Refer to Section 6.2.3.
$PE_{Construct-Pre_t}$	GHG emissions associated with CCS project pre-Crediting Period construction applied to reporting period **t** ($MTCO_2e$). Refer to Section 6.2.4.
$AP_{Construct}$	Period over which pre-Crediting Period construction emissions are applied (years). This number shall be either 1 or 10 for non-CO_2-EOR projects, and 1 or 5 for CO_2-EOR projects. If $AP_{Construct}$ = 1, all $PE_{Construct-Pre_t}$ 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.
$CO2_{Atm\ Emissions-Inj_t}$	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 6.2.6.

$PE_{Post-Inj}$	GHG emissions associated with CCS project monitoring, decommissioning, and closure in the post-injection period ($MTCO_2e$). These project emissions shall be accounted for according to the instructions in Table 8. They are not accounted for in any reporting periods. See Equation 28.
$PE_{Hydrocarb_t}$	GHG emissions from produced oil and associated hydrocarbons, including transport, processing and refining, and combustion [43] (for CO_2-EOR projects). Refer to Section 6.2.5.

6.2.1 CO_2 CAPTURE, PROCESSING & COMPRESSION EMISSIONS

The following equation outlines the methods for calculating atmospheric emissions from the capture segment of CCS project. This includes emissions from the equipment added to or installed as part of the CO_2 capture source to facilitate the capture and processing of the CO_2

Equation 4: Total Project Emissions from the Capture, Processing, and Compression Segment

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

WHERE

$PE_{Capture_t}$	Project emissions associated with all CO_2 capture, processing, and initial compression equipment in reporting period **t** ($MTCO_2e$).
$PE_{C-Source_t}$	GHG emissions from all equipment associated with all CO_2 sources that have not been captured by the CO_2 capture process in reporting period **t** ($MTCO_2e$). Refer to Equation 5 through Equation 8.

[43] 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).

PE_{C-Comb_t}	GHG emissions associated with all CO_2 capture, processing, and compression equipment associated with all CO_2 sources in reporting period **t** ($MTCO_2e$). This includes indirect emissions from offsite electricity used to operate the CO_2 source, capture, and compression equipment associated with all CO_2 sources. 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 in reporting period **t** ($MTCO_2e$).
$PE_{C-Vented_t}$	GHG emissions associated with venting of GHGs from capture, processing, and compression equipment associated with all CO_2 sources in reporting period **t** ($MTCO_2e$). Refer to Equation 21.

Consistent with the objective of providing a complete assessment of the impact of the CCS project, this quantification method accounts for all non-captured emissions from CO_2 capture, processing, and compression equipment. The calculation approach collectively refers to CO_2 created by equipment associated with CO_2 capture that is emitted to the atmosphere through vent stacks and fugitive releases from equipment at the capture, processing, and compression systems as non-captured CO_2.

The following equations account for the portion of CO_2 generated from equipment associated with CO_2 capture that is not captured but is instead emitted to the atmosphere. Project Proponents calculate emissions by subtracting CO_2 transferred to the transport segment of the CCS project from total CO_2 produced from the CO_2 capture, processing, and compression equipment. Section 7 provides the monitoring parameters to calculate total CO_2 produced from the CO_2 capture source and transferred to the CO_2 pipeline during the reporting period; it also provides the monitoring parameters necessary for calculating the CH_4 and N_2O emissions from the CO_2 capture source.

Equation 5: Project Emissions from CO_2 Capture Source Processes

$$\mathbf{PE_{C-Source_t} = CO_2\ Produced_{Source_t} + PE_{C-Offsite\ CO_2Transfer_t} - CO_2\ Transferred_{ToTranspo_t}}$$

WHERE

$PE_{C-Source_t}$	Project emissions from all CO_2 capture, processing, and compression processes associated with[44] all CO_2 sources that are not captured in reporting period **t** ($MTCO_2$).
$CO_2\ Produced_{Source_t}$	Total CO_2 produced and captured from all CO_2 sources in reporting period **t** ($MTCO_2$). Refer to Equation 6.
$PE_{C-Offsite\ CO_2Transfer_t}$	All CO_2 transferred outside the project boundary after CO_2 capture but before any CO_2 is transferred to the first means of transport in reporting period **t** ($MTCO_2e$). Refer to Equation 7.
$CO_2\ Transferred_{To\ Transpo_t}$	CO_2 from all CO_2 capture, processing, and compression processes associated with all CO_2 sources transferred to the first means of transport (e.g., truck, CO_2 pipeline) in reporting period t ($MTCO_2e$). Refer to Equation 8.

The following equation shall be used to calculate CO_2 emissions captured from the CO_2 source.

Equation 6: CO_2 Emissions Captured from CO_2 Source

$$\mathbf{CO_2\ Produced_{Source_t} = \sum_c \left[\left(Vol._{Gas\ Produced_{c,t}} - Vol._{excess\ CO_{2_{c,t}}}\right) \times \%CO_{2_{c,t}}\right] \times \rho CO_2 + \sum_x \left[\left(Vol._{Secondary_{x,t}} - Vol._{excess\ CO_{2_{x,t}}}\right) \times \%CO_{2_{x,t}}\right] \times \rho CO_2}$$

WHERE

$CO_2\ Produced_{Source_t}$	Total CO_2 produced and captured from all CO_2 sources in reporting period **t** ($MTCO_2$).

[44] i.e., each CO_2 capture, processing, and compression process located near each separate CO_2 source.

$Vol._{Gas\ Produced_{c,t}}$	Total volume of gas (containing CO_2 and other compounds) produced and captured from CO_2 source **c**, measured at (or corrected to) standard conditions and metered at a point immediately downstream of point of CO_2 capture, in reporting period **t** (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.
$Vol._{excess\ CO_{2_{c\ or\ x,t}}}$	Volume of excess CO_2 gas produced from CO_2 source **c** or **x** due to permit exceedances (if any) and captured during reporting period **t**, measured at (or corrected to) standard conditions (m^3 gas). The exceedances shall include both official violations and any self-reported exceedances.
$\%CO_{2_{c,t}}$	Concentration of CO_2 in the gas stream from CO_2 capture source **c**, measured immediately downstream of $Vol._{Gas\ Produced_{c,t}}$, 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.
$Vol._{Secondary_{x,t}}$	Total volume of gas (containing CO_2 and other compounds) associated with capture source **x**, which excludes primary CO_2 source **c**, measured continuously at (or corrected to) standard conditions at a point immediately downstream of CO_2 source **x** in reporting period **t** (m^3). This only includes the capture of CO_2 from equipment associated with the project (i.e., equipment that exists to facilitate activities associated with the project like CO_2 capture).
$\%CO_{2_{x,t}}$	Concentration of CO_2 in the gas stream from CO_2 source **x**, which excludes primary CO_2 source **c**, measured at (or corrected to) standard conditions immediately downstream of $Vol._{Secondary_{x,t}}$ in reporting period **t** (%CO_2 by volume, expressed as a decimal).

Equation 7 presents the approach to calculate CO_2 transferred outside the project boundary. This can occur at any point in the project and shall be accounted for in the project segment in which the transfer occurs.

Equation 7: CO_2 Transferred Outside Project Boundary

$$PE_{Offsite\ CO_2 Transfer_t} = Vol_{CO_2 Transfer_t} \times \rho CO_2$$

WHERE

$PE_{Offsite\ CO_2 Transfer_t}$	All CO_2 transferred outside the project boundary in a particular project segment (i.e., capture, transport, storage) reporting period **t** ($MTCO_2$).
$Vol._{CO_2 Transfer_t}$	Volume of CO_2 transferred outside the project boundary in a particular project segment 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 immediately downstream of the gas volume measurement.
ρCO_2	Density of CO_2 at standard conditions = 0.001858 metric tons/m^3.

Equation 8: CO_2 Captured and Input into CO_2 Transport

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

WHERE

$CO_2\ Transferred_{Transpo_t}$	Total CO_2 captured and transferred to the first CO_2 means of transport in reporting period **t** ($MTCO_2$).
$Vol._{Gas\ Transferred_{c\&x,t}}$	Total volume of gas captured from each CO_2 source **c** and input into the first means of transport, metered at the point of transfer to the means of transport, in reporting period **t** (m^3gas). Refer to Equation 12.
$\%CO_{2_{Gas\ Transferred_{c,t}}}$	Concentration of CO_2 in the gas stream from CO_2 source **c** measured at standard conditions at the input to the means of transport, 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.

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 (CO_2 capture source) 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 equipment used for CO_2 capture, processing, and compression including GHG emissions in situations in which a flare is used to combust gases, and GHG emissions associated with the use of offsite electricity and thermal energy to power capture, processing, and compression equipment.

Equation 9: Project Emissions Associated with Capture, Processing, and Compression Equipment Combustion

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

WHERE

PE_{C-Comb_t}	Project emissions from combustion of fuels in all equipment used to operate the CO_2 capture, processing, and compression facilities associated with all CO_2 sources in reporting period **t** ($MTCO_2e$).
$Fuel_{i,c,t}$	Volume or mass of fuel type **i**, used to operate the CO_2 capture, processing, and compression equipment associated with each CO_2 source **c** 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., $MTCH_4/m^3$ or $MTCH_4$/kg of fuel).
$EF\ N_2O_{Fuel_i}$	N_2O emission factor for combustion of fuel **i** (e.g., MTN_2O/m^3 or MTN_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.
$PE_{Flaring_{c,t}}$	Project emissions from the flaring of gases associated with all CO_2 capture, processing, and compression equipment associated with all CO_2 sources **c** in reporting period **t** ($MTCO_2e$). Refer to Equation 10.
$PE_{Indirect\ Energy_{c,t}}$	Project emissions from offsite electricity and thermal energy used to operate CO_2 capture, processing, and compression equipment associated with all CO_2 sources **c** in reporting period **t** ($MTCO_2e$). Refer to Equation 11.

Equation 10: Project Emissions from Gas Flaring

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

WHERE

$PE_{Flaring_t}$	Project emissions from the flaring of gases associated with the relevant CCS project segment[45] in reporting period **t** ($MTCO_2e$).
$Gas\ Flared_{i,t}$	Volume of gas flared, by gas type **i** in reporting period **t** (m^3).
$Flare\ Fuel_{j,t}$	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.

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

0.92	Destruction efficiency of flares.[46]
$\%CH_{4_t}$	Concentration of CH_4 in the gas stream 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.
$EF\ CO_{2_{Flare\ Fuel_j}}$	CO_2 emission factor for flare fuel **j** (e.g., $MTCO_2/m^3$ or $MTCO_2$/kg fuel).
$EF\ N_2O_{Gas\ Flared_i}$	N_2O emission factor for gas flared **i** (e.g., MT N_2O/m^3 or MT N_2O/kg fuel).
$EF\ N_2O_{Flare\ Fuel_j}$	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.

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, operating 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.

[46] The most conservative of the default flare destruction efficiencies (98%, 95%, and 92%) from U.S. EPA (2025f).

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[47] in reporting period **t** ($MTCO_2e$).
$Electricity_{e,t}$	Metered offsite electricity source **e** used to operate the relevant equipment in reporting period **t** (e.g., MWh).
$EF_{Electricity_{e,t}}$	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 F for emission factor guidance.
$Thermal\ Energy_{h,t}$	Offsite thermal energy **h** used to operate relevant equipment in reporting period **t** (MMBtu)
$EF_{Thermal\ Energy_h}$	Emission factor (for CO_2, CH_4, and N_2O) associated with offsite thermal energy **h** used to operate relevant equipment ($MTCO_2e$/MMBtu). Refer to Appendix F for emission factor guidance.

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 capture source) to the CO_2 transfer point at the injection and storage site. The calculation methodology applies to CO_2 transported via pipelines or in containers (i.e., rail lines, roads, maritime ships, barges,

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

intermodal transport). The following equation shows an approach to calculate GHG emissions from the transport segment of a CCS project.

Equation 12: Total Project Emissions from the Transport Segment

$$\mathbf{PE_{Transport_t} = PE_{T-Pipeline-single_t} + PE_{T-Pipeline-mixed_t} + PE_{T-Mobile_t} + PE_{T-Offsite\ CO_2 Transfer_t} + PE_{T-Vented\ CO_{2_t}}}$$

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 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 (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.
$PE_{T-Offsite\ CO_2 Transfer_t}$	CO_2 transferred outside the project boundary after CO_2 is transferred to the first means of transport but before it is delivered to the storage facility in reporting period **t** ($MTCO_2e$). Refer to Equation 7.
$PE_{T-Vented\ CO_{2_t}}$	Vented CO_2 from all pipelines used only by this CCS project and mobile means of transport in reporting period **t** ($MTCO_2e$). Refer to Equation 21.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

$$\begin{aligned}PE_{T-Pipeline-single_t} &= \sum_i (Fuel_{i,p,t} \times EF\ CO2_{Fuel_i}) \times GWP_{CO_2} \\ &+ \sum_i (Fuel_{i,p,t} \times EF\ CH4_{Fuel_i}) \times GWP_{CH_4} \\ &+ \sum_i (Fuel_{i,p,t} \times EF\ N_2O_{Fuel_i}) \times GWP_{N_2O} + PE_{T-Flaring_{p,t}} + PE_{T-Fug_{p,t}} \\ &+ PE_{S-Fug_t} + \sum_i (Electricity_{i,p,t} \times EF_{Electricity_{i,p,t}})\end{aligned}$$

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).
$EF\ CO2_{Fuel_i}$	CO_2 emission factor for combustion of fuel **i** (e.g., $MTCO_2/m^3$ or $MTCO_2/kg$ of fuel).
$EF\ CH4_{Fuel_i}$	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 22.
$Electricity_{i,p,t}$	Metered offsite electricity **i** used to operate all equipment associated with CO_2 transportation segment (pipeline **p**) used only by the CCS project in reporting period **t** (e.g., MWh).
$EF_{Electricity_{i,p,t}}$	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 factors.

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

$$\mathbf{PE}_{\mathbf{T-Pipeline-mixed}_t} = \sum_q \left[\left(\mathbf{Distance - Pipeline}_{q,t}\right) \times \left(\mathbf{EF\ Pipeline\ Operation}_{q,t} + \mathbf{Pipeline\ Leakage}_{CO_{2_{q,t}}}\right) \times \mathbf{t/year} \right]$$

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 and emissions associated with offsite electricity—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).
$Pipeline\ Leakage_{CO_{2_{q,t}}}$	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. [48]
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

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

WHERE

$Metric\ ton\text{-}mile_{prod,t}$	Distance traveled (in miles) by product **prod** with mass $Mass\ Product_{prod,p\ or\ q\ or\ r,t}$ in reporting period **t** (metric ton-miles).

[48] 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).

$\text{Mass Product}_{\text{prod,p } or \text{ q } or \text{ r,t}}$	Mass of product **prod** transported via means of transport **p** (single-use pipeline) *or* **q** (mixed-use pipeline) *or* **r** (mobile means of transport) 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.
$\text{Distance}_{\text{prod,p } or \text{ q } or \text{ r,t}}$	Distance that product **prod** traveled via means of transport **p**, **q**, or **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. Total CO_2e emissions are calculated using the following equation.

Equation 16: Project Emissions from Mobile Transport

$$\mathbf{PE_{Mobile_t}} = \sum_{\mathbf{r}}\left(\textbf{Metric ton-mile}_{\mathbf{r,t}} \times \textbf{EF CO}_{\mathbf{2_r}} \times \mathbf{10^{-3}}\right) \times \mathbf{GWP_{CO_2}} + \sum_{\mathbf{r}}\left(\textbf{Metric ton-mile}_{\mathbf{r,t}} \times \textbf{EF CH}_{\mathbf{4_r}} \times \mathbf{10^{-6}}\right) \times \mathbf{GWP_{CH_4}} + \sum_{\mathbf{r}}\left(\textbf{Metric ton-mile}_{\mathbf{r,t}} \times \textbf{EF N}_{\mathbf{2}}\mathbf{O_r} \times \mathbf{10^{-6}}\right) \times \mathbf{GWP_{N_2O}}$$

WHERE

$\text{PE}_{\text{Mobile}_t}$	Project emissions from all modes of mobile transport that were used to transport a product 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** ($MTCO_2e$).
$\text{Metric ton-mile}_{\text{r,t}}$	Metric ton-miles for each mode of mobile transport mode **r** (rail, truck, maritime ship, or barge) a product 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 F for further details on emission factors.
$EF\ CH_{4_r}$	CH_4 emission factor for mobile transport mode **r** (g/metric ton-mile). Refer to Appendix F for further details on emission factors.
$EF\ N_2O_r$	N_2O emission factor for mobile transport mode **r** (g/metric ton-mile). Refer to Appendix F for further details on emission factors.
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 Transferred from CO_2 Pipelines to CO_2 Storage Sites

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

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** ($MTCO_2e$).
$Vol._{Gas\ Transferred\ to\ Storage_{p,r,t}}$	Volume of gas that has been transferred to the injection and storage site operator by single-user CO_2 pipeline **p** and mobile means of transport **r** to the storage site in reporting period **t** (m^3). Gas volume shall be measured at the point(s) of transfer at standard conditions.
$\%CO_{2_t}$	Concentration of CO_2 in the gas stream measured at the point(s) of transfer with the storage site (%CO_2 by volume, expressed as a decimal). [49]
ρCO_2	Density of CO_2 at standard conditions = 0.001858 metric tons/m^3.

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

Equation 18: Project Emissions from CO_2 Vented from Pipelines Used only by this CCS Project

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

WHERE

$PE_{T-Vented\ CO_{2_t}}$	Project emissions from CO_2 vented from all pipelines used only by this CCS project and mobile means of transport in reporting period **t** ($MTCO_2$). This term does not apply to CO_2 transported via CO_2 pipelines used by multiple parties.
$CO_2\ Transferred_{Transpo_t}$	Total CO_2 captured and transferred to the first CO_2 means of transport in reporting period **t** ($MTCO_2$). Refer to Equation 8.
$CO_2 Transferred_{Storage_t}$	Total CO_2 supplied to the injection and storage site operator by all single-user CO_2 pipelines and mobile means of transport reporting period **t** ($MTCO_2$). Refer to Equation 17.

6.2.3 CO_2 INJECTION, STORAGE, MONITORING & OIL PRODUCTION AND PROCESSING EMISSIONS

The emissions calculation procedures for CO_2 injection, storage, monitoring, and oil production and (onsite) processing (the latter for CO_2-EOR projects only) 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 equipment; indirect CO_2e emissions from offsite electricity and thermal energy; and transfer of CO_2 outside the project boundary. This includes all emissions sources located between the point of transfer from the CO_2 means of transport up to and including the injection wells and any production wells within the injection site area of review.

Equation 19 outlines the methods for calculating emissions from CO_2 injection, storage, monitoring, and oil production and onsite processing Section 7 provides monitoring parameters for calculating emissions from CO_2 storage.

Equation 19: Total Project Emissions from CO_2 Injection, Storage, Monitoring & Oil Production and Processing

$$PE_{Storage_t} = PE_{S\text{-}Comb_t} + PE_{S\text{-}Vent_t} + PE_{S\text{-}Fug_t} + PE_{S\text{-}Offsite\ CO_2 Transfer_t} + PE_{S\text{-}Entrained_{CO_{2t}}}$$

WHERE

$PE_{Storage_t}$	Project emissions associated with CO_2 injection, storage, monitoring, and oil production and 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 oil production and processing (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, CO_2 recycling devices, and production wells (for CO_2-EOR projects), hydrocarbon processing facilities, and monitoring equipment. Refer to Equation 20.
$PE_{S\text{-}Vent_t}$	Emissions from venting of GHGs associated with CO_2 injection, storage, monitoring, and oil production and processing (the latter for CO_2-EOR projects only) operations in reporting period **t** ($MTCO_2e$). For CO_2-EOR projects, this also includes GHG emissions at the producing wells and at the CO_2 processing and recycling facilities. Refer to Equation 21.
$PE_{S\text{-}Fug_t}$	Fugitive emissions at the injection wells or other surface facilities located between the point of transfer from the CO_2 transport segment and the AoR Boundary. For CO_2-EOR projects this also includes GHG emissions at the producing wells, at the hydrocarbon gathering processing and storage facilities, or at the CO_2 processing and recycling facilities in reporting period **t** ($MTCO_2e$). Refer to Equation 22.
$PE_{S\text{-}Offsite\ CO_2 Transfer_t}$	CO_2 transferred outside the project boundary after the point at which CO_2 is transferred to the injection and storage site and not contained in hydrocarbons or produced water transferred outside the project boundary, in reporting period **t** ($MTCO_2$). Refer to Equation 7. This *excludes* CO_2 accounted for in Equation 23 ($PE_{S\text{-}Entrained_{CO_{2t}}}$).

$PE_{S\text{-}Entrained_{CO_2}{}_t}$	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 23. This *excludes* CO_2 accounted for in $PE_{S\text{-}Offsite\ CO_2 Transfer_t}$.

Various types of equipment may be used to maintain and operate CO_2 injection, storage, monitoring, and oil production and 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, and oil production and 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); or CO_2 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 and other gases 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 20: Project Emissions from Combustion Associated with Injection, Storage, Monitoring & Oil Production and Processing

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

WHERE

PE_{S-Comb_t}	Project emissions from the use of equipment associated with all injection, storage, monitoring, and oil production and 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 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 F.
$EF\ CH_{4_{Fuel_i}}$	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/kg of fuel).
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 oil production and 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. CO_2 vented from the geologic storage reservoir downstream of the injection well(s) (for non-EOR projects) and production well(s) (if applicable) shall be accounted for using Equation 31.

Equation 21: 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 retained by injection and storage site operator.
$V_{Blowdown_{i,t}}$	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 22: Project Emissions from Equipment Leaks (i.e., Fugitive Emissions)

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

WHERE

$PE_{Seg-Fug_t}$	Project emissions from fugitive GHG emissions (CO_2 and CH_4) from equipment in a specified project segment **seg** (e.g., capture, transport, storage) in reporting period **t** ($MTCO_2e$).
$Count_{s,seg,t}$	Total number of each type of emission source **s** (e.g., wells, equipment) in project segment **seg** 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.
$T_{s,seg,t}$	Total time that the equipment associated with emission source **s** in product segment **seg** 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 standard conditions (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 23 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 21.

Equation 23 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 19).

Equation 23: 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 transported outside of the project boundary that is accounted for under other equations (e.g., Equation 19).
$\%CO_{2\ Hydrocarbon\ Gas_{g,t}}$	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).
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.
$\text{Mass Frac}_{CO_2 \text{ in Water}_{g,t}}$	Mass fraction of CO_2 in the water produced from geologic storage reservoir **g** in reporting period **t** (decimal fraction).
$\text{Mass}_{\text{Oil Prod}_{g,t}}$	Mass of crude oil and other liquid hydrocarbons produced from geologic storage reservoir **g** in reporting period **t** (MT).
$\text{Mass Frac}_{CO_2 \text{ in Oil Prod}_{g,t}}$	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).
$\text{Mass Frac}_{\text{Vented } CH_4 \text{ in Water Prod}_{g,t}}$	Mass fraction of CH_4 in the water produced from geologic storage reservoir **g** in reporting period **t** that is vented to the atmosphere (decimal fraction).
$\text{Mass Frac}_{\text{Vented } CH_4 \text{ in Oil Prod}_{g,t}}$	Mass fraction of CH_4 in the crude oil and other liquid hydrocarbons produced from geologic storage reservoir **g** in reporting period **t** that is vented to the atmosphere (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, 2010).

Equation 24: CO_2 Injected Underground at the CO_2 Injection & Storage Site

$$CO_2Injected_t = \sum_g \sum_w \left(Mass_{Injected_{w,g,t}}\right)$$

WHERE

$CO_2\ Injected_t$	Total CO_2 injected into wells in all geologic storage reservoirs, metered 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**, metered 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 3, the Project Proponent may apply construction project emissions either to the first reporting period or apply them on a proportional basis over the Crediting Period.

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.

Unless specified, emissions associated with the production of large equipment that will outlast the life of the project (e.g., CO_2 pipelines, compression units, cranes, forklifts, trucks, loaders) are excluded from the project boundary.

Equation 25: Total Project Emissions from Pre-Crediting Period Construction

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

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 27.
$PE_{Construct-Pre-Materials}$	GHG emissions from production of construction materials for the CCS project before the Crediting Period ($MTCO_2e$). Refer to Equation 27.

Equation 26: Total Project Emissions from Construction During a Reporting Period

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

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 27.
$PE_{Construct-RP-Materials_t}$	GHG emissions from production of construction materials for the CCS project in reporting period **t** ($MTCO_2e$). Refer to Equation 28.

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 27: Project Emissions From Non-Transport-Related Combustion of Fuels to Operate Construction Equipment

$$PE_{Construct-RP-Comb_t} = \sum_{i}\sum_{eq}(Fuel_{eq,i,t} \times EF\ CO2_{Fuel_i}) \times GWP_{CO_2} + \sum_{i}\sum_{eq}(Fuel_{eq,i,t} \times EF\ CH4_{Fuel_i}) \times GWP_{CH_4} + \sum_{i}\sum_{eq}(Fuel_{eq,i,t} \times EF\ N_2O_{Fuel_i}) \times GWP_{N_2O} + \sum_{eq} PE_{S-Flaring_{eq,t}} + \sum_{eq} PE_{S-Indirect\ Energy_{eq,t}}$$

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** ($MTCO_2e$).
$Fuel_{eq,i,t}$	Volume or mass of fuel type **i** used to operate construction equipment **eq** in reporting period **t** (e.g., m^3, kg).
$EF\ CO2_{Fuel_i}$	CO_2 emission factor for combustion of fuel **i** (e.g., $MTCO_2/m^3$ or $MTCO_2/kg$ of fuel). Refer to Appendix F.
$EF\ CH4_{Fuel_i}$	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/kg of fuel).
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 28: GHG Emissions from Construction Materials

$$\mathbf{PE_{Construct-RP-Materials_t} = \sum_{m}(Mass_{m,t} \times Material\ EF_{m,t})}$$

WHERE

$PE_{Construct-RP-Materials_t}$	GHG emissions associated with the production of all construction materials for the CCS project in reporting period **t** or before the start of the Crediting Period, as applicable ($MTCO_2e$).
$Mass_{m_t}$	Mass or weight of material **m** brought into use at the CCS project in reporting period **t** before the start of the Crediting Period, as applicable (e.g., kg, g, lb.).
$Material\ EF_{m,t}$	Emission factor for material **m** utilized in the CCS project in reporting period **t** before the start of the Crediting Period, as applicable ($MTCO_2e$ per unit mass or weight). Refer to Table 6 for construction material emission factors.

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

Table 6: Emission Factors for Construction Materials

MATERIAL	EMISSION FACTOR
CEMENT	0.886 $MTCO_2$ / MT cement[50]
ASPHALT MIXTURE	0.0521 $MTCO_2e$ per short ton of asphalt mix[51]
IRON & STEEL	1.06 $MTCO_2$ per MT of iron or steel produced[52]

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 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

[50] 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, and adjusted to account for materials blended with the clinker. Emissions from biogenic fuels (which were <1% for most plants using CEMS), methane (CH_4), and nitrogen oxide (NO_2) were excluded. 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.

[52] The emission factor of 1.06 MT CO_2 per MT of iron or steel produced is derived from IPCC's global average factor for steelmaking, which is weighted by the market shares of the different production methods (Volume 3 of IPCC, 2006).

deconstruction of any facilities associated with capture at the CO_2 source as well as the injection and storage site. Post-injection period monitoring, decommissioning, and closure project emissions shall be quantified using the following equation.

Equation 29: Total Post-Injection Period Monitoring, Decommissioning, and Closure Project Emissions

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

WHERE

$PE_{Post-Inj}$	GHG emissions associated with CCS project monitoring, decommissioning, and closure in the post-injection period ($MTCO_2e$).
$PE_{Post-Inj-Transpo}$	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 electricity 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 20.
$PE_{Construct-Materials}$	GHG emissions associated with the production of all construction materials used for the CCS project during decommissions and closure, as applicable ($MTCO_2e$). Refer to Equation 28.

6.2.6 PRODUCED OIL & ASSOCIATED HYDROCARBONS 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 hydrocarbons 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 hydrocarbon production occurs. Equation 30 presents the approach to calculate GHG emissions from oil and associated hydrocarbons produced by a project.

Equation 30: Total Project Emissions from Produced Oil & Associated Hydrocarbons

$$\mathbf{PE_{Hydrocarbon_t}} = \sum_{g} \Big[\mathbf{Vol.\,Crude_{g,t}} \times \Big(\mathbf{EF_{Hydrocarb-Transpo_{g,t}}} + \mathbf{EF_{Hydrocarb-Refining_{g,t}}} + \mathbf{EF_{Hydrocarb-Processing_{g,t}}} + \mathbf{EF_{Hydrocarb-End\ Use_{g,t}}}\Big) \times \mathbf{0.001}\Big]$$

WHERE

$PE_{Hydrocarbon_t}$	Transport, refining and processing, and end use emissions from all oil and associated hydrocarbons produced in reporting period **t** ($MTCO_2e$).
$Vol.\,Crude_{g,t}$	Volume of crude oil and associated hydrocarbons produced from geologic storage reservoir **g** in reporting period **t**, metered immediately before custody transfer to another entity and shipment offsite of the CO_2 storage location (bbl).
$EF_{Hydrocarb-Transpo_{g,t}}$	Emission factor for the transport of oil and associated hydrocarbons produced from 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 31 and Appendix B, Section B.1.
$EF_{Hydrocarb-Refining_{g,t}}$	Emission factor for refining of oil produced from geologic storage reservoir **g** during reporting period **t** ($kgCO_2e$/bbl). Refer to Appendix B, B.2. If calculating project-specific refining emissions, Project Proponents must supply documentation to the VVB detailing refinery-specific emission factors.
$EF_{Hydrocarb-Processing_{g,t}}$	Emission factor for non-refining emissions for processing of associated hydrocarbons produced from geologic storage reservoir **g** during

	reporting period **t** ($kgCO_2e/bbl$). This only applies to processing that occurs downstream of the injection and storage site. Refer to Appendix B. If calculating project-specific processing emissions, Project Proponents must supply documentation to the VVB detailing processing-specific emission factors.
$EF_{Hydrocarb-End\ Use_{g,t}}$	Emission factor for end use (combustion) of the petroleum and gas end products created from the oil and associated hydrocarbon produced from geologic storage reservoir **g** during reporting period **t** ($kgCO_2e/bbl$). Refer to Appendix B, Section B.3.
0.001	Conversion factor to convert from kg to metric tons.

Equation 31: Emissions from Transport of Oil, Associated Hydrocarbons, & Refined and Processed Products

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

WHERE

$EF_{Hydrocarb-Transpo_t}$	Emission factors for the transport of oil and associated hydrocarbons produced from geologic storage reservoir **g** during reporting period **t**, including from CO_2 injection and storage site to refinery or other processing facility, refinery or other processing facility 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. 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).
$EF_{Hydrocarb-Transpo-Refinery_{g,t}}$	Emission factor for transport of crude oil and associated hydrocarbons produced from geologic storage reservoir **g** to refineries or other processing facilities during reporting period **t** ($kgCO_2e/bbl$). Directions on calculation of this emission factor can be found in Appendix B, Section B.1A.
$EF_{Hydrocarb-Transpo-Crude-Export_{g,t}}$	Transport emission factor for the export of crude oil and associated hydrocarbons produced from 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.
$EF_{Hydrocarb-Transpo-Terminals_{g,t}}$	Emission factor for the domestic transport of refined oil and processed associated hydrocarbons for which the crude oil and associated hydrocarbons were produced from 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.
$EF_{Hydrocarb-Transpo-Refined-Export_{g,t}}$	Transport emission factor for the export of refined oil and processed associated hydrocarbons for which the crude oil and associated hydrocarbons were produced from 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.

6.2.7 GEOLOGIC STORAGE RESERVOIR EMISSIONS

Project Proponents must demonstrate that there is a competent confining zone 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 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 estimate CO_2 emissions reaching the atmosphere, should that occur. This includes the use of conservative factors and algorithms in their estimates. Further, the uncertainty in the estimated value shall be calculated and included in the estimates. In the event of containment failure, a simplified estimation to conservatively determine maximum emissions can be used with Equation 32 and Equation 33.

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, 2010; U.S. EPA, 2025d). 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.

If the estimated emissions exceed the ERRs calculated for that reporting period (refer to Section 6.3 for calculation of ERRs), it shall be mitigated per the procedures discussed in Table 8.

Equation 32: 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 ($MTCO_2$).
$CO_{2_{z,t}}$	Total mass of CO_2 emitted through pathway **z** in geologic storage reservoir **g** in reporting period **t** ($MTCO_2$).

Equation 33 is used to report emission of CO_2 to the atmosphere that occurs after the injection period. Mitigation of post-injection emissions from the geologic storage reservoirs is discussed in Section 9.1.

Equation 33: Emissions from the CO_2 Storage Volume During the Post-Injection Period

$$CO_{2_{\text{Atm Emissions}-PI}} = \sum_{g}\sum_{z} CO_{2_{z,g}}$$

WHERE

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

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 34: Total Emission Reductions and Removals

$$\text{GHG ERR}_t = BE_t - PE_t$$

WHERE

GHG ERR_t	Total GHG emission reductions and removals from the CCS project in reporting period **t** ($MTCO_2e$).[53]
BE_t	Baseline CO_2e emissions removals or reductions in reporting period **t** ($MTCO_2e$). Refer to Equation 1 or Equation 2.
PE_t	Project CO_2e emissions in reporting period **t** ($MTCO_2e$). Refer to Equation 3.

[53] 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.

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

Equation 35: Reserve Account Contribution

$$\mathbf{RA_t = GHG\ ERR_t \times RA\%_t}$$

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 34.
$RA\%_t$	Percent of the Total Emission Reductions and Removals for reporting period **t** that must be held in the ACR Reserve Account, as determined by the ACR CCS Reversal Risk 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 36: 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 34.
RA_t	Reserve Account Contribution required for reporting Period **t** ($MTCO_2e$). Refer to Equation 35.

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 37: Net Emission Reductions and Removals by Vintage

$$\mathbf{NET\ ERR_{t,v} = NET\ ERR_t \times (CAL_v/CAL_t)}$$

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 36.
CAL_v	Number of days in reporting period **t** that fall within calendar year **v**.
CAL_t	Total number of days in reporting period **t**.

Equation 38: Reserve Account Contribution by Vintage

$$\mathbf{RA_{t,vy} = RA_t \times (CAL_v/CAL_t)}$$

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 35.
CAL_v	Number of days in reporting period **t** that fall within calendar year **v**.
CAL_t	Total number of days in reporting period **t**.

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.

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 produced oil and associated hydrocarbons 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 sequestered 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, accurate logs of 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 2) because that baseline is not affected by the addition of capture to a CO_2 source. In the event that both baseline emissions equations are applicable, Project Proponents must use the most conservative baseline scenario.

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 G).

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, 2025f).

Well-designed, site-specific MRV plans with ongoing monitoring requirements, as required in Section 7, enable detection and measurement 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 F 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 (or report via a required project report) and the VVB shall review the following materials provided by the Project Proponent:

- MRV Plan as outlined in Section 7.3;
- Project Proponents 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, consistent with the metric's scope and units. The Project Proponent shall provide justification for the use of the regulatory or other legally enforceable source of the emissions intensity metric utilized for Equation 2. 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 1 and Equation 6); and
- Environmental Assessment or Environmental Impact Statement, if required by the jurisdictional authority.

Table 7: Monitoring Parameters

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
			PROJECT-BASED BASELINE		
$Vol._{Gas\ Produced_{c,t}}$	Total volume of gas (containing CO_2 and other compounds) produced and captured from CO_2 source **c**, in reporting period **t**.	m^3	M	Continuous [55]	Meter shall be located 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. For gasification projects, the volume and CO_2 content of the syngas produced from the gasifier shall be measured at a point upstream of the water-gas shift reactor and subsequent hydrogen purification steps. This value is also reported in capture, processing, and compression processing emissions (see Equation 6).
$Vol._{excess\ CO_{2_{c,t}}}$	Volume of excess CO_2 gas produced from CO_2 source **c** due to permit violations (if	m^3	M & C	Continuous	The exceedances shall include both official violations and any self-reported exceedances.

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

[55] Measurement taken at least every 15 minutes.

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
	any) during reporting period **t**.				
$\%CO_{2_{c,t}}$	Concentration of CO_2 in the gas stream from CO_2 capture source **c** in reporting period **t**.	$\%CO_2$ by volume, expressed as a decimal	M	Monthly	Measured immediately downstream of $Vol._{Gas\ Produced_{c,t}}$. This value is also reported in capture, processing, and compression processing emissions (see Equation 6).
INTENSITY-BASED BASELINE					
$Output_{c,t}$	Total production output of the CO_2 capture source **c** in the project condition in reporting period **t**.	e.g., MWh, MMscf	M, C	Once per reporting period	Measurement based on the units of the legally enforceable intensity metric for the CO_2 source.
CAPTURE, PROCESSING & COMPRESSION SEGMENT					
$Vol._{excess\ CO_{2_{c\ or\ x,t}}}$	Volume of excess CO_2 gas produced from CO_2 source **c** or **x** due to permit violations (if any) during reporting period **t**.	m^3	M & C	Continuous	The exceedances shall include both official violations and any self-reported exceedances.
$Vol._{Secondary_{x,t}}$	Total volume of gas (containing CO_2 and other compounds) associated with capture source **x**, which	m^3	M	Continuous	Measured continuously at (or corrected to) standard conditions at a point immediately downstream of CO_2 source **x.** This only includes the

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
	excludes primary CO_2 source **c.**				capture of CO_2 from equipment associated with the project (i.e., equipment that exists to facilitate activities associated with the project like CO_2 capture).
$\%CO_{2_{x,t}}$	Concentration of CO_2 in the gas stream from CO_2 source **x**, which excludes primary CO_2 source **c.**	$\%CO_2$ by volume, expressed as a decimal	M	Monthly	Measured immediately downstream of $Vol._{Secondary_{x,t}}$.
$Vol._{CO_2 Transfer_t}$	Volume of CO_2 transferred outside the project boundary in the capture, processing, and compression segment.	m^3	M	Continuous	Measured at the point of transfer outside the project boundary. This assumes a pure stream of CO_2. If the gas stream is not 100% CO_2, volume shall be corrected by $\%CO_{2_t}$, which shall be measured immediately downstream of the gas volume measurement.
$Vol._{Gas\ Transferred_{c\&x,t}}$	Total volume of gas captured from each CO_2 source **c** and **x** input into the first means of transport.	m^3	M	Continuous	Metered at the point of transfer with the means of transport.

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
$\%CO_{2\,Gas\ Transferred_{c\&x,t}}$	Concentration of CO_2 in the gas stream from CO_2 sources **c** and **x** measured at standard conditions at the input to the pipeline or other means of transport, in reporting period **t** (% volume).	$\%CO_2$ by volume, expressed as a decimal	M	Continuous	Measured at the input to the transport segment.
$Vol._{Gas\ Transferred_{c,t}}$	Total volume of gas captured from each CO_2 source **c** and input into the first means of transport.	m^3	M	Continuous	Measured at the point of transfer with the means of transport.
$Fuel_{i,c,t}$	Volume or mass of each fuel used to operate the CO_2 capture, processing, and compression equipment associated with each CO_2 source **c**.	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 [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
$Gas\ Flared_{i,t}$	Volume of gas flared, by gas type **i**.	m^3	M	Continuous	Gas volume shall be metered at the flare.
$Flare\ Fuel_{j,t}$	Volume of each supplemental fuel, by fuel type **j** used to ensure complete combustion of the gases.	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**.	decimal fraction	M	Continuous or monthly	Measured using gas chromatograph.
$\%CH_{4_t}$	Concentration of CH_4 in the gas stream that is being flared.	$\%CH_4$ by volume, expressed as a decimal	M	Continuous or monthly	Measured at the input to the flare system.

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
$Electricity_{e,t}$	Metered offsite electricity source **e** used to operate equipment associated with the capture, processing, and compression segment.	e.g., MWh	M, O	Continuous or monthly	Continuous measurement of electricity consumption or monthly billing records from utility supplier, or r. 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 capture, processing, and compression segment.	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.
TRANSPORT SEGMENT					
$Vol._{CO_2 Transfer_t}$	Volume of CO_2 transferred outside the project boundary in the transport segment.	m^3	M	Continuous	Measured at the point of transfer outside the project boundary. This assumes a pure stream of CO_2. If the gas stream is not 100% CO_2, volume shall be corrected by $\%CO_{2_t}$, which

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
					shall be measured immediately downstream of the gas volume measurement.
$N_{Blowdown_{i,t}}$	Number of blowdowns (venting events) **i** from all pipelines used only by this CCS project and all mobile means of transport.	#	O, C	As occurs	Transport operators shall keep detailed logs of all venting incidents. This term does not apply to CO_2 transported via CO_2 pipelines used by multiple parties.
$V_{Blowdown_{i,t}}$	Total volume of blowdown equipment chambers for equipment **i** (including pipelines, manifolds, and vessels between isolation valves).	m^3	O, C	N/A	Volume can be estimated based on equipment specifications (e.g., pipeline diameters), flow meters, duration of event. This term does not apply to CO_2 transported via CO_2 pipelines used by multiple parties.
$\%GHG_{j,t}$	Concentration of GHG (CO_2 or CH_4) in vented substance **j**.	%GHG by volume, expressed as a decimal	M	Monthly	Measurement of the gas stream composition at the venting location. This term does not apply to CO_2 transported via CO_2 pipelines used by multiple parties.
$Fuel_{i,p,t}$	Volume or mass of fuel type **i** used to operate CO_2 pipeline	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

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
	p used only by the CCS project.				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.
$Gas\ Flared_{i,p,t}$	Volume of gas flared, by gas type **i**.	m^3	M	Continuous	Gas volume shall be metered at the flare. Gas volume shall be measured at standard conditions.
$Flare\ Fuel_{j,t}$	Volume of each supplemental fuel, by fuel type **j** used to ensure complete combustion of the gases.	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

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
					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**.	decimal fraction	M	Continuous or monthly	Measured using gas chromatograph.
$\%CH_{4_t}$	Concentration of CH_4 in the gas stream that is being flared.	$\%CH_4$ by volume, expressed as a decimal	M	Continuous or monthly	Measured at the input to the flare system.
$Count_{s,seg,t}$	Total number of each type of fugitive emission source **s** in project segment **seg** (transport).	#	O, C	N/A	Operator shall develop and maintain an equipment inventory to identify all possible fugitive emission sources from surface facilities and equipment in the transport 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.

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
$T_{s,seg,t}$	Total time that the equipment associated with fugitive emission source **s** in segment **seg** (transport) was operational.	hours	M, O, C	N/A	Measured or estimated based on operational records and downtime of the equipment in the transport 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 (CO_2 and CH_4) in fugitive emission source **s** in the transport segment.	%GHG by volume, expressed as a decimal	M	Monthly	Direct measurement of the composition of the gas stream.
$Electricity_{i,p,t}$	Metered offsite electricity **i** used to operate all equipment associated with CO_2 transport segment (pipeline **p**) used only by the CCS project.	e.g., MWh	M, O	Continuous or monthly	Continuous measurement of electricity consumption or monthly billing records from utility supplier, or r. 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 [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
					for each type of equipment and operating hours.
$\text{Mass Product}_{prod,p\ or\ q\ or\ r,t}$	Mass of product **prod** transported via means of transport **p** (single-use pipeline) *or* **q** (multiple-user pipeline) *or* **r** (mobile means of transport).	MT	M	Continuous	Metered continuously at the start and end of the transportation segment.
$\text{Distance}_{prod,p\ or\ q\ or\ r,t}$	Distance that product **prod** traveled via means of transport **p**, **q**, or **r**.	miles	M, O, C	Continuous.	Distance of travel shall be logged and tracked per shipment.
$\text{Vol.}_{\text{Gas Transferred to Storage}\ p,r,t}$	Volume of gas that has been transferred to the injection and storage site operator by single-user CO_2 pipeline **p** and mobile transportation medium **r** to the injection and storage site.	m^3	M	Continuous	Metered at the point of transfer with the injection and storage site.
$\%CO_{2_t}$	Concentration of CO_2 in the gas stream in the transportation segment in reporting period **t**.	$\%CO_2$ by volume, expressed	M	Continuous	Measured at the point(s) of transfer with the injection and storage site.

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
		as a decimal			
INJECTION, STORAGE, MONITORING & OIL PRODUCTION AND 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 processing facilities.	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.
$Gas\ Flared_{i,t}$	Volume of gas flared, by gas type **i**.	m^3	M	Continuous	Gas volume shall be metered at the flare. Gas volume shall be measured at standard conditions.
$Flare\ Fuel_{j,t}$	Volume of each supplemental fuel, by fuel type **j** used to	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

PARAMETER	DESCRIPTION	UNITS	TYPE[54]	MEASUREMENT FREQUENCY	REQUIREMENTS
	ensure complete combustion of the gases.				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**.	decimal fraction	M	Continuous or monthly	Measured using gas chromatograph.
$\%CH_{4_t}$	Concentration of CH_4 in the gas stream that is being flared.	$\%CH_4$ 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 this segment.	e.g., MWh	M, O, C	Continuous or monthly	Continuous measurement of electricity consumption or monthly billing records from utility supplier, or r. See $Electrical\ Rating_{i,t}$, $Hours_{i,t}$, and

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
					$Load_{i,t}$ 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 this segment.	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.
$N_{Blowdown_{i,t}}$	Number of blowdowns (venting events) **i** from all injection, storage and monitoring segment equipment.	#	O, C	As occurs	Transport operators shall keep detailed logs of all venting incidents. This term does not apply to CO_2 transported via CO_2 pipelines used by multiple parties.
$V_{Blowdown_{i,t}}$	Total volume of blowdown equipment chambers for equipment **i** (including pipelines, manifolds, and vessels between isolation	m^3	O, C	N/A	Volume can be estimated based on equipment specifications (e.g., pipeline diameters), flow meters, duration of event. This term does not apply to CO_2 transported via CO_2 pipelines used by multiple parties.

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
	valves) associated with this segment.				
$\%GHG_{j,t}$	Concentration of GHG (CO_2 or CH_4) in vented fuel **j**.	%GHG by volume, expressed as a decimal	M	Monthly	Measurement of the gas stream composition at the venting location. This term does not apply to CO_2 transported via CO_2 pipelines used by multiple parties.
$Count_{s,seg,t}$	Total number of each type of fugitive emission source **s** in project segment **seg** (injection, storage, monitoring and oil production and processing).	#	O, C	N/A	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.
$T_{s,seg,t}$	Total time that the equipment associated with fugitive emission source **s** in segment **seg** (injection, storage, monitoring and oil	hours	M, O, C	N/A	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.

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
	production and processing) was operational.				
$\%GHG_{j,s,t}$	Concentration of GHG (CO_2 and CH_4) in fugitive emission source **s** in this segment.	%GHG by volume, expressed as a decimal	M	Monthly	Direct measurement of the composition of the gas stream.
$Mass_{Injected_{w,g,t}}$	Mass of CO_2 injected into injection well **w** in geologic storage reservoir **g**.	MT	M	Continuous	Metered at each point of injection into the storage reservoir.
CO_2-EOR OPERATIONS (SUBSET OF INJECTION, STORAGE, MONITORING & OIL PRODUCTION AND 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.	m^3, scf	M	Continuous	Continuous metering of sales volumes of hydrocarbon gas produced from the storage reservoir. This excludes CO_2 transported outside of the project boundary that is accounted for under other equations (e.g., Equation 19).
$\%CO_{2\ Hydrocarbon\ Gas_{g,t}}$	Concentration of CO_2 in hydrocarbon gas produced from geologic storage reservoir **g** that is sold or	% CO_2 by volume, expressed as a decimal	M	Continuous or monthly	Direct measurement of the composition of the gas stream.

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
	otherwise transported outside the project boundary.				
$Mass_{Water\ Prod_{g,t}}$	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.	MT	M, O	Continuous or monthly	Monthly reconciliation of water disposal records. Equation 23 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	M, O	Once per reporting period	Lab analysis of the composition of produced water including quantification of dissolved inorganic carbon species.
$Mass_{Oil\ Prod_{g,t}}$	Mass of crude oil and other liquid hydrocarbons produced from geologic storage reservoir **g**.	MT	M, O	Continuous or monthly	Mass shall be metered at the point of transfer offsite or through reconciliation of crude oil sales from facilities associated with the producing formation.

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
$\text{Mass Frac}_{CO_2 \text{ in Oil Prod}_{g,t}}$	Mass fraction of CO_2 in the crude oil and other liquid hydrocarbons produced from geologic storage reservoir **g**.	decimal fraction	M, O	Once per reporting period	Lab analysis of the composition of crude oil and other liquid hydrocarbons.
$\text{Mass Frac}_{\text{Vented } CH_4 \text{ in Water Prod}_{g,t}}$	Mass fraction of CH_4 in the water produced from geologic storage reservoir **g** that is vented to the atmosphere.	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** that is vented to the atmosphere.	decimal fraction	M, O	Once per reporting period	Lab analysis of the composition of crude oil and other liquid hydrocarbons including quantification of methane.
$\text{Vol. Crude}_{g,t}$	Volume of crude oil and associated hydrocarbons produced from geologic storage reservoir **g**.	bbl	M	Continuous	Metered immediately before custody transfer to another entity and shipment offsite of the CO_2 storage location.
ρCrude_g	Density of crude oil produced from geologic storage reservoir **g**.	kg/m^3	M	Monthly	Measured at standard conditions of the density of crude at the site of production.

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
CONSTRUCTION AND POST-INJECTION PERIOD MONITORING, DECOMMISSIONING & CLOSURE SEGMENTS					
$Mass\ Product_{prod,p\ or\ q\ or\ r,t}$	Mass of product **prod** transported for construction, delivery of project product, or for post-injection operations, via means of transport **p** (single-use pipeline) *or* **q** (multiple-user pipeline) *or* **r** (mobile means of transport).	MT	M	Continuous	Metered continuously at the start and end of the transportation segment.
$Distance_{prod,p\ or\ q\ or\ r,t}$	Distance that product **prod** traveled for construction, delivery of project product, or for post-injection operations, via means of transport **p**, **q**, or **r**.	miles	M, O, C	Continuous.	Distance of travel shall be logged and tracked per shipment.
$Fuel_{eq,i,t}$	Volume or mass of fuel type **i** used to operate construction and post-injection operations equipment **eq**.	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

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
					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 during construction and post-injection operations, by gas type **i**.	m^3	M	Continuous	Gas volume shall be metered at the flare. Gas volume shall be measured at standard conditions.
$Flare\ Fuel_{j,t}$	Volume of each supplemental fuel, by fuel type **j** used to ensure complete combustion of the gases during construction and post-injection operations.	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 [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
	carbon-containing gas in gas mixture **i** during construction and post-injection operations.				
$\%CH_{4_t}$	Concentration of CH_4 in the gas stream that is being flared during construction and post-injection operations.	$\%CH_4$ 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 during construction and post-injection operations equipment.	e.g., MWh	M, O	Continuous or monthly	Continuous measurement of electricity consumption or monthly billing records from utility supplier, or r. 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 construction and	MMBtu	M, O	Daily or monthly	Measured daily using a utility meter or measured monthly via invoices from

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
	post-injection operations equipment.				the thermal energy provider showing the quantity of thermal energy supplied.
$Mass_{m_t}$	Mass or weight of material **m** utilized in the project.	e.g., kg, g, lb.	M	Once per crediting period	Measure the total mass of each of the materials used in the construction of the project facilities as listed in Table 6 from the start of construction to the project in-service date.
GEOLOGIC STORAGE RESERVOIR SEGMENT					
CO_{2_z}	Total mass of CO_2 emitted through escape pathway **z** in geologic storage reservoir **g**.	$MTCO_2$	O, C	N/A	If emissions from the geologic reservoir to the atmosphere occur, the mass of CO_2 that has escaped would be estimated 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.

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
ALTERNATIVE QUANTIFICATION METHODS (SEE APPENDIX C)					
$Q_{x,t}$	Mass flow through meter **x**.	MT	M	Continuous	Measured at the same point noted volume parameter above for which mass is replacing volume.
$C_{CO_{2}t}$	CO_2 concentration measurement in flow meter **x.**	% CO_2 by weight, expressed as decimal	M	Continuous	Measured immediately downstream of $Q_{x,t}$.
$\text{Electrical Rating}_{i,t}$	Electrical rating for equipment **i** used in the relevant segment (e.g., capture, processing, and compression; transport) of the CCS project.	MW	O, C	Once per crediting period	Electrical rating for equipment based on manufacturer-provided equipment specifications.
$\text{Hours}_{i,t}$	Operating hours for each piece of equipment **i** that uses electricity.	hours	M, O, C	Continuous or monthly	Estimated (with estimate reasoning documented) or assumed to be equal to the number of hours in the reporting period for conservativeness.

PARAMETER	DESCRIPTION	UNITS	TYPE [54]	MEASUREMENT FREQUENCY	REQUIREMENTS
$Load_{i,t}$	Percent loading of each piece of equipment **i** that uses electricity.	unitless	M	Continuous	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 the requirements contained in U.S. EPA's GHG Reporting Regulation Subpart RR (specifically, 40 CFR 98.444; U.S. EPA, 2025d) 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, 2025c).

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, with the check occurring no more than two months before the end date of the reporting period; 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 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 lower of the two emission reduction estimates shall be reported as the scaled emission reduction estimate.

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 Part 98.3(i)) (U.S. EPA, 2010).

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 G.

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, 2025e; U.S. EPA, 2025d), 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 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 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 whether the MRV Plan has been formally reviewed and approved by a competent jurisdictional authority with regulatory oversight of CO_2 injection and storage, in accordance with ACR CCS Methodology and ACR Standard requirements. This includes 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 independent professional at the time of initial validation —either subcontracted by the VVB or by the Project Proponent. 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 & PLAN INFORMATION

The following requirements follow U.S. EPA UIC Regulation § 146.82 (Required Class VI permit information; U.S. EPA, 2025e). 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 6.2.6.

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 relatively 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, 2025e). 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, 2025e). 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:

I. 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 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.
II. 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
III. 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:

I. Reevaluate the area of review in the same manner specified in section 7.3.5.I.;
II. Identify all wells in the reevaluated area of review that require corrective action.;
III. Perform corrective action on wells requiring corrective action in the reevaluated area of review; and
IV. 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, 2025e). 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 for the life of the project. 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[56] 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.

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:

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

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, 2025e). 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):

I. Fracture pressure,
II. Other physical and chemical characteristics of the injection and confining zone(s), and
III. 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):

I. A pressure fall-off test and
II. A pump test or
III. 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, 2025e). 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 State territorial 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, 2025e). 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, 2025e). 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 7.4.2.1.;
   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, 2025e). 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 Project Term to assure no emission of CO_2 to the atmosphere. The absence of emission of CO_2 to the atmosphere during the Project Term is considered assured when it can be verified that plume stabilization has been achieved, which occurs when there has been no detected migration of CO_2 across the vertical and lateral boundaries of the confining zone and the modeled scenarios indicate that the CO_2 will remain contained within the geologic storage reservoir. 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.

The minimum post-injection monitoring period for CCS projects is five (5) years. During this period, subsurface pressure shall be recorded and changes in pressure measurements 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.

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, 2025e). 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 notify ACR in writing at least 120 days before site closure. 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.

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:

I. Documentation of appropriate injection and monitoring well plugging as specified in Section 7.3.11;
II. A copy of a survey plat which indicates the location of the injection well relative to permanently surveyed benchmarks;
III. 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
IV. 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, 2025e). 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

CCS projects may influence environmental and community conditions, including water and air quality, climate, and ecosystem and human health. These impacts may extend to nearby communities through changes in land use, economic activity, or local well-being (e.g., job creation, infrastructure development, and public health).

ACR requires Project Proponents to conduct a comprehensive assessment of potential environmental and community impacts—both positive and negative—and to demonstrate that the project delivers net benefits and includes adequate mitigation measures for any adverse effects. This assessment must be site-specific, based on best available information, and supported by meaningful engagement with affected stakeholders and communities. The community impacts assessment shall include a public participation process which includes stakeholder engagement, public notices, and comment periods.

Project Proponents shall provide a mitigation plan within the GHG Project Plan that outlines how any foreseeable negative community or environmental impacts will be addressed. Furthermore, Project Proponents must disclose in their annual Attestations any negative environmental or community impacts that occurred or were alleged during the reporting period. This includes any legal actions, formal complaints, or written claims made by affected parties.

8 Ownership and Injection & Storage Site Access

8.1 Statement of Direct Emissions

The Project Proponent shall attest annually that all emission reductions occur on the property owned and/or controlled by the Project Proponents and that none of the emission reductions claimed by the project are indirect emissions.

8.2 Offset Title

Since CCS projects involve capture, transport, and storage processes, which can be conducted by different companies, the ownership to the title of CO_2 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 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 the capture, transport, and storage processes shall be established. This includes documents indicating the date (day, month, and year), CO_2 volumes transferred by the supplier, transported, and received by the CO_2 injection and storage site operator. 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.

8.3 Pore Space Ownership

CCS Project Proponents may need to own or obtain rights to the subsurface pore space where CO_2 will be injected and sequestered. Project Proponents, third party verifiers, and ACR must have access to the site throughout the project lifetime including post-injection monitoring. The Project Proponent must also demonstrate that the CO_2 in the reservoir will be left undisturbed in perpetuity. CCS Project Proponents may need to own or obtain rights to the subsurface pore space where CO_2 will be injected and sequestered. In the U.S., with the exception of federal lands, the acquisition of storage rights, which are considered property rights, is generally a function of state law. In many states, no clear property right to use pore space has been assigned to surface property owners covering the permanent injection of fluids into deep geological formations. Such injection under the Class II UIC program can occur without approval from surface landowners except for those on whose property the injection well is located. These projects appear to have adopted the "inverse rule of capture" rule that allows project owners to be held non-liable if their injected fluids trespass into the subsurface of neighboring properties as long as their injection was in accordance with a federal or state-approved program. In effect, the subsurface rights vest in whomever can assert them physically on a first-come basis (Carnegie Mellon University, 2009).

While pore space ownership issues are beginning to be addressed in the U.S. through state laws and regulations, those rules are not uniform. In the case of storage in non-EOR projects, some states—including Montana, Wyoming, and North Dakota—have assigned pore space ownership to the surface owners. In Wyoming and Montana, pore space ownership may be severed and assigned to the mineral owner. In Texas, mineral rights are severed from surface rights and there is no clear ownership of pore space between surface and mineral owners—although it is likely that pore space is owned by surface owners. In cases where mineral rights are severed from surface rights, it is likely that project proponents will need agreements with both parties to inject CO_2.

In the case of CO_2-EOR projects, the right to inject CO_2 into the subsurface oil reservoir is usually contained in and part of the oil and gas lease that would have been obtained to develop the project. Therefore, the right to use an oil reservoir for the associated storage of CO_2 during the operational phase of a CO_2-EOR project would most likely be permissible under an oil and gas lease. Once injected and secured in the reservoir, the operator is not required to extract the injected CO_2 at the completion of the operational phase of the project.

Migration of any injected fluid is only permissible provided the migration complies with regulations covering injection operations, does not interfere with preexisting mineral recovery operations, cause damage to any adjacent subsurface and overlying surface properties, or endanger public health and safety.

Further, Project Proponents shall obtain the consent of surface owners before they file a Risk Mitigation Covenant (Section 9.3), or they shall provide an alternative risk mitigation assurance acceptable to ACR. Such consent must be verifiable.

8.4 Site Access

Project Proponents, third party verifiers, and ACR must have access to the site throughout the Project Term including post-injection monitoring. All projects must demonstrate their right or permission to access the site and reservoir to conduct all monitoring 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 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. 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. Based on the site-specific monitoring planned for the post-injection period and associated surface access requirements, Project Proponents shall obtain needed surface use rights from the surface owners for the duration of the Project Term. This will usually entail surface use agreements similar to what is currently used to conduct groundwater sampling and remediation activities.

9 Permanence, Reversal Risk Mitigation & Compensation

For CCS projects, Project Proponents must demonstrate that the CO_2 captured and stored is permanently stored underground. The post-injection monitoring tasks described in Section 7.3.12 will be conducted for the Project Term defined in Section 4.3.4. Site characterization coupled with the use of site-specific monitoring and modeling of the AoR provides data and information for the operator to calibrate, validate and compare the model over the Project Term. This model will be used as a predictive tool to monitor and track the CO_2 plume during the post-injection period and beyond. The predictions will be confirmed by measurements of pressure and/or other relevant parameters made during the remainder of the Project Term (post-injection phase). As indicated in Section 7.3.12, plume stabilization is assured when it can be verified that no migration of injected CO_2 is detected across the boundaries of the storage volume and the modeled failure scenarios all indicate that the CO_2 will remain within the storage volume.

An operator shall prove financial responsibility prior to gaining a permit to begin active CO_2 injection operations. This effort establishes a plan for safe operation of injection activities. Implementation of this safety plan throughout operations should mitigate long-term liabilities. Pore space ownership laws may vary by jurisdiction. Project Proponents are responsible for demonstrating that they are compliant with all local rules and regulations related to liability and pore space.

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. Over time, project uncertainties can be greatly reduced through a well-designed monitoring program. As uncertainties are addressed and reduced, confidence in the location of CO_2 plume in the reservoir increases over years of MRV operations. Migration of CO_2 plumes might qualify as trespass or nuisance under State law. The oil industry has addressed this liability during EOR, and the issue of trespass has been addressed in a Texas case (Railroad Commission of Texas v. Manziel, 1962), which held that injection associated with a state-authorized secondary recovery project would not cause trespass even though fluids move across property lines. In other jurisdictions, this issue would be dependent on individual State regulations and statutes. While the lateral migration of CO_2 outside the original project boundaries could indicate that modifications to the project's MRV are necessary, these events should not disqualify or affect the project's emission reductions as long as there are not emissions to the atmosphere.

9.1 Reversals

Each reporting period, the Project Proponent shall deposit a percent of the project's issued ERTs in the ACR-managed Reserve Account as determined by the ACR CCS Reversal Risk Tool. To provide flexibility, contributions to the Reserve Account need not come from the project itself whose risk is being mitigated. A Project Proponent may make its contribution in ERTs of any type other than the Agriculture, Forestry and Other Land Use (AFOLU) sector. The vintage of carbon credits deposited to the Reserve Account is limited to no more than five (5) years prior to the vintage of the carbon credits being verified and issued (e.g., if a Reserve Account deposit is for the issuance of 2025 vintage credits, the earliest vintage of credits that can be deposited is 2020). In the event of reversals, a debit shall be measured and reported, verified, and reconciled by cancelling ERTs from the Reserve Account. As long as carbon credits deposited by a Project Proponent are retained in the Reserve Account, neither the Project Proponent nor Project Developer Account Holder, if not the same entity, may transfer, sell, pledge, retire, or otherwise transact or dispose of such carbon credits. In lieu of making a Reserve Account Contribution, Project Proponents may propose an established insurance product for ACR approval as an alternative reversal risk mitigation mechanism in accordance with the ACR Standard.

If a release of CO_2 from the geologic storage reservoir occurs at any time, the Project Proponent shall notify the appropriate jurisdictional authority and ACR within twenty-four (24) hours, 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 6.2.6) and compensated. The procedures for reversal risk mitigation and compensation of emissions of CO_2 from the geologic storage reservoir during the injection, post-injection, and post-Project Term periods are summarized in Table 8. If a release occurs during the injection period and results in less than the estimated ERs for the current reporting period, then it shall be mitigated as project emissions in the same reporting period using Equation 32 If the release exceeds the estimated ERs for that reporting period, then a portion of that release is mitigated as project emissions until ERs for that reporting period are zero.

Any remaining unreconciled quantity (i.e., a reversal higher than the estimated ERs for that reporting period or estimated ERs are not unrealized) shall be reconciled through the cancellation of an equivalent quantity of ERTs from the ACR Reserve Account. If the reversal quantity exceeds the quantity of ERTs previously deposited by the project and held in the ERT Reserve Account, the Project Proponent shall deposit additional ERTs in the quantity of the shortfall within 45 days of the release (or within 45 days of the submission of the verification to ACR in the event that the reporting period did not result in a sufficient quantity of ERs as estimated). ERTs deposited to compensate for the unreconciled quantity must align with the credit characteristics required for a Reserve Account deposit. If the Project Proponent is not the same entity as the Project Developer Account Holder, the Project Developer Account Holder shall facilitate the deposit of credits on behalf of the Project Proponent to compensate for the reversal.

Table 8: Reversal Risk Mitigation & Compensation Procedures

EMISSIONS SUBJECT TO RESERVE ACCOUNT DEBITS OR OTHER COMPENSATION	REVERSAL RISK MITIGATION & COMPENSATION PROCEDURES
PROJECT TERM INJECTION PERIOD[57]	
N/A	Upon each reporting period issuance, contribute a quantity of eligible credits equivalent to the determined % into the ACR Reserve Account.
Emissions detected during reporting period **t**	Handle as project emissions in the current reporting period **t** using Equation 32. If emissions exceed reporting period **t** ERRs, ACR will cancel the unreconciled quantity to be mitigated from the ACR Reserve Account.
PROJECT TERM POST-INJECTION PERIOD	
Emissions detected past the Crediting Period	ACR will cancel the quantity to be mitigated from the ACR Reserve Account.
Emissions from monitoring, decommissioning & site closure[58]	ACR will cancel the quantity to be mitigated from the ACR Reserve Account.
CCS project has chosen to account for pre-Crediting Period construction emissions over the full Crediting Period but does not complete the full Crediting Period.	ACR will cancel the quantity of pre-Crediting Period construction project emissions to be mitigated from the ACR Reserve Account.

[57] Also known as the Crediting Period.

[58] See Equation 29.

EMISSIONS SUBJECT TO RESERVE ACCOUNT DEBITS OR OTHER COMPENSATION	REVERSAL RISK MITIGATION & COMPENSATION PROCEDURES
POST-PROJECT TERM	
A release of stored CO_2 that is intentional or that is a collateral effect of planned activities that affect the storage volume	Per the Risk Mitigation Covenant or an alternative reversal risk mitigation assurance approved by ACR, prior to any release of stored CO_2 as described in the Covenant, ACR must be compensated through replacement deposit of the full amount of ERTs issued to the project during the Project Term, allowing ACR to cancel such ERTs.

9.2 ACR Reserve Account

Each reporting period, the Project Proponent shall deposit a percent of the project's issued ERTs in the ACR-managed Reserve Account as determined by the ACR CCS Reversal Risk Tool. To provide flexibility, contributions to the Reserve Account need not come from the project itself whose risk is being mitigated. A Project Proponent may make its contribution in ERTs of any type other than the Agriculture, Forestry and Other Land Use (AFOLU) sector. The vintage of carbon credits deposited to the Reserve Account is limited to no more than five (5) years prior to the vintage of the carbon credits being verified and issued (e.g., if a Reserve Account deposit is for the issuance of 2025 vintage credits, the earliest vintage of credits that can be deposited is 2020). As long as carbon credits deposited by a Project Proponent are retained in the Reserve Account, neither the Project Proponent nor Project Developer Account Holder, if not the same entity, may transfer, sell, pledge, retire, or otherwise transact or dispose of such carbon credits. In the event of reversals, a debit shall be measured and reported, verified, and reconciled by cancelling ERTs from the Reserve Account. In lieu of making a Reserve Account Contribution, Project Proponents may propose an established insurance product for ACR approval as an alternative reversal risk mitigation mechanism in accordance with the ACR Standard.

If a release occurs during the injection period and results in less than the estimated ERRs for the current reporting period, then it shall be mitigated as project emissions in the same reporting period using Equation 32. If the release exceeds the estimated ERRs for that reporting period, then a portion of that release is mitigated as project emissions until ERRs for that reporting period are zero. Any remaining unreconciled quantity (i.e., a reversal higher than the estimated ERRs for that reporting period or estimated ERRs are not unrealized) shall be compensated by the cancellation of an equivalent quantity of ERTs from the ACR Reserve Account. If the reversal quantity exceeds the quantity of ERTs previously deposited by the project and held in the ERT Reserve Account, the Project

Proponent shall deposit additional ERTs in the quantity of the shortfall within 45 days of the release (or within 45 days of the submission of the verification to ACR in the event that the reporting period did not result in a sufficient quantity of ERRs as estimated). ERTs deposited to compensate for the unreconciled quantity must align with the credit characteristics required for a Reserve Account deposit. If the Project Proponent is not the same entity as the Project Developer Account Holder, the Project Developer Account Holder shall facilitate the deposit of credits on behalf of the Project Proponent to compensate for the reversal.

The Reserve Account shall also be debited for the balance of any amortized pre-Crediting Period construction emissions in the event that the project does not complete its full Crediting Period or post-injection period emissions associated with monitoring, decommissioning, or closure that are not accounted for in the project emissions in the associated reporting period in which they occur or if they occur after the project term.

9.3 Risk Mitigation Covenant

Prior to the start of injection, the Project Proponent shall file and, if the Project Proponent is not the owner of the pore space comprising and/or surface interests overlying the CO_2 storage volume, cause to be filed by the owners thereof, a Risk Mitigation Covenant in the real property records of each county, parish, and other governmental subdivision that maintains real property records showing ownership of and encumbrances on real property in the jurisdictions in which the CO_2 storage volume (geologic storage reservoir) is located. The Risk Mitigation Covenant shall apply to any activity occurring on the surface or in the subsurface, shall run with the land (including both the surface and subsurface interests), and shall be in a form approved by ACR. Further, the Risk Mitigation Covenant shall prohibit any activity that may result in the release of the stored CO_2 (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 by replacing the reversed ERTs for ACR's retirement pursuant to a plan acceptable to ACR.

To verify compliance with the terms of the Risk Mitigation Covenant, the Risk Mitigation Covenant shall require that the Project Proponent and the owner of the property notify ACR upon discovery of the occurrence of or plans to conduct any activity that may result in a reversal within twenty-four (24) hours and shall require that the Project Proponent and owner of the property submit an annual attestation of compliance to ACR, and shall afford ACR an access right to the property in order to conduct inspections. The obligations under the Risk Mitigation Covenant shall be secured by a lien in favor of ACR against the CO_2 and the pore space comprising the CO_2 storage volume, which lien shall be included in the Risk Mitigation Covenant. The Risk Mitigation Covenant does not restrict activities on the surface that do not result in the potential release of the stored CO_2. In the event that the Project Proponent is not the owner of the pore space comprising and/or surface interests overlying the CO_2

storage volume and is unable to provide the required Risk Mitigation Covenant as part of the demonstration of project eligibility, as an alternative to the Risk Mitigation Covenant ACR may accept (i) proof of the filing of a notice or memorandum of agreement in a form acceptable to ACR in the real property records of each county, parish and other governmental subdivision that maintains real property records showing ownership of and encumbrances on real property in the jurisdictions in which the CO_2 storage volume is located that provides notice of the following terms of the Project Proponent's agreement with such pore space and/or surface interest right owners to any future owners: (a) the agreement that no planned activity shall be conducted that would result in a reversal unless measures are taken in advance to compensate for the reversal by replacing the reversed ERTs for ACR's retirement pursuant to a plan acceptable to ACR (b) the agreement to notify ACR within twenty-four (24) hours upon discovery of the occurrence of a reversal; and (c) a right of access by Project Proponent or its assigns, including ACR, for access to conduct inspections; or (ii) another reversal risk mitigation measure intended to prevent, provide for the discovery of, and compensate for intentional reversals that is acceptable to ACR.

The Risk Mitigation Covenant or alternative risk mitigation assurance shall be approved by ACR and, as applicable, filed in all required jurisdictions, with a copy of the filed documents provided to ACR prior to the issuance of any ERTs for the GHG project..

The obligations of the Project Proponent and any pore space or surface owner under the Risk Mitigation Covenant or alternative reversal risk mitigation assurance shall cease upon demonstration to the reasonable satisfaction of ACR, as evidenced by a written acknowledgement by ACR, that the relevant jurisdictional authority has assumed liability of and monitoring responsibility for the stored CO_2 by the Project Proponent. Any Project Proponent, pore space owner, or surface owner shall be relieved of liability and intentional reversal risk mitigation requirements for any intentional reversal occurring after such government assumption. ACR's written acknowledgement shall be in a recordable form and may be filed in the applicable real property records by the Project Proponent or any pore space or surface owner to evidence the termination of the Risk Mitigation Covenant or alternative reversal risk mitigation assurance.

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.

For aggregated and program design 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 and verifications shall assess the following for conformance to 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 emissions reductions, including the appropriate selection of baseline approach, application of alternative approaches, and use of site-specific emission factors;
- Original underlying data and documentation as relevant and required to evaluate the GHG assertion;
- Data management systems and QA/QC procedures; and
- Roles and responsibilities of participating entities (e.g., Project Proponent, facility owner(s), operator(s), owner(s) of subsurface rights).

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, 2025d) 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.
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 sequestered.
Carbon Dioxide Removal (CDR)	CO_2 removal directly from the atmosphere through biological or technological means, includes direct air capture with CCS (DACCS), the use of sustainable biomass for bioenergy in combination with storage-Bioenergy Carbon Capture and Storage (BECCS), or the use of sustainable biomass in combination with storage -Biomass with Carbon Removal and Storage (BiCRS). To be eligible under this

	methodology, biomass must meet ACR definition of "sustainable" in accordance with Appendix D.
Carbon Dioxide Stream	CO_2 that has been captured from CO_2 capture 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 Capture Source *or* 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	Region 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 hydrocarbons may be produced during the recovery of oil, but this production is incidental to the production of oil.

Excess CO_2 Emissions	CO_2 emissions result from poor or negligent operation of the CO_2 source or CO_2 capture facility, or that occur during periods of non-compliance with technology use and operation regulations; GHG, air pollutant, and toxic air contaminant regulations and other legally enforceable requirements.
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.
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 km² (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, 2025d) 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	A dynamic forest system distinguished by old trees and related structural attributes. Old growth encompasses the later stages of stand development that typically differ from earlier stages in a variety of characteristics, which may include tree size, accumulations of large dead woody material, number of canopy layers, species composition, and ecosystem function. In addition to their ecological attributes, old-growth forests are distinguished by their ecosystem services and social, cultural, and economic values (FSC, n.d.a).
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 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.
Risk Mitigation Covenant	A covenant filed in the real property records of each county, parish and other governmental subdivision that maintains real property records

	showing ownership of and encumbrances on real property in the jurisdictions in which the CO_2 storage volume is located, prohibiting any intentional reversal (e.g., release of stored CO_2 that is intentional or that is a collateral effect of any planned activities affecting the storage volume) unless measures are taken in advance to compensate for the reversal by replacing the reversed ERTs for ACR's retirement pursuant to a plan acceptable to ACR. Refer to Section 9.3.
Saline Reservoir	An underground rock formation typically composed of porous sandstone or carbonate, saturated with saline water (brine), and isolated by an impermeable layer.
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.
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.
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.

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Appendix B: Produced Oil Emission Factors

In addition to accounting for the emissions associated with oil production (refer to Section 6.2.3), emissions from transport, processing and refining, and end use of oil and other hydrocarbons 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. Refer to Table 17 in Section B.5 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 9, 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 $EF_{Hydrocarb-Transpo-Refinery_{g,t}}$ in Equation 31.

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

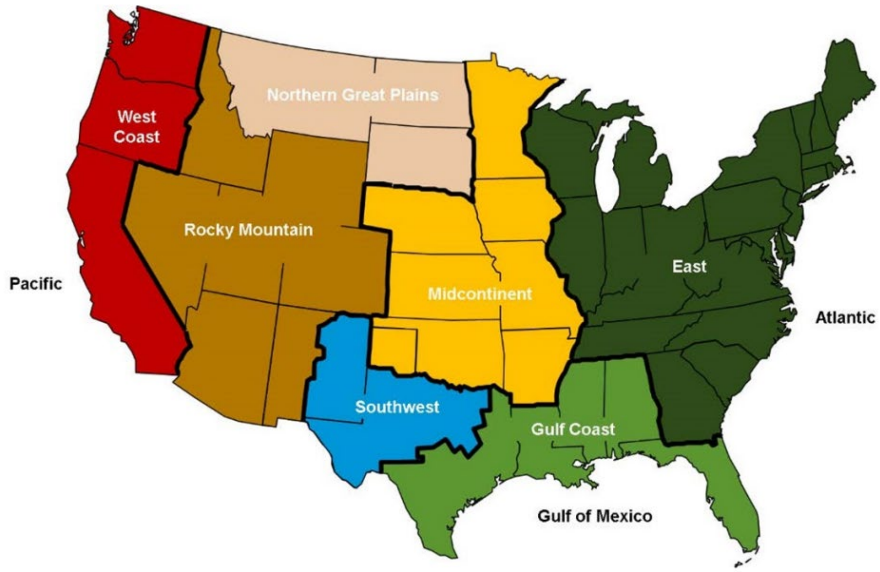


Table 9: Crude Oil Domestic Transport GHG Emissions—from Field to Refinery (Regional Weighted Averages) [59]

	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

[59] This table presumes transport to domestic refining locations. Table 10 accounts for transport of crude oil to refineries outside the U.S.

	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
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

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 [60]	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

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

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 [60]	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
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**			

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 $EF_{Hydrocarb-Crude-Export_{g,t}}$ in Equation 31.

Table 10: 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**

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
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 11, Column 18 default value in red (4.35 CO_2e kg/bbl) for transport emissions from refinery to wholesale terminals. Enter this value into $EF_{Hydrocarb-Transpo-Terminals_{g,t}}$ in Equation 31.

Table 11: 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 12 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 $EF_{Hydrocarb-Transpo-Refined-Export_{g,t}}$ in Equation 31.

Table 12: 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%**

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
"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 API Gravity of crude.

Equation 39: Specific Gravity of Crude

$$SG_{Crude_g} = \frac{\rho Crude_g}{\rho Water_{STP}}$$

WHERE

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

Equation 40: API Gravity Formula [61]

$$\mathbf{APIG_{Crude_g} = \frac{141.5}{SG_{Crude_g}} - 131.5}$$

WHERE

$APIG_{Crude_g}$	API gravity of crude from geologic storage reservoir **g** in reporting period **t** (° API).
SG_{Crude_i}	Specific gravity of crude (unitless).
141.5	Empirical value that standardizes the conversion of specific gravity at 60 °F into degrees API.
131.5	Empirical value that standardizes the conversion of specific gravity at 60 °F into degrees API.

Use Table 13, Column 2 to identify the relevant API gravity. 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 13.

This value is entered into Equation 30 as the term $EF_{Hydrocarb-Refining_{g,t}}$.

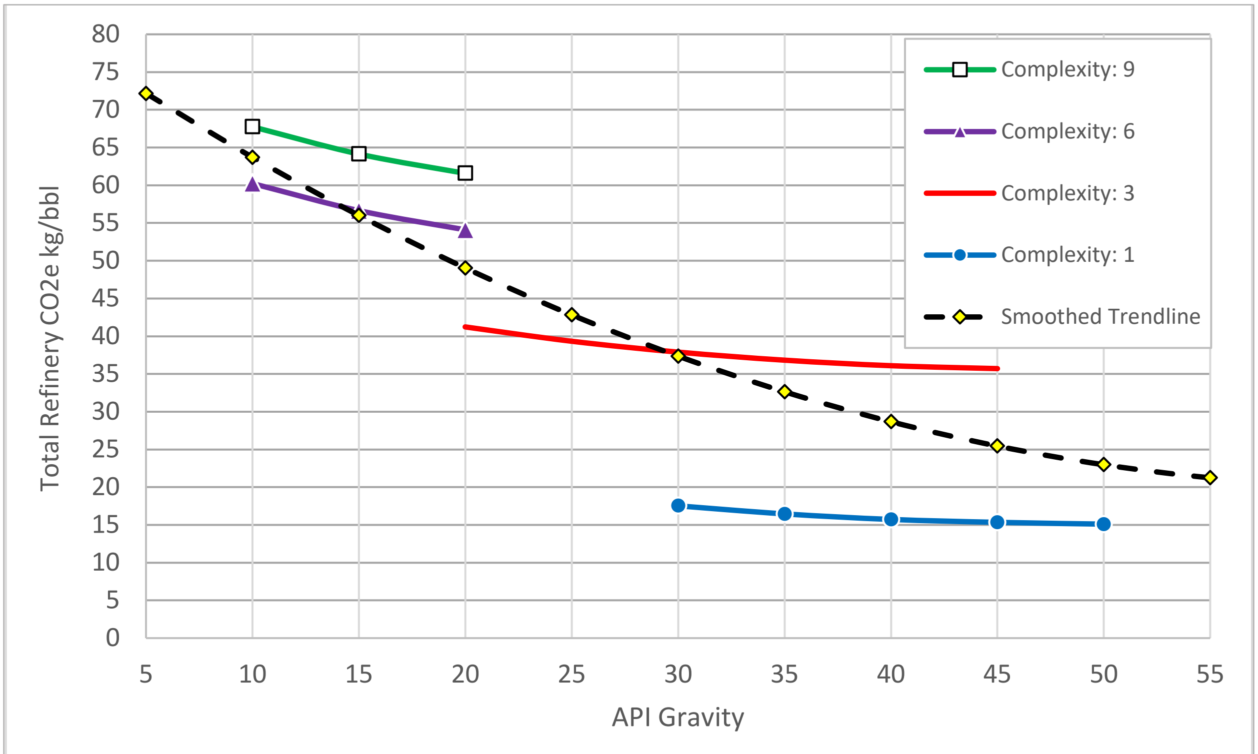
Table 13: Petroleum Product Refining GHG Emissions

1. CLASSIFICATION	2. AVERAGE API GRAVITY OF CRUDE	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%

[61] (API, 2021)

1. CLASSIFICATION	2. AVERAGE API GRAVITY OF CRUDE	3. REFINERY CO_2e KG/BBL (SMOOTHED TRENDLINE)	4. CRUDE INPUTS BY CATEGORY AS % OF ALL U.S. CRUDE INPUTS
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 14, Column 2 to identify the relevant API gravity. Use column 3 in the corresponding row for emissions from combustion and use. Table 15, 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 30 as term $EF_{Hydrocarb-End\ Use_{g,t}}$.

Table 14: 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) [62]	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%**

[62] 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 15: 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 16: 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 9 for the Southwest region)	2.38
B	Transport of crude to foreign refineries (national default from Table 10)	2.21
C	Transport of refined product from refinery to wholesale terminals (Table 11)	4.35
D	Transport of refined product exports (Table 12)	1.51
	The values from Steps A through D are added together and entered into Equation 30 as term $EF_{Hydrocarb-Transpo_t}$.	10.45
E	Refining emissions (Table 13). This value is entered into Equation 30 as term $EF_{Hydrocarb-Refining_t}$.	30.57
F	Product combustion/use (Table 14). This value is entered into Equation 30 as term $EF_{Hydrocarb-End\ Use_t}$..	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 17 may be used as a substitute for Table 9 through Table 12 if a producer knows the specific transportation modes and distances for crude oil or products.

Table 17: 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

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 (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
	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

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)
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.

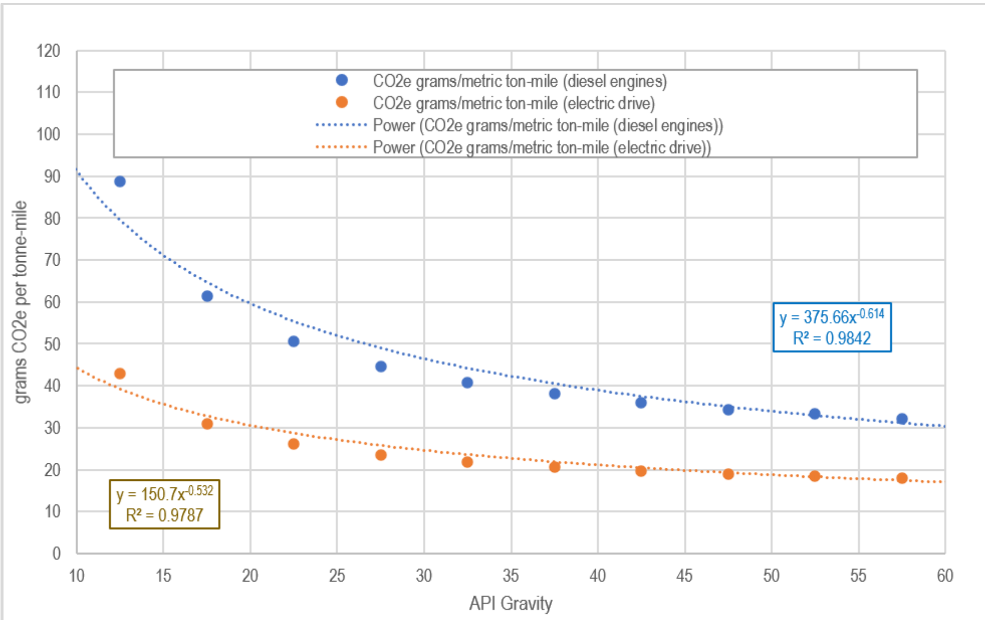
Table 18 and Figure 6 are provided as backup data for some of the other tables presented here that are used for **Step B** or **Step E**. You do not need to use this table or chart to do the required calculations.

Table 18: 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

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)
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.

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

$$CO_{2_t} = \sum_x Q_{x,t} \times C_{CO_{2_t}}$$

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** ($MTCO_2$)
$Q_{x,t}$	Mass flow through meter **x** in reporting period **t** (MT).
$C_{CO_{2_t}}$	CO_2 concentration measurement in flow meter **x** in reporting period **x** (%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 EQ 11, EQ 19, or EQ 27.

Equation 42: Alternative Methodology to Calculate Project Emissions from Electricity Used to Operate Equipment Associated with the CCS Project

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

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 segment (e.g., capture, transport, or storage) of the CCS project in reporting period **t** (MW).
$Hours_{i,t}$	Operating hours for each piece of equipment that uses electricity (hours). Estimated or assumed to be equal to the number of hours in reporting period **t** for conservativeness.
$Load_{i,t}$	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 43: Converting Gas Volumes from Measured Values to Standard Temperature and Pressure (1 atm, 60 °F)

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

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 44 for conversion of °F and °C to Kelvin.

Equation 44: Converting Common Temperatures to Kelvin

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

or

$$Kelvin = °C + 273.15$$

WHERE

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

°C	Temperature in degrees Celsius (°C).

C.4 Fugitive Emissions Sources

Table 19 provides information about potential fugitive emissions sources.

Table 19: Surface Components as Potential Emissions Sources [63]

EMISSIONS SOURCE	ENGINEERING ESTIMATE	EQUIPMENT COUNT AND 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
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

[63] (U.S. EPA, 2025f)

EMISSIONS SOURCE	ENGINEERING ESTIMATE	EQUIPMENT COUNT AND POPULATION FACTOR	REFERENCE IN U.S. EPA GHG REPORTING PROGRAM SUBPART W
CENTRIFUGAL COMPRESSOR WET SEAL OIL DEGASSING VENTING		X	Eq. W-22 through W-25
OTHER EQUIPMENT LEAKS (VALVE, CONNECTOR, OPEN-ENDED LINE, PRESSURE RELIEF VALVE)		X	Eq. W-31

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, 2019). 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, 2019).

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

- Biomass shall be derived from forestry, agriculture, or waste;
- Biomass shall comes from sources located within the U.S. and Canada;
- Biomass must not come from forest conversion, including natural forests converted to monocultural plantations, agriculture or non-forest land uses;
- Biomass must not come from primary forest, intact forest landscapes, old-growth forest or High Conservation Value forests;
- Biomass must come from sources that do not harm workers, Indigenous People or local communities; and
- 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 principles and be eligible to generate credits, ACR requires that projects verify the following, as relevant:

- If the biomass is from waste, verify the source of the waste, date (or range) of delivery, and name of entity delivering waste and confirm that the volumes of biomass used in the Project are appropriate for the specific waste source. Waste includes material that would otherwise have been discarded if the Project did not exist.
- If the biomass is from forest management, verify the following:

  - The biomass maintains Forest Stewardship Council (FSC) certification (FSC MIX or FSC 100%; FSC, n.d.b) 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.
  - Other forest certifications (e.g., Sustainable Forestry Initiative Certified Chain of Custody, SFI, n.d.) may be substituted for FSC if Project Proponents provide, in addition to the certification itself, additional assurance that the principles above have been met.
  - Forest biomass must also maintain Roundtable on Sustainable Biomaterials (RSB) certification (RSB, n.d.).
  - ACR is willing to consider alternative certifications that include independent third-party that the principles above have been achieved. ACR reserves the right to approve or reject these alternatives.
- If the biomass is from agriculture, verify the following:
  - The biomass maintains RSB certification.

Appendix E: CCS-Related Rules and Regulations in the U.S. and Canada

Table 20 through Table 26 outline rules and regulations in the U.S. and Canada that are specific to CO_2 capture, transport, and geologic storage as of fall 2025. This is not meant to be an exhaustive list of all U.S. and Canadian rules and regulations for CCS but provides information on the most important ones.

Table 20: U.S. Federal Rules and Regulations Concerning CCS Projects

TITLE OF DOCUMENT	DESCRIPTION
Federal requirements under the Underground Injection Control (UIC) program for carbon dioxide (CO_2) geologic sequestration (GS) wells 75 FR 77230	Establishes federal requirements for UIC Program for CO_2 geologic sequestration wells by U.S. EPA on permitting and operating CO_2 sequestration wells.
40 CFR - Chapter I: Environmental Protection Agency, Subchapter D: Water Program, Part 144: Underground Injection Control Program	Establishes the framework for U.S. EPA's UIC program, which regulates the construction, operation, permitting, and closure of injection wells. Its purpose is to protect underground sources of drinking water from contamination by injected fluids.
40 CFR - Chapter I: Environmental Protection Agency, Subchapter D: Water Program, Part 145: State UIC Program Requirements	Defines the requirements for states to obtain primacy in administering their own UIC programs in lieu of direct U.S. EPA oversight. It sets standards for program approval, implementation, and enforcement to ensure consistency with federal protections.
40 CFR - Chapter I: Environmental Protection Agency, Subchapter D: Water Program, Part 146: Underground Injection Control Program: Criteria and Standards	Provides detailed technical criteria and performance standards for the six classes of injection wells under the UIC program. These requirements address siting, construction, operation, monitoring, and closure to prevent endangerment of drinking water.

TITLE OF DOCUMENT	DESCRIPTION
40 CFR - Chapter I: Environmental Protection Agency, Subchapter D: Water Program, Part 147: State, Tribal, and EPA-Administered Underground Injection Control Programs	Lists the specific UIC program requirements for each state and tribal authority, as well as U.S. EPA-administered programs where primacy has not been granted. It incorporates individual program descriptions, regulations, and any special provisions.
40 CFR - Chapter I: Environmental Protection Agency, Subchapter D: Water Program, Part 149: Sole Source Aquifers	Establishes U.S. EPA's authority to protect aquifers designated as the sole or principal source of drinking water for an area. It restricts federal funding of projects that may contaminate such aquifers, ensuring safe and reliable drinking water supplies.
49 CFR Part 192 - Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards	Establishes minimum safety standards for natural and other gas pipeline transportation.
49 CFR Part 195 -Transportation of Hazardous Liquids by Pipeline	Sets federal safety standards for the transportation of hazardous liquids or carbon dioxide by pipeline.
30 CFR - Chapter V: Bureau of Ocean Energy Management, Department of the Interior, Subchapter B: Offshore	Regulates offshore leasing and rights to use offshore pore space under the Bureau of Ocean Energy Management.
30 CFR - Chapter II: Bureau of Safety and Environmental Enforcement, Department of the Interior, Subchapter B: Offshore, Part 250: Oil and Gas and Sulphur Operations in the Outer Continental Shelf	Governs well construction, safety, operations, and environmental protection for injection wells on the Outer Continental Shelf.
40 CFR Part 98 - Mandatory Greenhouse Gas Reporting	This regulation establishes mandatory reporting of GHG emissions from specified U.S. facilities and suppliers along with detailed requirements for monitoring, reporting, calculation, calibration, measurement, and recordkeeping.

TITLE OF DOCUMENT	DESCRIPTION
B31.4 - Pipeline Transportation Systems for Liquids and Slurries	ASME B31.4 sets the technical requirements for design, construction, testing, and operation of liquid pipelines, and is federally mandated under 49 CFR Part 195 for hazardous liquid systems, including CO_2 pipelines used in CCS. Compliance is required unless the Pipeline and Hazardous Materials Safety Administration grants a waiver or alternative approval.

Table 21: North Dakota Rules and Regulations Concerning CCS Projects

TITLE OF DOCUMENT	DESCRIPTION
North Dakota Administrative Code - Article 43-05 Geologic Storage of Carbon Dioxide	Sets regulatory framework for geologic storage of CO_2 in North Dakota.
North Dakota Century Code - Chapter 38-25 Underground Storage of Oil and Gas	Governs underground storage of oil and gas in North Dakota.
North Dakota Administrative Code - Chapter 43-02-05 Underground Injection Control	Provides technical and permitting requirements for injection wells in North Dakota.
North Dakota Century Code - Chapter 38-22 Carbon Dioxide Underground Storage	Establishes CO_2 underground storage regulation and jurisdiction in North Dakota.

Table 22: Other U.S. State Rules and Regulations Concerning CCS Projects

STATE	TITLE OF DOCUMENT	DESCRIPTION
Illinois	Illinois Administrative Code - Title 83: Public Utilities, Part 302: Guidelines for Carbon Dioxide Transportation and Sequestration	Provides detailed guidelines for CO_2 transportation and sequestration in Illinois.

STATE	TITLE OF DOCUMENT	DESCRIPTION
Illinois	SAFE CCS Act	Establishes a regulatory framework for capture, transport, and storage of CO_2 in Illinois.
Kansas	General Rules and Regulations For the Conservation of Crude Oil and Natural Gas Disposal and Enhanced Recovery Well Rules	Governs oil and gas production to prevent waste and regulate injection/disposal wells in Kansas.
Texas	Texas Administrative Code - Title 16: Economic Regulation, Part1 Railroad Commission of Texas, Chapter 5: Carbon Dioxide	Provides Texas regulations for carbon dioxide injection and storage.
West Virginia	West Virginia Code - Chapter 22: Environmental Resources, Article 11b: Underground Carbon Dioxide Sequestration and Storage	Establishes legal framework for underground CO_2 sequestration and storage in West Virginia.
Wyoming	SF0047 - Carbon storage and sequestration-liability	Defines long-term liability and stewardship for carbon storage and sequestration projects in Wyoming.

Table 23: Canada Federal Rules and Regulations Concerning CCS Projects

TITLE OF DOCUMENT	DESCRIPTION
Canadian Energy Regulator Onshore Pipeline Regulations	Sets safety, environmental, and technical standards for onshore pipelines in Canada.
Transportation of Dangerous Goods Regulations	Regulates classification, handling, and transport of dangerous goods including CO_2.

TITLE OF DOCUMENT	DESCRIPTION
CSA Z741:12 (R2022) – Geological Storage of Carbon Dioxide	Canadian standard for safe geological storage of CO_2. Required at the provincial level (AB, SK) for CO_2 storage approvals and widely recognized in federal review processes.
CSA Z662:23 – Oil and Gas Pipeline Systems	Establishes technical and safety standards for oil and gas pipeline systems in Canada. Legally mandatory under the Canadian Energy Regulator Onshore Pipeline Regulations and under provincial pipeline regulations for intra-provincial systems.
CSA Z341 SERIES:22-Storage of hydrocarbons in underground formations	Governs storage of hydrocarbons in underground formations. Mandatory for underground hydrocarbon storage projects regulated by the Canadian Energy Regulator and provincial regulators in Alberta, British Columbia, and Saskatchewan.

Table 24: Alberta Rules and Regulations Concerning CCS Projects

TITLE OF DOCUMENT	DESCRIPTION
Mines and Minerals Act	Governs ownership, management, and disposition of mineral resources, ensuring orderly development and royalties.
Directive 008: Surface Casing Depth Requirements	Requires sufficient casing depth to protect groundwater and maintain wellbore integrity.
Directive 009: Casing Cementing Minimum Requirements	Specifies cementing standards to ensure zonal isolation and groundwater protection.
Directive 010: Minimum Casing Design Requirements	Defines minimum casing design standards for well integrity and safe operations.

TITLE OF DOCUMENT	DESCRIPTION
Directive 020: Well Abandonment	Provides procedures for safe and permanent well abandonment and protection of subsurface zones.
Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements	Establishes well classification, design, completion, testing, and monitoring standards for safe injection and disposal.
Directive 056: Energy Development Applications and Schedules	Establishes requirements for project applications, schedules, and regulatory compliance in energy development.
Directive 065: Resources Applications for Oil and Gas Reservoirs	Outlines requirements for applications related to oil and gas reservoir development, approvals, and conservation.
Directive 077: Pipelines – Requirements and Reference Tools	Sets standards for pipeline safety, integrity management, and regulatory compliance.
Pipeline Rule	Provides detailed technical and safety requirements for pipeline operations under the Act.
Oil and Gas Conservation Rules	Governs exploration, development, and production to prevent waste and protect correlative rights.

Table 25: Saskatchewan Rules and Regulations Concerning CCS Projects

TITLE OF DOCUMENT	DESCRIPTION
Oil and Gas Conservation Act	Provides broad regulatory authority for oil and gas resource development and conservation.
Directive PNG005: Casing and Cementing Requirements	Establishes casing and cementing requirements for Saskatchewan wells.
Directive PNG008: Disposal and Injection Well Requirements	Sets requirements for disposal and injection well operations in Saskatchewan.

TITLE OF DOCUMENT	DESCRIPTION
Directive PNG015: Well Abandonment Requirements	Provides rules for safe abandonment of wells in Saskatchewan.
Guideline PNG029: Annulus Test Reporting Requirements	Requires reporting of annulus pressure test results for well integrity monitoring.
Application for an Acid Gas Disposal Project	Outlines information and approvals needed for acid gas disposal projects.
Application for a CO_2 Storage Project (New/Expansion)	Specifies requirements for new or expanded CO_2 storage project applications.

Table 26: Other Canadian Provinces' Rules and Regulations Concerning CCS Projects

PROVINCE	TITLE OF DOCUMENT	DESCRIPTION
British Columbia	Petroleum and Natural Gas Act - Chapter 361	Governs the exploration, development, and production of petroleum and natural gas in British Columbia.
British Columbia	Energy Resource Activities Act - Chapter 36	Provides a regulatory framework for energy resource activities, including oversight and enforcement in British Columbia.
British Columbia	Water Sustainability Act - Groundwater Protection Regulation	Protects groundwater resources through construction, testing, and operational requirements for wells in British Columbia.
Newfoundland and Labrador	Canada-Newfoundland and Labrador Offshore Area Regulations	Regulates offshore oil and gas activities in Newfoundland and Labrador.

Appendix F: 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.

F.1 General Requirements for Emission Factor Selection

All emission factors must satisfy the following criteria:

- Emission factors shall be appropriately applied to the emission source.
- Emission factors shall utilize the appropriate basis of measurement.
- Emission factors shall account for uncertainty, where applicable.
- The Project Proponent shall record units, data source of emission factor, publication year, and all conversion steps.
- Emission factors must be reviewed each reporting period. Updates are required when more current or applicable emission factors or other data becomes available.
- Emission factors must correspond to the time period in which the associated activity occurred, including generation, combustion, procurement, installation, or manufacturing.
- Emission factors must reflect the regional context of production or activity. If location-specific data is unavailable, appropriate adjustments must be applied and justified.

F.2 Emission Factor Sources

Table 28 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 27. 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) [64] *or* power purchase agreement [65]	U.S. EPA eGRID subregion [66]
ELECTRICITY (CANADA)	ECCC emission factors and reference values [67] *or* power purchase agreement [68]	More recent provincial regulatory emission factor with citation
STATIONARY COMBUSTION [69] (U.S. & CANADA) [70]	U.S. EPA 40 CFR Part 98, Subpart C [71] or ECCC emission factors and reference values [72] or WebFIRE Database [73]	IPCC Emissions Factor Database [74]

[64] (U.S. EPA, 2023a)

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

[66] (U.S. EPA, 2023a)

[67] (ECCC, n.d.)

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

[69] 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).

[70] 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).

[71] 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 with capacity ≥ 30 MMBtu/hr under the EPA's Greenhouse Gas Reporting Program (U.S. EPA, 2025b).

[72] (ECCC, n.d.)

[73] (U.S. EPA, n.d.)

[74] (IPCC, n.d.)

SOURCE CATEGORY	TIER 1 (PREFERRED)	TIER 2 (ALTERNATIVE)
MOBILE TRANSPORT (U.S.)	EPA MOVES [75]	R&D GREET [76]
MOBILE TRANSPORT (CANADA)	EPA MOVES [77] with Canada Adjustment or WebFIRE Database [78]	IPCC Emission Factor Database [79]
FUGITIVE EMISSIONS (U.S. & CANADA)	U.S. EPA 40 CFR 98 Subpart W emission factors (Tables W-1A, W-3 through W-6.) [80] Factors must be matched to component type, gas type, and regional context (e.g., eastern vs. western U.S.) [81]	IPCC Emissions Factor Database [82]
CONSTRUCTION MATERIAL PRODUCTION (U.S. & CANADA)	Refer to Table 6.	
PRODUCED HYDROCARBONS (CO_2-EOR ONLY)	Refer to Appendix B.	

[75] (U.S. EPA, 2023b)

[76] (Argonne National Laboratory, 2023)

[77] (U.S. EPA, 2023b)

[78] (U.S. EPA, n.d.)

[79] (IPCC, n.d.)

[80] (U.S. EPA, 2025f)

[81] 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.

[82] (IPCC, n.d.)

F.2.1 ADDITIONAL DETAILS REGARDING ELECTRICITY EMISSION FACTORS

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

- A power purchase agreement (PPA) for the electricity resource with the emission factor being claimed.
- For zero- (or near-zero) GHG emissions electricity sources, the PPA must be for electricity from a newly constructed electricity generator.
- 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.
- For renewable resources, the renewable energy credits associated with the energy used for the CCS project must be retired and evidence of retirement provided.
- Submit a Carbon Capture and Storage Project Emission Factor Justification Form for VVB approval.

F.2.2 ADDITIONAL DETAILS REGARDING TRANSPORT EMISSION FACTORS

- Where applicable, and especially for U.S. EPA MOVES data, emission factors appropriate to vehicle class and model year shall be utilized (U.S. EPA, 2023b).
- 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.
- Distance traveled can be determined by one of the following methods:
  - Recording of vehicle odometer reading before and after completion of trip,
  - 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
  - Other justifiable methods that account for actual operating time or fuel consumption for each equipment or vehicle type.
- 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.
- Use the emission factor for the corresponding mode of transport wherever possible.

- 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:

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

Appendix G: 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 28 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 28 may be applied:

Table 28: 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.

PERIOD OF MISSING DATA	SUBSTITUTION METHODOLOGY
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