



**The American Carbon Registry™**

***Methodology for  
Greenhouse Gas Emission Reductions  
from  
Carbon Capture and Storage Projects***

**Version 1.0**

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### **ABOUT AMERICAN CARBON REGISTRY® (ACR)**

A leading carbon offset program founded in 1996 as the first private voluntary GHG registry in the world, ACR operates in the voluntary and regulated carbon markets. ACR has unparalleled experience in the development of environmentally rigorous, science-based offset methodologies as well as operational experience in the oversight of offset project verification, registration, offset issuance and retirement reporting through its online registry system.

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## DEFINITIONS<sup>1</sup>

*Atmospheric Leakage:* Leakage of injected CO<sub>2</sub> from the geologic storage reservoir to the atmosphere.

*Carbon Capture and Storage (CCS):* The separation and capture of carbon dioxide (CO<sub>2</sub>) from the atmospheric emissions of industrial processes or the *direct air capture (DAC)* of atmospheric CO<sub>2</sub> and the transport and safe, permanent storage of the CO<sub>2</sub> in deep underground geologic formations.

*Confining Zone:* Region in the subsurface above the *Storage Volume* that forms a nearly impenetrable layer to the vertical migration of CO<sub>2</sub>.

*Direct Air Capture (DAC):* Process of separating and capturing CO<sub>2</sub> from the atmosphere.

*Enhanced Oil Recovery (EOR):* The process of producing hydrocarbons from subsurface reservoirs using thermal, gas, or chemical injection techniques. In this methodology, EOR concerns the injection of CO<sub>2</sub> to produce hydrocarbons from the reservoir.

*Emission Reduction Tonne (ERT):* The “ERT” is the ACR unit of exchange for tradable, project-based verified carbon offsets. ERTs refer to both emission reductions and enhancements in sequestration. ACR issues one ERT for each metric tonne of CO<sub>2</sub>e emission reductions or removals verified against an ACR standard and methodology.

*Excess CO<sub>2</sub> Emissions:* Additional CO<sub>2</sub> emissions that could result from poor or negligent operation of the primary process, or from not meeting existing regulations mandating the use of certain technologies, or regulations directly controlling CO<sub>2</sub> emissions or other pollutant emissions which indirectly affect CO<sub>2</sub> emissions. Projects shall not be credited for storage of excess CO<sub>2</sub> emissions.

*Fugitive Emissions:* Emissions due to leaks from equipment such as flanges, valves, flow meters, headers, etc. These emissions can occur in the capture, transport, injection, and storage segments of the project and are calculated using procedures described in Section 4.0.

*Functional Equivalence:* A project and baseline are functionally equivalent if they provide the same function while delivering comparable products in quality and quantity.

*Geologic Storage:* The placement of CO<sub>2</sub> into a subsurface formation, such as an oil and gas producing reservoir or a deep saline aquifer, where it will remain safely and permanently stored.

*Geologic Storage Reservoir:* See *Reservoir*

*Greenhouse Gas (GHG) Assessment Boundary:* The greenhouse gases included in the calculation of baseline and project emissions. In this methodology these include carbon dioxide (CO<sub>2</sub>), methane (CH<sub>4</sub>), and nitrous oxide (N<sub>2</sub>O).

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<sup>1</sup> For additional definitions of standard terms see the latest version of the *ACR Standard*.

*Invalidation:* The voiding of an offset credit by ACR. In the event that and for so long as a Project Proponent has not filed a Risk Mitigation Covenant or provided an alternative risk mitigation assurance acceptable to ACR as described in Section 5.4.1, offset credits issued for the project shall be subject to invalidation by ACR in the event of an intentional reversal for which compensation is not made.

*Monitoring, Reporting, and Verification (MRV) Plan:* A verifiable project-specific plan which includes the monitoring and reporting requirements described in Section 5.4 of this methodology.

*Oil and Gas Reservoir:* See *Reservoir*

*Permanence:* Permanence refers to the perpetual nature of removal enhancements and the risk of reversal of a project's emissions reductions, i.e., the risk that atmospheric benefit will not be permanent. GHG removals may not be permanent if a project has exposure to risk factors, including unintentional reversals (i.e. atmospheric leakage as defined above) and intentional reversals (e.g., release of stored CO<sub>2</sub> that is intentional or that is a collateral effect of any planned activities affecting the storage volume). For CCS projects, the absence of atmospheric leakage during the Project Term is considered assured when it can be verified that no migration of injected CO<sub>2</sub> is detected across the boundaries of the storage volume and the modeled failure scenarios all indicate that the CO<sub>2</sub> will remain contained within the storage volume (see 5.4.1). The risk of intentional reversal is determined by an assurance that the injected CO<sub>2</sub> remains in the storage volume based on the post-injection monitoring strategy and post-Project Term storage requirements described in Section 5.4.

*Physical Boundary:* GHG emission sources included in the project.

*Primary Process:* The specific power generation or industrial process (e.g., natural gas processing, hydrogen production, steelmaking) creating the captured CO<sub>2</sub>.

*Primary Recovery Process:* The production of hydrocarbons from the subsurface without the use of artificial methods, such as water, steam, gas or chemical injection.

*Producing reservoir:* See *Reservoir*.

*Projection-based Baseline:* A baseline that would correspond with the project's actual CO<sub>2</sub> capture site, absent the capture and compression system located at the CO<sub>2</sub> source.

*Reversal:* Atmospheric leakage of injected CO<sub>2</sub> from the *Storage Volume* that is not remediated.

*Reversal Risk Mitigation Mechanism:* Project Proponents shall mitigate reversal risk by contributing offset credits from the project itself to the ACR Reserve Account; contributing ACR offset credits of another type or vintage to the ACR Reserve Account; providing evidence of sufficient insurance coverage with an ACR-approved insurance product to recover any future reversal; or using another ACR-approved risk mitigation mechanism. ACR requires geologic sequestration Project Proponents to use approved methodologies that assure permanence including ongoing QA/QC and long-term monitoring and reversal risk mitigation measures as described in Section 5.4.

*Reservoir:* A three-dimensional confined region in the subsurface that encompasses the region containing hydrocarbons being produced.

*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<sub>2</sub> storage volume is located, prohibiting any intentional reversal (e.g., release of stored CO<sub>2</sub> 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 offset credits for ACR's retirement pursuant to a plan acceptable to ACR. See section 5.4.1.

*Standards-based Baseline:* A baseline represented by a performance or regulatory standard, usually expressed in the form of an intensity metric (e.g., tonnes of CO<sub>2</sub> per megawatt hour of generated electricity).

*Storage Volume:* A space within the subsurface into which the project CO<sub>2</sub> is injected and where the injected CO<sub>2</sub> is stored permanently.

*Venting 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 4.0.

## 1.0 BACKGROUND AND APPLICABILITY

### 1.1 Background on CCS Projects

Carbon capture and storage (CCS) is the separation and capture of carbon dioxide (CO<sub>2</sub>) from the atmospheric emissions of industrial processes or the direct air capture (DAC) of atmospheric CO<sub>2</sub> and the transport and safe, permanent storage of the CO<sub>2</sub> in deep underground geologic formations.<sup>2 3</sup>

In CCS, CO<sub>2</sub> that would otherwise have been emitted into the atmosphere or that currently resides in the atmosphere is captured and disposed of underground. By preventing CO<sub>2</sub> from large-scale industrial facilities from entering the atmosphere or by removing the CO<sub>2</sub> that currently resides in the atmosphere, CCS is a powerful tool for addressing potential climate change. Geologic storage is defined as the placement of CO<sub>2</sub> into a subsurface formation so that it will remain safely and permanently stored. Examples of subsurface formations include deep saline aquifers and oil and gas producing reservoirs.

The CO<sub>2</sub> for geologic storage comes either from industrial facilities that emit large amounts of CO<sub>2</sub>, particularly those that burn coal, oil, or natural gas; or potentially directly from the atmosphere via large-scale chemical DAC facilities. Industrial facilities include power plants, petroleum refineries, oil and gas production facilities, iron and steel mills, cement plants, and various chemical plants.

This methodology outlines the requirements and process for CCS Project Proponents that store CO<sub>2</sub> in oil and gas reservoirs to qualify their projects for carbon credits under the American Carbon Registry® (ACR) program. The methodology is based on the accounting framework developed by the Center for Climate and Energy Solutions (formerly the Pew Center on Global Climate Change).<sup>4</sup>

### 1.2 Eligibility

Eligible projects under the methodology are those that capture, transport and inject anthropogenic CO<sub>2</sub> during enhanced oil recovery (EOR) operations into an oil and gas reservoir located in the US or Canada where it is sequestered. Figure 1-1 provides a basic schematic of a CCS project illustrating the scope of the methodology. A description of EOR is included in Appendix A.

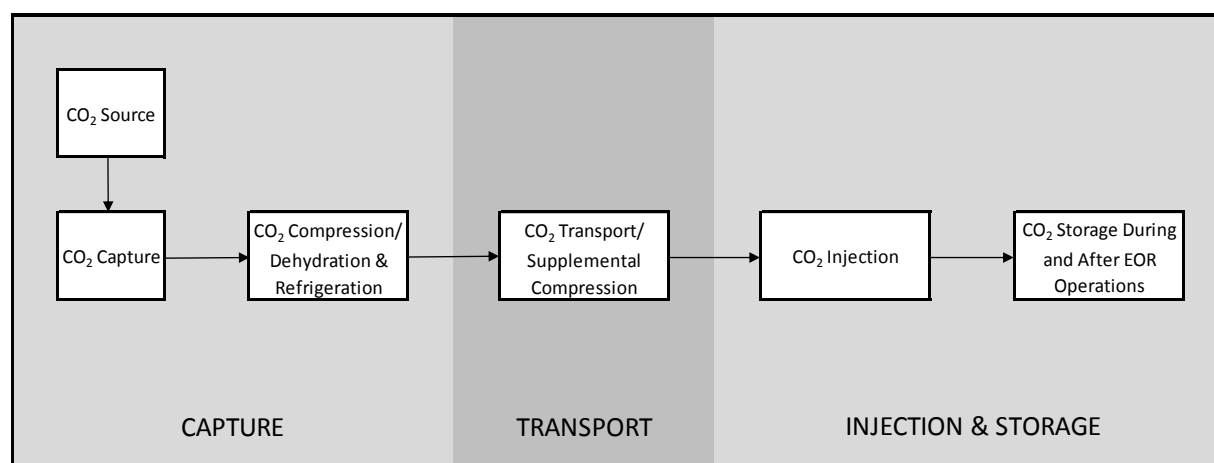
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<sup>2</sup> What is carbon sequestration (or carbon capture and storage)?, [http://www.netl.doe.gov/technologies/carbon\\_seq/FAQs/carbonseq.html](http://www.netl.doe.gov/technologies/carbon_seq/FAQs/carbonseq.html)

<sup>3</sup> The Business of Cooling the Planet, Fortune, October 7, 2011, <http://tech.fortune.cnn.com/2011/10/07/the-business-of-cooling-the-planet/>

<sup>4</sup> A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects, Center for Climate and Energy Solutions, February, 2012





**Figure 1-1** Basic CCS Project Schematic<sup>5</sup>

Projects are only eligible if there is clear and uncontested ownership of the pore space and, unless the Project Proponent has filed a Risk Mitigation Covenant and secured the consent of surface owners to the filing of a Risk Mitigation Covenant or provided an alternative risk mitigation assurance acceptable to ACR as described in 5.4.1, offset credits issued for a project shall be subject to Invalidation. Additionally as described in Section 6.3, Project Proponent and EOR operators shall obtain needed surface use agreements for the duration of the Project Term to conduct post-injection monitoring activities and, if necessary, remediation.

With respect to the capture of CO<sub>2</sub>, eligible CO<sub>2</sub> source types include, but are not limited to: electric power plants equipped with pre-combustion, post-combustion, or oxy-fired technologies; industrial facilities (for example, natural gas production, fertilizer manufacturing, and ethanol production); polygeneration facilities (facilities producing electricity and one or more of other commercial grade byproducts); and DAC facilities.

Eligible CO<sub>2</sub> transport options include moving CO<sub>2</sub> by barge, rail, or truck from the source to the storage field, or moving the CO<sub>2</sub> in a pipeline.

Eligible geological storage of CO<sub>2</sub> for an EOR project must, at minimum, utilize Class II wells in the US and similar well requirements in Canada. Eligible projects include those where CO<sub>2</sub> is injected:

- to enhance production from hydrocarbon producing reservoirs that have previously produced or are currently producing through the use of primary and secondary recovery processes; or
- to produce from reservoirs that have not produced hydrocarbons through the use of primary or secondary recovery processes but have a potential for hydrocarbon recovery through CO<sub>2</sub> injection in the reservoir.

<sup>5</sup> Adapted from A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects, Center for Climate and Energy Solutions, February, 2012

If projects are required to transition from Class II to Class VI wells after project registration, then those projects will remain eligible through the end of the current Crediting Period. In other words, if regulations requiring the transition from Class II to Class VI wells are enacted after the project has been registered with the ACR, then that project will continue to be eligible with Class II wells through the end of the project's current Crediting Period. The eligibility of the project during future Crediting Periods will include an assessment of whether the transition rules require conversion of the project's Class II wells to remain eligible.

### **1.3 Periodic Reviews and Revisions**

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

## 2.0 PROJECT BOUNDARIES

Consistent with *ACR Standard* requirements, the project boundary includes a physical boundary, a temporal boundary, and a greenhouse gas (GHG) assessment boundary. Figure 2-1 provides a general illustration of project boundaries, which includes the physical boundary (i.e. emission sources) and assessment boundary (i.e., the GHGs emissions from each source). In addition, project boundaries include the temporal boundary, which include the temporal parameters affecting project validity and the duration of required project activities. Physical, temporal, and assessment boundaries are discussed in the following sections.

### 2.1 Physical Boundary

The physical boundary demarcates the GHG emission sources included in the project and baseline emissions calculation (as presented in Section 4). In this methodology, the project boundary is intentionally drawn broadly to avoid unaccounted emissions associated with capturing and storing CO<sub>2</sub>. Specifically it covers the full CCS process, including emissions from CO<sub>2</sub> capture, transport, and storage in oil and gas reservoirs, as well as CO<sub>2</sub> recovery and re-injection operations at EOR sites. If CO<sub>2</sub> is captured from more than one process, then the Project Proponent shall combine them within the boundary that encompasses the capture site.

The installation of CO<sub>2</sub> capture may impact one or more emissions sources at a facility, but may also leave unaffected other sources. Therefore, to ensure the emissions reduction 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 project scenarios – i.e., the change in emissions due to capturing CO<sub>2</sub>. This may require the inclusion of one or more emission sources from the Primary Process creating the captured CO<sub>2</sub>. For example, a boundary for CO<sub>2</sub> capture at a hydrogen production unit within a refinery unit would encompass systems associated with the hydrogen production process but might exclude downstream units that use the hydrogen (e.g., the hydro-treating units) or other upstream systems unaffected by the CO<sub>2</sub> capture system.

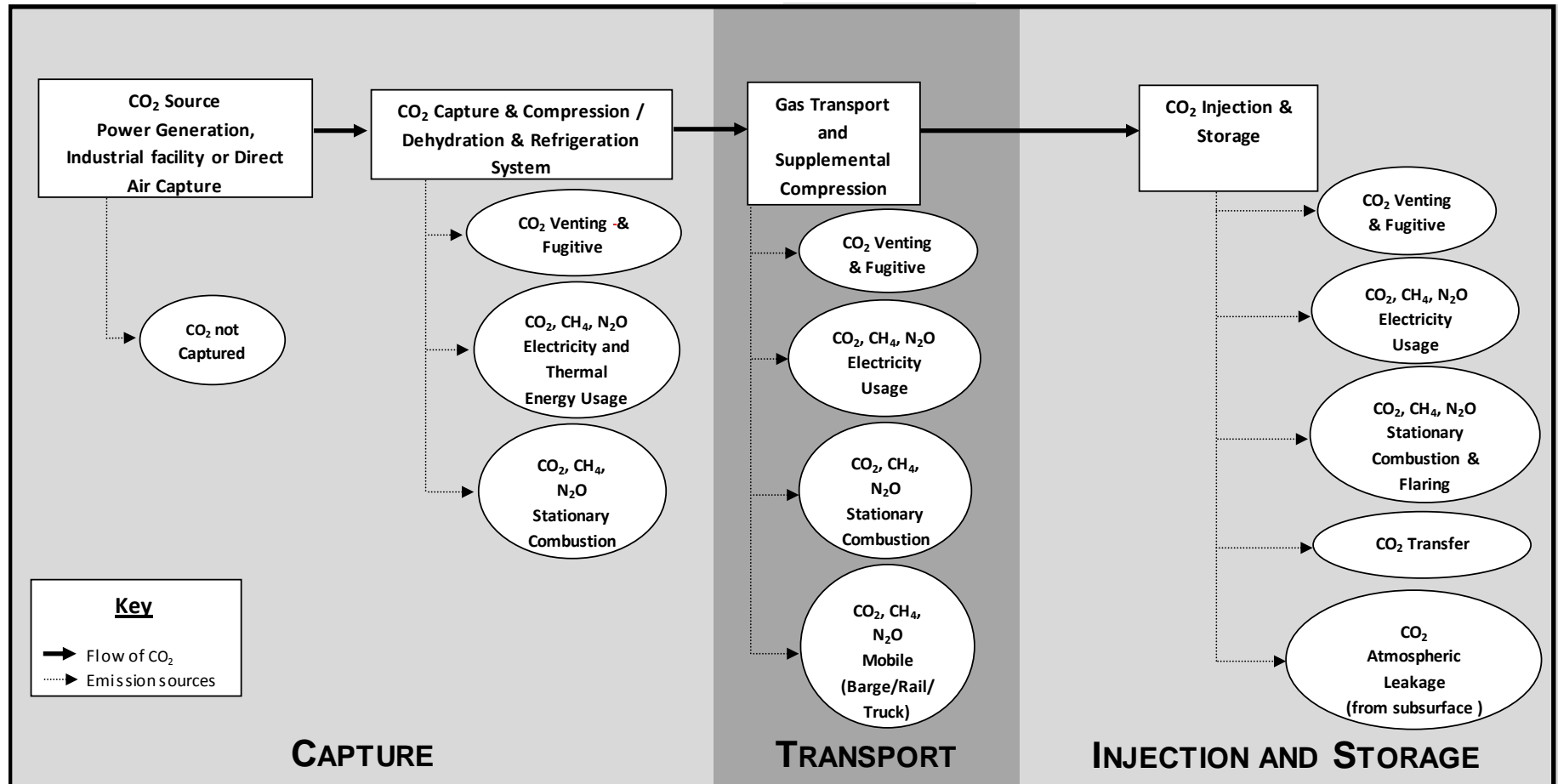


Figure 2-1 CCS Project Boundary<sup>6</sup>

<sup>6</sup> Adapted from A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects, Center for Climate and Energy Solutions, February, 2012

## 2.2 Temporal boundary

For qualifying CCS projects, the project Start Date is January 1, 2000 or the date when the project's captured CO<sub>2</sub> is first injected for sequestration in the subsurface, whichever is later. For CCS projects associated with ongoing EOR operations, the sequestration site may already be utilizing CO<sub>2</sub> from other sources delivered through an existing CO<sub>2</sub> pipeline network (e.g., West Texas). In those situations, the project Start Date is the date when custody of the project's captured CO<sub>2</sub> is first transferred to the EOR operator.

Projects whose Start Date is more than two years prior to the date of listing on ACR must provide documentation that GHG mitigation was an objective as of the Start Date. This documentation must provide evidence, based on official, legal or other corporate documentation that was available to third parties at or prior to the Start Date of the Project Activity, that GHG mitigation and/or the sale or retirement of carbon credits was considered in the decision to proceed with the Project Activity.

Crediting Period is the finite length of time for which a GHG Project Plan is valid, and during which a project can generate offsets against its baseline scenario. Since qualifying CCS projects are usually long-term (30+ years) and involve significant investment in CCS infrastructure as well as for developing individual project and monitoring plans, the Crediting Period for these projects shall be ten (10) years. This period provides an adequate term during which market participants (Project Proponents, offset buyers, registries, etc.) have a level of assurance that offsets will be generated from the project as long as they are successfully verified in accordance with the project's approved GHG Project Plan. At the end of each 10-year period, the Project Proponent may apply to renew the Crediting Period by complying with all then-current ACR requirements, re-evaluating the baseline scenario, and using emission factors, tools and methodologies in effect at the time of Crediting Period renewal. ACR does not limit the allowed number of Crediting Period renewals.

The Project Term is the minimum length of time for which a Project Proponent commits to project continuance, monitoring and verification. For CCS projects the Project Term includes the period of CO<sub>2</sub> injection plus a time period following the end of injection during which the reservoir is monitored for atmospheric leakage. The minimum post-injection period for CCS projects is five (5) years. The duration of post-injection monitoring shall be extended beyond 5 years based on the monitoring results obtained during this 5-year period and whether no leakage of CO<sub>2</sub> (discussed in Section 5.4) can be assured. If no leakage of CO<sub>2</sub> cannot be assured based on the monitoring during this period, the Project Term will be extended in two-year increments until no leakage of CO<sub>2</sub> is assured.

## 2.3 Greenhouse Gas Assessment Boundary

The greenhouse gases included in calculations of baseline emissions and project emissions are shown in Table 2-1. The emissions associated with the combustion of hydrocarbons produced by EOR products (i.e., produced oil or gas), which occurs outside the project boundary at the point of use, are excluded. This approach is consistent with other GHG emission reduction methodologies, where emissions related

to the use of the products are not included. Moreover, oil production through EOR would most likely displace an equivalent quantity of imported oil or in some cases domestic primary (i.e., non-EOR) production.<sup>7,8,9</sup> The methodology encourages the domestic production of oil with a lower carbon footprint due to the simultaneous injection and storage of anthropogenic CO<sub>2</sub> that would otherwise be emitted to the atmosphere.

**Table 2-1 Greenhouse Gases Considered in the Assessment Boundary**

	Emission Source	Gas	Included?	Justification/Explanation
Baseline	Gas stream captured from the primary process	CO <sub>2</sub>	Yes	CO <sub>2</sub> is major emission from source
		CH <sub>4</sub>	No	Emission is negligible and exclusion is conservative
		N <sub>2</sub> O	No	Emission is negligible and exclusion is conservative
Project	<b>CO<sub>2</sub> Capture</b>			
	Non-captured CO <sub>2</sub> from the primary process (vented and fugitive)	CO <sub>2</sub>	Yes	CO <sub>2</sub> is major emission from source
		CH <sub>4</sub>	No	Emission is negligible
		N <sub>2</sub> O	No	Emission is negligible
	Stationary combustion	CO <sub>2</sub>	Yes	CO <sub>2</sub> is major emission from source
		CH <sub>4</sub>	Yes	Included for completeness
		N <sub>2</sub> O	Yes	Included for completeness
	Electricity and thermal energy usage	CO <sub>2</sub>	Yes	CO <sub>2</sub> is major emission from source
		CH <sub>4</sub>	Yes	Included for completeness
		N <sub>2</sub> O	Yes	Included for completeness
	<b>CO<sub>2</sub> Transport</b>			
	Stationary combustion	CO <sub>2</sub>	Yes	CO <sub>2</sub> is major emission from source
		CH <sub>4</sub>	Yes	Included for completeness
		N <sub>2</sub> O	Yes	Included for completeness
	Vented & fugitive emissions	CO <sub>2</sub>	Yes	CO <sub>2</sub> is major emission from source
		CH <sub>4</sub>	No	Emission is negligible
		N <sub>2</sub> O	No	Emission is negligible
	Electricity usage	CO <sub>2</sub>	Yes	CO <sub>2</sub> is major emission from source
		CH <sub>4</sub>	Yes	Included for completeness
		N <sub>2</sub> O	Yes	Included for completeness
	Mobile (Barge/Rail/Truck)	CO <sub>2</sub>	Yes	CO <sub>2</sub> is major emission from source
		CH <sub>4</sub>	Yes	Included for completeness
		N <sub>2</sub> O	Yes	Included for completeness

<sup>7</sup> The most recent Energy Information Agency (EIA) data indicates that in 2011, the US produced 5.65 million barrels per day (MMbbl/d) of crude oil while importing 8.94 MMbbl/d during the same period. So any incremental increase in domestic oil production through EOR would offset an equivalent quantity of imported oil that is produced by primary production processes which do not involve CO<sub>2</sub> sequestration. Therefore there are no incremental emissions associated with the combustion of the produced oil.

<sup>8</sup> Storing CO<sub>2</sub> with Enhanced Oil Recovery, DOE/NETL-402/1312/02-07-08, National Energy Technology Laboratory, February 2008.

<sup>9</sup> Reducing Imported Oil with Comprehensive Climate and Energy Legislation, Natural Resources Defense Council, March 2010.

Emission Source	Gas	Included?	Justification/Explanation
<b>CO<sub>2</sub> Storage</b>			
Stationary combustion	CO <sub>2</sub>	Yes	CO <sub>2</sub> is major emission from source
	CH <sub>4</sub>	Yes	Included for completeness
	N <sub>2</sub> O	Yes	Included for completeness
Vented & fugitive emissions from surface facilities	CO <sub>2</sub>	Yes	CO <sub>2</sub> is major emission from source
	CH <sub>4</sub>	Yes	Included for completeness
	N <sub>2</sub> O	No	Not contained in source emissions
Electricity usage	CO <sub>2</sub>	Yes	CO <sub>2</sub> is major emission from source
	CH <sub>4</sub>	Yes	Included for completeness
	N <sub>2</sub> O	Yes	Included for completeness
Produced gas transferred outside project boundary	CO <sub>2</sub>	Yes	CO <sub>2</sub> is major emission from source
	CH <sub>4</sub>	No	Emission is negligible
	N <sub>2</sub> O	No	Emission is negligible
Atmospheric leakage of CO <sub>2</sub> emissions from the geologic reservoir	CO <sub>2</sub>	Yes	CO <sub>2</sub> is major emission from source
	CH <sub>4</sub>	No	Emission is negligible
	N <sub>2</sub> O	No	Emission is negligible

## 3.0 BASELINE DETERMINATION

### 3.1 Baseline Description

The project baseline is a counterfactual scenario that forecasts the likely stream of emissions or removals that would occur if the Project Proponent does not implement the project, i.e., the "business as usual" case. It serves as a reference case against which to quantitatively compare the GHG emissions associated with the project and derive net emission reductions. In this and other sections of this document the discussions are focused on power plants as an example. CO<sub>2</sub> sourced from other industrial sources and used for EOR equally qualify. Further, there could be more than one source of CO<sub>2</sub> used for EOR by the project.

The methodology presents two baseline options, referred to as Projection-based and Standards-based.

#### 3.1.1 Baseline Options for CCS Projects

A Project Proponent would select the baseline that applies to its project, and then follow the matching calculation procedure. The choice of baseline dictates the equations applied, as provided in Section 4.1.2 and 4.1.3:

Projection-based baseline

Baseline Equation 4.1

Standards-based baseline

Baseline Equation 4.2

Projection-based. This option represents a baseline that would correspond with the project's actual CO<sub>2</sub> capture site, absent the capture and compression system located at the CO<sub>2</sub> source. For example, if the CCS project includes a coal electricity generator with post-combustion capture, a Projection-based baseline would be the coal plant without CO<sub>2</sub> capture; similarly, if the CCS project captures CO<sub>2</sub> from acid-gas removal associated with natural gas production, a Projection-based baseline would be the natural gas production facility with acid gas removal but with CO<sub>2</sub> vented to the atmosphere.

For most CCS projects, the Projection-based baseline scenario will apply. According to the calculation approach, the Project Proponent will determine Projection-based baseline emissions according to actual measured quantities of CO<sub>2</sub> captured from the project, which would have been vented to the atmosphere had the CCS project not been implemented, minus the incremental CO<sub>2</sub> generated at the capture site due to CO<sub>2</sub> capture equipment. The calculation uses data collected in the project condition to represent the quantity of emissions prevented from entering the atmosphere.

Standards-based. The Standards-based baseline can be based on a technology or specified as an intensity metric or performance standard (e.g., tonnes of carbon dioxide equivalent [tCO<sub>2</sub>e] per unit of output). It could correspond with a similar or different technology than the CCS project's actual CO<sub>2</sub> capture site, but which fulfills the same purpose and function. For instance, if the CCS project includes a coal-fired electricity generator with post-combustion capture, a Standards-based baseline could be



represented by a coal-fired or natural gas-fired power plant's emissions rate, expressed as tonnes CO<sub>2</sub>/megawatt hour [MWh]. In this case, baseline emissions would be calculated by multiplying the actual MWhs delivered to the grid in the project condition (net MWh) times the approved emissions rate. In the case of hydrogen production required for refining operations, a steam methane reformer (SMR) hydrogen production facility could be represented in the standards baseline by a catalytic reformer which produces less CO<sub>2</sub> compared to SMR hydrogen production.

A Standards-based baseline is sector specific, at minimum, to ensure reasonable accuracy, and it could have a different emissions profile than the technology used at the CO<sub>2</sub> capture site.

A performance standard could be set by regulation for a particular sector. If the quantity of CO<sub>2</sub> captured and stored exceeds this standard then those excess reductions would qualify under the methodology (assuming other requirements are met). For example, if CCS enabled a new or modified facility to reduce its emissions to 800 lbs/MWh, which exceeds a regulatory performance standard requirement of 1,000 lbs/MWh, then under a performance standard approach, the baseline would be set at 1,000 lbs/MWh (mandated by regulation) and the difference of 200 lbs/MWh would be eligible for credits under the methodology.

If both baseline options are feasible for a given project, the more conservative option (i.e. the option likely to result in a lower estimate of baseline emissions and therefore a lower estimate of net emission reductions) shall be selected unless justification can be presented, acceptable to ACR and the validator, why the less conservative option represents a more credible and likely baseline scenario.

### **3.1.2 Baseline Considerations for Retrofit and New-Build CCS Projects**

Depending on the situation, either the Projection-based or Standards-based baseline could apply to projects that capture CO<sub>2</sub> at power generation or other industrial facilities, and inject CO<sub>2</sub> at various types of storage sites.

Retrofit CCS Projects: Given the limited number of regulations that require GHG emissions reductions from facilities in the U.S., the baseline for most retrofit projects would involve the continued operation of the existing CO<sub>2</sub> source facility, but without carbon capture and storage – such that produced CO<sub>2</sub> is vented to the atmosphere. This corresponds with the Projection-based baseline.

However, if the retrofit involves a major overhaul of technologies, then applying a Projection-based baseline might not be the most reasonable approach. Instead, it may be more appropriate to characterize the baseline in terms of the emissions rate associated with a specific technology, often called a performance standard.

A Standards-based baseline could also apply to retrofit projects if a law or regulation affects CO<sub>2</sub> emissions production at the capture site, such as a mandate to meet a minimum GHG emission performance standard.

New Build CCS Projects: The baseline for new facilities will often correspond with the common practice in the region and the most economic option available to the Project Proponent. As with retrofit projects, provided that there are no regulations in place that require the use of certain technologies, mandate the installation of CCS, or prevent the implementation of the most common technology option, the baseline for a new build facility would likely be the operation of the project configuration without the CCS capture component that vents all of the produced CO<sub>2</sub> to the atmosphere – a Projection-based baseline.

However, multiple economic and market, social, environmental, and political considerations exist that impact technology choices and configurations. Thus, Project Proponents could decide that an emissions performance standard best represents its project circumstances and adopt a Standards-based baseline.

Current regulations shall be considered in determining whether to use a Projection-based or Standards-based baseline for new and existing sources. For example, for new sources, if a GHG regulation requires new sources to meet an emissions performance benchmark, the Standards-based baseline is appropriate and baseline emissions rate shall be set to the this benchmark. For existing sources, a Projection-based baseline is appropriate unless there is some regulation that makes it unlikely that existing source can continue operating as in the past, and is likely to be replaced by a new source having to meet the benchmark.

## 3.2 Additionality Assessment

Emission reductions from the project must be additional, or deemed not to occur in the business-as-usual scenario. The assessment of additionality shall be made based on evaluating the project using the performance standard approach as described below. Project Proponents utilizing this methodology shall consult the latest version of the *ACR Standard*, which may be updated from time to time.

To qualify as additional, the project must

- Pass a regulatory additionality test; and
- Exceed a performance standard

### 3.2.1 Surplus to Regulations (Regulatory Surplus Test)

In order to pass the regulatory surplus test, a project must not be mandated by existing laws, regulations, statutes, legal rulings, or other regulatory frameworks in effect now, or as of the project Start Date, that directly or indirectly affect the credited GHG emissions associated with a project.

The Project Proponent must demonstrate that there is no existing regulation that mandates the project or effectively requires the GHG emission reductions associated with the capture and/or sequestration of

CO<sub>2</sub>. 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.

As noted in Section 3.1.1, if the quantity of CO<sub>2</sub> captured and stored exceeds the requirements imposed by regulation, then those excess reductions are considered surplus and thereby qualify under the methodology (assuming other requirements are met). For example, if CCS enables a new or modified facility to exceed a regulatory performance standard requirement of 1,000 lbs/MWh, then the reductions down to 1,000 lbs/MWh would not be creditable (since mandated by regulation) but those reductions in excess of the requirement are considered surplus and are creditable.

Projects that are deemed to be regulatory surplus are considered surplus for the duration of their Crediting Period. If regulations change during the Crediting Period, this may make the project non-additional and thus ineligible for renewal, but does not affect its additionality during the current Crediting Period.

EOR sites must remain in compliance with State and Federal regulations that are in place at the time of project registration and remain in compliance with those regulations through the injection period. The injection site shall continue to remain in compliance with those regulations during the post injection period until the end of the Project Term.<sup>10</sup>

### 3.2.2 Exceeds a Performance Standard

Projects are required to achieve a level of performance that, with respect to emission reductions or removals, or 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. 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.
- *Emissions rate or benchmark* (e.g., tonnes of CO<sub>2</sub>e emission per unit of output): with examination of sufficient data to assign an emission rate that characterizes the industry, sector or subsector, the net GHG emissions/removals associated with the project activity, in excess of this benchmark, may be considered additional and credited.

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<sup>10</sup> While Project Proponents may choose to not renew the project's Crediting Period under new regulations, to maintain qualification of offset credits that have already been credited, the EOR site must continue to comply with regulations that were in effect at project registration through the Project Term.

Qualifying CCS projects are those that include the capture, transport, and storage of anthropogenic CO<sub>2</sub> in oil and gas reservoirs. Table 3-1 shows the number of operating power, gas processing, ethanol, hydrogen, ammonia, and ethylene oxide production plants that emit an estimated 6.7 million metric tonnes per day of CO<sub>2</sub> into the atmosphere. There is one power plant with commercial-scale CCS that is currently in full operation, and only a small fraction of the gas processing, ethanol, ammonia, and ethylene oxide plants have CCS technologies. The volumes of anthropogenic CO<sub>2</sub> sourced from gas plants and used for EOR are greater than from other sources because of the proximity of gas plants to oil and gas fields. Yet there are only 8 out of a total of 516 gas plants that are currently supplying CO<sub>2</sub> for use in EOR, which is indicative of low penetration rates in this industrial sector. In total only 16 of more than 3,700 industrial facilities currently have CCS. For some sources (e.g. power plants) that emit low concentrations of CO<sub>2</sub>, there is significant research being undertaken to develop various types of capture technologies.

**Table 3-1** Industrial Plants in the US with CCS<sup>11,12,13,14,15,16,17,18,19</sup>

<b>Anthropogenic CO<sub>2</sub> Emission Source</b>	<b>No. of Plants</b>	<b>Estimated CO<sub>2</sub> Emissions (1,000 Metric tonnes per day)</b>	<b>No. of Plants with CCS</b>
Fossil fuel-fired Power Plants	2,802	6,254	1
Gas Processing Plants	516	230	8
Ethanol Plants	210	100	2
Hydrogen Plants (non-refinery)	74	25	1
Hydrogen Plants (refinery)	70	55	0
Ammonia Plants	27	28	3
Ethylene Oxide Plants	10	7	1
<b>TOTAL</b>	<b>3,709</b>	<b>6,699</b>	<b>16</b>

Data on current injection rates of CO<sub>2</sub> during EOR operations in the US were reviewed to quantify adoption rates of anthropogenic CO<sub>2</sub> sequestration in the US.

Figure 3-2 shows the existing CO<sub>2</sub> pipeline system in the US that has evolved over the last thirty-five years. The network connects natural and anthropogenic sources of CO<sub>2</sub> to the following oil producing regions:

<sup>11</sup> The Emissions & Generation Resource Integrated Database for 2014, (EGRID2014), U.S. Environmental Protection Agency, February 2014

<sup>12</sup> Global CCS Institute Project Database, March 2015

<sup>13</sup> Natural Gas Processing Plants in the United States: 2012 Update, US Energy Information Administration, October 2012

<sup>14</sup> US Energy Information Administration at [http://www.eia.gov/electricity/annual/html/epa\\_09\\_01.html](http://www.eia.gov/electricity/annual/html/epa_09_01.html)

<sup>15</sup> Biorefinery locations at <http://ethanolrfa.org/bio-refinery-locations/>, January 8, 2015

<sup>16</sup> Hydrogen Plants: Oil & Gas Journal, Worldwide Refining Survey, December 18, 2006

<sup>17</sup> Ammonia Plants: ICIS Chemical Business, Chemical Profile, Ammonia, October 27-November 28, 2008

<sup>18</sup> <http://ammoniaindustry.com/ammonia-plants-in-north-america/>

<sup>19</sup> Ethylene Oxide: ICIS Chemical Business, Chemical Profile: Ethylene Oxide, June 11-17, 2007

- Permian Basin in Texas and New Mexico
- Gulf Coast Basin including Mississippi, Alabama, Louisiana and Texas
- Rocky Mountain area of Wyoming and Colorado comprising the Powder River, Wind River, Great Divide, Washakie and Piceance Basins
- Williston Basin in Montana and North Dakota, and
- Midcontinent area of Kansas, Oklahoma and the Texas Panhandle

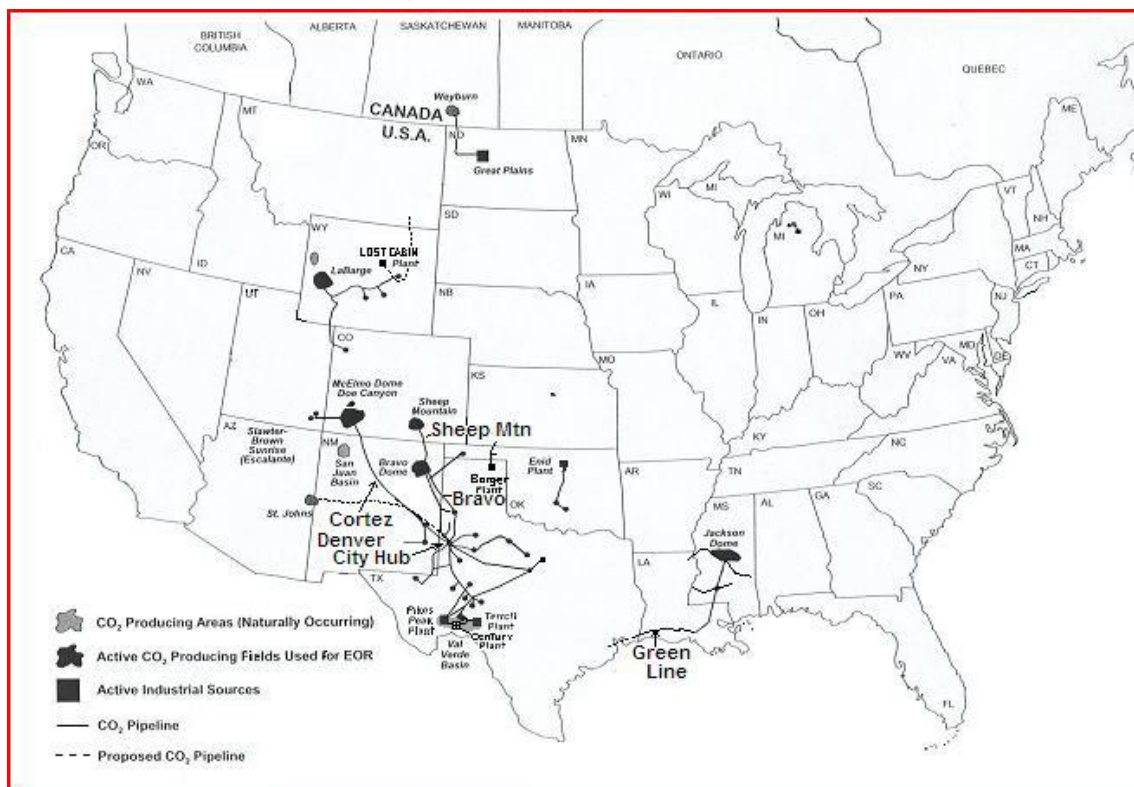


Figure 3-1 Major US CO<sub>2</sub> Pipelines <sup>20</sup>

Table 3-2 provides a listing of these major sources of CO<sub>2</sub>. Total CO<sub>2</sub> usage rates from both natural and anthropogenic sources are 6 billion cubic feet per day (bcfd). It includes approximately 72 percent or 2.6 bcfd obtained from natural sources with the remaining 28 percent or 1.03 bcfd being captured from anthropogenic sources.

The current anthropogenic CO<sub>2</sub> usage rate of 1.03 bcfd (54,000 metric tonnes per day) is significantly small (~0.8 percent) when compared to the estimated total of 6.7 million metric tonnes per day of anthropogenic CO<sub>2</sub> that is emitted to the atmosphere from the industrial sources listed in Table 3-1. It indicates that the penetration levels for the practice of using anthropogenic CO<sub>2</sub> for EOR are extremely low.

<sup>20</sup> A Policy, Legal, and Regulatory Evaluation of the Feasibility of a National Pipeline Infrastructure for the Transport and Storage of Carbon Dioxide, Topical Report, IOGCC, September 10, 2010

The data in Tables 3-1 and 3-2 indicates that the adoption rates of CCS capture technologies for industrial sources as a whole and for individual source types are extremely low, and the injection of anthropogenic CO<sub>2</sub> in hydrocarbon reservoirs during EOR is not common practice.

**Table 3-2** US Natural and Anthropogenic Sources of CO<sub>2</sub> for EOR<sup>21</sup>

Sources	Usage Rates	
	Million standard cubic feet per day (MMscfd)	1,000 metric tonnes per day*
<b>Natural Sources (Domes)</b>		
Mc Elmo Dome	1,200	62
Bravo & West Bravo Dome	290	15
Sheep Mountain & La Veta	50	3
Jackson Dome	950	49
Doe Canyon	110	6
<b>Subtotal</b>	<b>2,600</b>	<b>135</b>
<b>Anthropogenic Sources</b>		
Power Plants (1)	244	13
Natural Gas Plants (8)	457	24
Coal Gasification	150	8
Ammonia Plants (3)	100	5
Ethylene Plant (1)	5	0.3
Ethanol Plants (2)	23	1.2
Hydrogen Plant (1)	53	2.8
<b>Subtotal</b>	<b>1,032</b>	<b>54</b>
<b>Total CO<sub>2</sub> Sources for EOR</b>	<b>3,632</b>	<b>189</b>

\*Conversion factor:19,300 scf/metric tonne

Currently, there are no commercial scale DAC facilities. This technology is in various stages of bench-scale and pilot-scale development and testing.

Based on these low penetration rates, it can be concluded that CCS projects meet a practice-based performance standard and can be considered additional as long as they are not required by regulation.

The penetration rates on which this practice-based performance standard is based will be reassessed periodically after significant changes to the market, or, at a minimum, every 10 years. ACR reserves the right to review the performance standard as necessary to ensure additionality of future projects. All GHG Project Plans for new projects, and all applications for Crediting Period renewal on existing

<sup>21</sup> Follow the CO<sub>2</sub>, How Sources of CO<sub>2</sub> Define Deployment Scenarios for Enhanced Oil Recovery, US DOE, NETL,, presented at the Permian CCS Forum, April 4, 2012

projects, shall apply the regulatory surplus and practice-based performance standard tests in the latest approved revision of this methodology in effect at the time of GHG Project Plan submission or application for Crediting Period renewal.

## 4.0 QUANTIFICATION METHODOLOGY

This section details the methods and equations to quantify baseline emissions, project emissions, and emission reductions. These procedures and equations have been adapted from the accounting framework developed by the Center for Climate and Energy Solutions.<sup>22</sup> Project Proponents shall determine which equations apply to their project based on an evaluation of project and baseline configurations and on project-specific conditions. Figure 2-1 and Table 5-2 can be used as an aid in this determination. Supplemental quantification methods are included in Appendix B.

### 4.1 Baseline Emissions

Two approaches can be used to calculate baseline CO<sub>2</sub> emissions – Projection-based and Standards-based. To be conservative, the procedures do not calculate methane (CH<sub>4</sub>) or nitrous oxide (N<sub>2</sub>O) emissions.

#### 4.1.1 Functional Equivalence

The principle of functional equivalence dictates that the project and baseline shall provide the same function while delivering comparable products in quality and quantity. In the case of CCS projects, the implementation of CO<sub>2</sub> capture infrastructure may result in changes to energy consumption and/or product output, and impact the quantity of GHG emissions produced at the capture site. Since the calculation of baseline emissions involves collecting and using actual project data from the capture site, a Project Proponent could inaccurately quantify emissions reductions from the CCS project if it does not appropriately maintain functional equivalence between the baseline and project, and adjust applied data as necessary.

For example, in some project configurations, incremental emissions associated with operating the capture system could yield an overall increase in CO<sub>2</sub> production and result in a larger volume of CO<sub>2</sub> captured and processed, relative to what the primary process would have emitted in the baseline. A power plant retrofitted with post-combustion CO<sub>2</sub> 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<sub>2</sub> production. In this case, using actual measured CO<sub>2</sub> production values from the project to derive baseline emissions could overestimate baseline emissions.

Alternatively, a similar power plant could burn an equivalent amount of coal as the pre-retrofit plant and correspondingly produce the same amount of CO<sub>2</sub> as the baseline. This might occur if steam from the coal-fired boiler is directed toward the capture system to regenerate the CO<sub>2</sub> absorber rather than the power cycle. Therefore, while the capture system would not cause an increase in total CO<sub>2</sub> production, 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.

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<sup>22</sup> A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects, Center for Climate and Energy Solutions, February, 2012



In other project configurations, some or all of the incremental energy needed to meet the demands of the CO<sub>2</sub> capture system could be provided through separately powered systems, including process heaters, boilers, engines, turbines or other fossil fuel-fired equipment. In this case, the corresponding CO<sub>2</sub> emissions streams would likely be separate from the captured CO<sub>2</sub> from the primary process.

Project Proponents shall adjust actual project data relied upon to quantify baseline emissions, if necessary. This is done to ensure that the quantified emissions reductions appropriately represent the impact 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 being credited for capture and storage of excess CO<sub>2</sub> emissions, i.e., additional CO<sub>2</sub> emissions that could result from poor or negligent operation of the primary process, or from not meeting existing regulations mandating the use of certain technologies, or regulations directly controlling CO<sub>2</sub> emissions or directly controlling other pollutant emissions which indirectly affect CO<sub>2</sub> emissions. The Project Proponent shall provide evidence that the primary process facility was built and is being operated in accordance with its permit requirements and that there were no violations of process conditions or exceedances in emissions of CO<sub>2</sub> and other pollutants. If a violation occurred then the effect on CO<sub>2</sub> emissions shall be evaluated and any increases in CO<sub>2</sub> over normal operations for that time period will be deducted from baseline emissions.

#### **4.1.2 Calculation Procedure for Projection-Based Baseline**

The Projection-based baseline uses actual GHG emissions from the project to represent what would have occurred in the absence of CCS. The procedure involves multiplying the amount of actual CO<sub>2</sub> produced by the primary process, measured immediately downstream of the primary process, by an adjustment factor that accounts for incremental changes in CO<sub>2</sub> produced by the capture equipment and included in the measured CO<sub>2</sub> stream. As discussed above, the adjustment factor is a part of the equation to maintain functional equivalence between the baseline and project. Project Proponents would determine the appropriate way to correct measured CO<sub>2</sub> 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.

For DAC facilities, baseline emissions are determined from the volume of gas and its CO<sub>2</sub> concentration measured at a suitable location in the capture process.

As provided in Equation 4.1, for combustion processes the mass of CO<sub>2</sub> could be determined from flue gas volume and composition measurements.

### Equation 4.1: Total Annual Projection-based Baseline GHG Emissions

$BE_{\text{Projection-Based, } y} = (\text{Vol.}_{\text{Gas Produced, } y} - \text{Vol.}_{\text{excess CO}_2}) \times \%CO_2 \times pCO_2 \times AF$		
Where,		
<b>BE</b> <sub>Projection-Based, y</sub>	=	Baseline emissions for a CCS project where the baseline scenario is defined using a Projection-based approach in each year (tCO <sub>2</sub> /yr).
<b>Vol.</b> <sub>Gas Produced, y</sub>	=	Volume of actual CO <sub>2</sub> gas produced from the primary process, metered at a point immediately downstream of the primary process, or for DAC facilities the volume of the captured gas measured at a suitable location in the process; volume measured at standard conditions, in each year (m <sup>3</sup> gas/yr).
<b>Vol.</b> <sub>excess CO<sub>2</sub>, y</sub>	=	Volume of excess CO <sub>2</sub> gas produced from the primary process due to permit violations (if any) as discussed in Section 4.1; estimated at standard conditions in each year (m <sup>3</sup> gas/yr).
<b>%CO<sub>2</sub></b>	=	% CO <sub>2</sub> in the gas stream, monitored immediately downstream of the primary process, or for DAC facilities monitored immediately downstream of the captured gas volume measurement location, in each year (% volume).
<b>pCO<sub>2</sub></b>	=	Density of CO <sub>2</sub> at standard conditions = 0.00190 metric ton/m <sup>3</sup> .
<b>AF</b>	=	Baseline adjustment factor to account for incremental CO <sub>2</sub> from the capture equipment and included in the measured CO <sub>2</sub> stream (unitless). <sup>23</sup> Determined on a project-by-project basis. If the CO <sub>2</sub> capture system is separately run and operated and the corresponding CO <sub>2</sub> emissions are not included in the Vol. <sub>Gas Produced, y</sub> CO <sub>2</sub> term, then insert 1 (one) for this term. This term is also equal to 1 (one) for DAC facilities. Note: GHG emissions from the capture system are still attributable to the project activity and have to be quantified and included in project emissions as discussed in 4.2.1.

#### 4.1.3 Calculation Procedure for Standards-based Baseline

The Standards-based baseline is calculated by multiplying an emissions intensity metric or rate-based performance standard, expressed as tCO<sub>2</sub>e/unit of output, by the actual output of the project's primary process (e.g., MWh for power generation, MMscf processed for natural gas production, etc.), as provided in Equation 4.2.

<sup>23</sup> This variable is included to maintain functional equivalence between the baseline and project.

An applicable performance standard may be set by regulation based on the type of facility generating the captured CO<sub>2</sub> emissions. Procedures for collecting data from the actual project to determine the 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<sub>2</sub> 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<sub>2</sub> capture. In this case, the Project Proponent shall use gross electricity production as the output instead of net electricity production.

#### Equation 4.2: Total Annual Standards-based Baseline Emissions

$BE_{\text{Standards-based}} = BE_{\text{performance standard}} \times \text{Output}_y$		
Where,		
$BE_{\text{Standards-based}}$	=	Standards-based baseline emissions for a CCS project in year y (tCO <sub>2</sub> /yr).
$BE_{\text{performance standard}}$	=	Baseline emissions intensity metric, specific to the type of primary process that creates the CO <sub>2</sub> for capture, as prescribed by the regulation (tCO <sub>2e</sub> /unit of output).
$\text{Output}_y$	=	Units of output from the CO <sub>2</sub> capture facility (e.g., MWh, MMscf, etc.) in the project condition in year y (units of output).

## 4.2 Project Emissions

CCS project emissions equal the sum of CO<sub>2e</sub> emissions from CO<sub>2</sub> capture, transport, and storage, as shown in Equation 4.3.

#### Equation 4.3: Total Project Emissions

$PE_y = PE_{\text{Capture}, y} + PE_{\text{Transport}, y} + PE_{\text{Storage-P}, y}$		
Where,		
$PE_y$	=	Project emissions from CCS project in year y (tCO <sub>2e</sub> /yr).
$PE_{\text{Capture}, y}$	=	Project emissions from CO <sub>2</sub> capture and compression in year y (tCO <sub>2e</sub> /yr). Refer to Section 4.2.1.
$PE_{\text{Transport}, y}$	=	Project emissions from CO <sub>2</sub> transport in year y (tCO <sub>2e</sub> /yr). Refer to Sections 4.2.2. and 4.2.3.
$PE_{\text{Storage-P}, y}$	=	Project emissions from CO <sub>2</sub> injection and storage in year y (tCO <sub>2e</sub> /yr). Refer to Sections 4.2.4 and 4.2.5.

### 4.2.1 Calculation Procedures for CO<sub>2</sub> Capture

The calculation procedure for the CO<sub>2</sub> capture process reflects the delineation of the boundary of the capture site, which encompasses the source of CO<sub>2</sub>, as well as auxiliary equipment associated with the CO<sub>2</sub> capture and compression systems. In many cases, the primary process that generates the CO<sub>2</sub> is part of a large industrial complex (e.g., a refinery, bitumen upgrader, chemical plant, gas processing plant, etc.) with many processes unaffected by or independent of the CO<sub>2</sub> capture activities. Only those processes directly impacted by the CO<sub>2</sub> capture process are included in the quantification assessment. The boundary of the capture site extends to the point at which CO<sub>2</sub> is transferred to the pipeline operator.

The following equation outlines the methods for calculating emissions from the capture segment of CCS projects. This equation is applicable to pre-combustion capture, post-combustion capture, oxy-fuel capture and CO<sub>2</sub> capture at industrial sites.

#### Equation 4.4: Total Annual Project Emissions from the Capture Segment

<b>PE<sub>Capture, y</sub> = PE<sub>C-PP, y</sub> + PE<sub>C-Comb, y</sub> + PE<sub>C-Indirect Energy, y</sub></b>		
Where,		
<b>PE<sub>Capture, y</sub></b>	=	Project emissions from CO <sub>2</sub> capture and compression in each year (tCO <sub>2</sub> e/yr).
<b>PE<sub>C-PP, y</sub></b>	=	Project emissions from the primary process (physical CO <sub>2</sub> emissions) that have not been captured by the CO <sub>2</sub> capture process, including project emissions from venting of CO <sub>2</sub> during capture and compression, and project emissions from fugitive releases of CO <sub>2</sub> during capture and compression in each year (tCO <sub>2</sub> /yr). Refer to Equation 4.5.
<b>PE<sub>Comb, y</sub></b>	=	Project emissions from on-site use of fossil fuels to operate support equipment for the CO <sub>2</sub> capture and compression facilities in each year (tCO <sub>2</sub> e/yr). Refer to Equation 4.6.
<b>PE<sub>Indirect Energy, y</sub></b>	=	Project emissions from purchased electricity and thermal energy used to operate the CO <sub>2</sub> capture and compression systems in each year (tCO <sub>2</sub> e/yr). Refer to Equation 4.7.

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 the primary process that enter the atmosphere. For example, a post-combustion system might capture 90 percent of CO<sub>2</sub> created by a power production facility; thus, the ten percent not captured is incorporated into the quantification approach to provide a comprehensive representation of the emissions profile of the capture segment of the CCS project.

The calculation approach collectively refers to CO<sub>2</sub> from the primary process emitted to the atmosphere through vent stacks and fugitive releases from equipment at the capture and compression systems as non-captured CO<sub>2</sub>.

Vented and fugitive emissions from capturing and compressing CO<sub>2</sub> include both intentional and unintentional releases. CO<sub>2</sub> may be vented through dedicated vent stacks during normal operation, process upsets, or shutdowns. Fugitive emissions may arise from leakage of CO<sub>2</sub> from equipment such as flanges, valves and flow meters.

The following equations account for the portion of CO<sub>2</sub> generated from the primary process that is not captured but emitted to the atmosphere. Project Proponents calculate emissions by subtracting CO<sub>2</sub> transferred to the transport segment of the CCS project from total CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O produced from the primary process. Table 5-3 provides the monitoring parameters to calculate total annual CO<sub>2</sub> produced from the primary process and transferred to the CO<sub>2</sub> pipeline; it also provides the monitoring parameters necessary for calculating the CH<sub>4</sub> and N<sub>2</sub>O emissions from the primary process.

#### Equation 4.5 Non-Captured CO<sub>2</sub>e Emissions from the Primary Process at the Capture Site

$PE_{C-PP, y} = CO_2 \text{ Produced}_{PP, y} + CO_2e \text{ Produced}_{PP, y} - CO_2 \text{ Transferred}_{PP, y}$		
Where,		
$PE_{C-PP, y}$	=	Project emissions from the primary process that have not been captured by the CO <sub>2</sub> capture process, including project emissions from venting of CO <sub>2</sub> during capture and compression, and project emissions from fugitive releases of CO <sub>2</sub> during capture and compression in each year (tCO <sub>2</sub> /yr).
$CO_2 \text{ Produced}_{PP, y}$	=	Total CO <sub>2</sub> produced from the primary process in each year (tCO <sub>2</sub> /yr), where the volume of gas is measured directly downstream of the primary process. Refer to Equation 4.5a. <sup>24</sup>
$CO_2e \text{ Produced}_{PP, y}$	=	Total CH <sub>4</sub> and N <sub>2</sub> O produced from the primary process in each year (tCO <sub>2</sub> /yr). Only applicable to CO <sub>2</sub> capture projects that use combustion to produce CO <sub>2</sub> for capture. Refer to Equation 4.5b.
$CO_2 \text{ Transferred}_{PP, y}$	=	CO <sub>2</sub> captured and transferred to the CO <sub>2</sub> pipeline, metered at the point of transfer with the pipeline in each year (tCO <sub>2</sub> /yr). Refer Equation 4.5c.

<sup>24</sup> For gasification projects, the total mass of CO<sub>2</sub> produced would be determined based on the mass or volume and carbon content of the syngas produced from the gasifier, measured at a point upstream of the water-gas shift reactor and subsequent hydrogen purification steps. Note that carbon contained in char, slag or ash produced during gasification would not be included in the total amount of produced CO<sub>2</sub>.

**Equation 4.5a: Primary Process CO<sub>2</sub> Emissions<sup>25</sup>**

<b>CO<sub>2</sub> Produced<sub>pp, y</sub> = (Vol.<sub>Gas Produced, y</sub> x %CO<sub>2</sub> x pCO<sub>2</sub>)</b>		
Where,		
<b>CO<sub>2</sub> Produced<sub>pp, y</sub></b>	=	Total CO <sub>2</sub> produced from the primary process in each year (tCO <sub>2</sub> /yr).
<b>Vol.<sub>Gas Produced, y</sub></b>	=	Total volume of CO <sub>2</sub> gas produced from the primary process, metered continuously at a point immediately downstream of the primary process, measured at standard conditions, in each year (m <sup>3</sup> gas/yr).
<b>%CO<sub>2</sub></b>	=	% CO <sub>2</sub> in the gas stream, measured immediately downstream of the primary process, at standard conditions, each year (% volume).
<b>pCO<sub>2</sub></b>	=	Density of CO <sub>2</sub> at standard conditions = 0.00190 metric ton/m <sup>3</sup> .

**Equation 4.5b: Primary Process CH<sub>4</sub> and N<sub>2</sub>O Emissions<sup>26 27</sup>**

<b>CO<sub>2</sub>e Produced<sub>pp, y</sub> = Σ(Fuel<sub>i</sub> x EF CH<sub>4</sub> Fuel i) x CH<sub>4</sub>-GWP + Σ(Fuel<sub>i</sub> x EF N<sub>2</sub>O Fuel i) x N<sub>2</sub>O-GWP</b>		
Where,		
<b>CO<sub>2</sub>e Produced<sub>pp, y</sub></b>	=	Gross amount of CH <sub>4</sub> and N <sub>2</sub> O produced from the primary process in each year (tCO <sub>2</sub> /yr).
<b>Fuel<sub>i</sub></b>	=	Total volume or mass of fuel, by fuel type i, input into the primary process in year each (e.g., m <sup>3</sup> or kg).
<b>EF CH<sub>4</sub> Fuel i</b>	=	CH <sub>4</sub> emission factor for combustion of fossil fuel i (e.g., tCH <sub>4</sub> /m <sup>3</sup> or tCH <sub>4</sub> /kg of fuel).
<b>EF N<sub>2</sub>O Fuel i</b>	=	N <sub>2</sub> O emission factor for combustion of fossil fuel i (e.g., tN <sub>2</sub> O/m <sup>3</sup> or tN <sub>2</sub> O/kg of fuel).
<b>CH<sub>4</sub>-GWP</b>	=	Global Warming Potential of CH <sub>4</sub> . <sup>28</sup>
<b>N<sub>2</sub>O-GWP</b>	=	Global Warming Potential of N <sub>2</sub> O.

<sup>25</sup> See Appendix B for a fuel-based method to calculate emissions from stationary combustion projects which occur during the primary process where direct measurement of CO<sub>2</sub> is not possible.

<sup>26</sup> Applicable to CO<sub>2</sub> capture projects which combust fossil fuels in the primary process.

<sup>27</sup> CH<sub>4</sub> and N<sub>2</sub>O emissions from combustion of fossil fuels are calculated from stationary source combustion emission factors, available at [www.epa.gov/climateleaders/guidance/ghg-emissions.html](http://www.epa.gov/climateleaders/guidance/ghg-emissions.html)

<sup>28</sup> Refer to the ACR Standard for respective GWPs.

#### Equation 4.5c: CO<sub>2</sub> Captured and Input into CO<sub>2</sub> Transport Pipeline

<b>CO<sub>2</sub> Transferred<sub>y</sub> = Vol. Gas Transferred<sub>y</sub> x %CO<sub>2</sub> x pCO<sub>2</sub></b>		
Where,		
<b>CO<sub>2</sub> Transferred<sub>y</sub></b>	=	CO <sub>2</sub> captured and transferred to the CO <sub>2</sub> pipeline, metered at the point of transfer with the pipeline in each year (tCO <sub>2</sub> /yr).
<b>Vol. Gas Transferred<sub>y</sub></b>	=	Total volume of gas that has been captured and input into the pipeline, metered at the point of transfer with the pipeline in each year (m <sup>3</sup> CO <sub>2</sub> /yr).
<b>%CO<sub>2</sub></b>	=	% CO <sub>2</sub> in the gas stream measured at the input to the pipeline, at standard conditions (% volume).
<b>pCO<sub>2</sub></b>	=	Density of CO <sub>2</sub> at standard conditions = 0.00190 metric ton/ m <sup>3</sup> .

Emissions quantification at the CO<sub>2</sub> capture site also includes stationary combustion and electric-drive units to support the capture and compression processes, such as cogeneration units, boilers, heaters, engines, and turbines. For example, the operation of a coal gasifier (primary process) 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 fossil fuel steam generation unit to supply heat to regenerate the CO<sub>2</sub>-rich absorbent, and grid 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<sub>2</sub> capture process (which would not occur in the baseline scenario).

Ultimately, GHG emissions from energy use will depend on the configuration of the capture and compression facilities, the types and quantities of fossil fuels combusted, and electricity, steam and heat consumed to provide energy for the capture and compression processes.

The following equation is used to quantify direct emissions from stationary fossil fuel-driven equipment used for CO<sub>2</sub> capture and compression.

#### Equation 4.6: Capture Site Emissions of CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O from Stationary Combustion Associated with Auxiliary Equipment <sup>29</sup>

$$PE_{C-Comb, y} = \sum (Fuel_i \times EF_{CO_2, Fuel_i}) + \sum (Fuel_i \times EF_{CH_4, Fuel_i}) \times CH_4-GWP \\ + \sum (Fuel_i \times EF_{N_2O, Fuel_i}) \times N_2O-GWP$$

Where,

<b>PE<sub>C-Comb, y</sub></b>	=	Project emissions from combustion of fossil fuels in stationary equipment used to operate the CO <sub>2</sub> capture and compression facilities in each year (tCO <sub>2</sub> e/yr).
<b>Fuel<sub>i</sub></b>	=	Volume or mass of each type of fuel, by fuel type i, used to operate the CO <sub>2</sub> capture and compression facilities in each year (e.g., m <sup>3</sup> /yr or kg/yr).
<b>EF<sub>CO<sub>2</sub>, Fuel i</sub></b>	=	CO <sub>2</sub> emission factor for combustion of fossil fuel i (e.g., tCO <sub>2</sub> /m <sup>3</sup> or tCO <sub>2</sub> /kg of fuel).
<b>EF<sub>CH<sub>4</sub>, Fuel i</sub></b>	=	CH <sub>4</sub> emission factor for combustion of fossil fuel i (e.g., tCH <sub>4</sub> /m <sup>3</sup> or tCH <sub>4</sub> /kg of fuel).
<b>EF<sub>N<sub>2</sub>O, Fuel i</sub></b>	=	N <sub>2</sub> O emission factor for combustion of fossil fuel i (e.g., tN <sub>2</sub> O/m <sup>3</sup> or tN <sub>2</sub> O/ metric ton of fuel).
<b>CH<sub>4</sub>-GWP</b>	=	Global Warming Potential of CH <sub>4</sub> .
<b>N<sub>2</sub>O-GWP</b>	=	Global Warming Potential of N <sub>2</sub> O.

For some CCS project configurations, operating the CO<sub>2</sub> capture and compression processes includes electricity or thermal energy purchased from third parties (e.g., electric utilities or off-site co-generation facilities). Specifically, electricity may be used to operate the compressors, dehydration units, refrigeration units, circulation pumps, fans, air separation units and a variety of other equipment. Purchased steam may be used for various purposes, including regeneration of the CO<sub>2</sub>-rich absorbent used for a post-combustion capture configuration. Electricity may be sourced from direct-connected generating facilities or from the regional electricity grid, while thermal energy may be sourced from nearby steam generators or cogeneration facilities. Thermal energy and electricity may be sourced from separate facilities or sourced from the same combined heat and power generation (cogeneration) facility.

Indirect emissions associated with purchased energy inputs used to operate the CO<sub>2</sub> capture and compression processes may need to be quantified according to equations 4.7, 4.7a, 4.7b, and 4.7c. Table

<sup>29</sup> Emission factors for CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from combustion of fossil fuels are available at [www.epa.gov/climateleaders/guidance/ghg-emissions.html](http://www.epa.gov/climateleaders/guidance/ghg-emissions.html)



5-3 provides the monitoring parameters to calculate CO<sub>2</sub> emissions from purchased and consumed electricity, steam and heat.

### **Emission Factor for Electricity Generation (EF<sub>Electricity</sub>)**

In Equation 4.7a, the emission factor for electricity generation is determined using data from the USEPA's Emissions & Generation Resource Integrated Database (eGRID). eGRID is a comprehensive source of data on the environmental characteristics of electric power generated in the United States, including emissions of nitrogen oxides, sulfur dioxide, carbon dioxide, methane, and nitrous oxide, net generation, resource mix, and other attributes.<sup>30</sup> As of adoption of this methodology, the latest release is the Ninth Edition, version 1.0, containing data through 2010. The latest published version of eGRID shall always be used.

eGRID's Ninth Edition provides data organized by power control area (PCA), North American Electric Reliability Corporation (NERC) region, eGRID subregion, U.S. state, and other levels of aggregation. The PCA, eGRID subregion, and NERC region data are based on electricity generation, transmission and distribution areas, so effectively represent the emissions associated with the mix of GHG-emitting and non-emitting resources used to serve electricity loads in those areas.

The Project Proponent shall use emission factors from the latest version of eGRID available. The Proponent shall download, from the eGRID website, the data files spreadsheet. For eGRID Ninth Edition Version 1.0, this is called "eGRID\_9<sup>th</sup> edition\_V1-0\_year\_2010\_Data.xls". Note the "Contents" tab shows the various levels of aggregation included in the other spreadsheet tabs.

The emission factor is selected in the order of preference below; i.e. if the PCA can be identified the emission factor from this tab must be used. Only if it is not possible to use the preferred level of aggregation is it permitted to move to the next level.

1. In eGRID Ninth Edition version 1.0, the PCAL10 tab has data for 119 Power Control Areas across the United States. This methodology considers those PCA emission factors to be the most precise representation of emissions and thus requires the PCA emission rate to be used as long as the PCA can be identified. In the PCAL10 tab, look up the appropriate PCA in the left-hand column and scroll across to the column entitled "PCA annual CO<sub>2</sub> equivalent total output emission rate (lb/MWh)". Divide this value by 2,205 to convert it to units of tCO<sub>2</sub>e/MWh.
2. If the PCA is not known, use the eGRID subregion data in the SRL10 tab. This includes emission factors for 26 eGRID subregions covering the United States. Look up the appropriate eGRID subregion in the left-hand column and scroll across to the column entitled "eGRID subregion annual CO<sub>2</sub> equivalent total output emission rate (lb/MWh)". Divide this value by 2,205 to convert it to units of tCO<sub>2</sub>e/MWh.
3. If the PCA is not known and it is not feasible to place the project site definitively in an eGRID subregion (e.g. because it is located near a boundary between two subregions), use the data

<sup>30</sup> See <http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html>.

aggregated by U.S. state in the ST10 tab. This will be the least precise because electricity generation, transmission and distribution regions do not follow state boundaries. Look up the state where the project site is located in the left-hand column and scroll across to the column entitled “State annual CO<sub>2</sub> equivalent total output emission rate (lb/MWh)”. Divide this value by 2,205 to convert it to units of tCO<sub>2</sub>e/MWh.

#### Equation 4.7: CO<sub>2</sub> Emissions from Purchased and Consumed Electricity, Steam, and Heat

<b>PE<sub>C-Indirect Energy, y</sub> = PE<sub>Elec, y</sub> + PE<sub>Cogen, y</sub></b>		
Where,		
<b>PE<sub>C-Indirect Energy, y</sub></b>	=	Project emissions from purchased electricity and thermal energy used to operate the CO <sub>2</sub> capture and compression facilities in each year (tCO <sub>2</sub> e/yr).
<b>PE<sub>Elec, y</sub></b>	=	Project emissions from grid electricity used to operate the CO <sub>2</sub> capture and compression facilities in each year (tCO <sub>2</sub> e/yr). Refer to Equation 4.7a.
<b>PE<sub>Cogen, y</sub></b>	=	Project emissions from thermal energy and/or electricity purchased from third party operated heat and/or power generation facilities used to operate the CO <sub>2</sub> capture and compression facilities in each year (tCO <sub>2</sub> e/yr). Refer to Equation 4.7b.

#### Equation 4.7a: CO<sub>2</sub> Emissions from Purchased and Consumed Electricity

<b>PE<sub>Elec, y</sub> = Electricity x EF<sub>Electricity</sub></b>		
Where,		
<b>PE<sub>Elec, y</sub></b>	=	Project emissions from grid electricity used to operate the CO <sub>2</sub> capture and compression facilities in each year (tCO <sub>2</sub> e/yr).
<b>Electricity</b>	=	Total metered grid electricity usage from equipment used to operate the CO <sub>2</sub> capture and compression facilities in each year (MWh).
<b>EF<sub>Electricity</sub></b>	=	Emission factor for electricity generation in the relevant region, by (in order of preference) PCA, eGRID subregion, or State (tCO <sub>2</sub> e/MWh).

**Equation 4.7b: CO<sub>2</sub>, CH<sub>4</sub>, N<sub>2</sub>O Emissions from Purchased and Consumed Steam and /or Heat<sup>31</sup>**

$$PE_{\text{cogen, y}} = \sum(\text{Fuel}_i \times EF_{\text{CO}_2 \text{ Fuel } i}) + \sum(\text{Fuel}_i \times EF_{\text{CH}_4 \text{ Fuel } i}) \times \text{CH}_4\text{-GWP} \\ + \sum(\text{Fuel}_i \times EF_{\text{N}_2\text{O} \text{ Fuel } i}) \times \text{N}_2\text{O-GWP}$$

Where,

<b>PE<sub>cogen, y</sub></b>	=	Project emissions from thermal energy and/or electricity purchased from third party operated heat and/or power generation facilities used to operate the CO <sub>2</sub> capture and compression facilities in each year (tCO <sub>2</sub> e/yr).
<b>Fuel<sub>i</sub></b>	=	Proportionate volume or mass of each type of fuel, by fuel type i, combusted by the third party cogeneration unit to supply electricity or thermal energy to the CO <sub>2</sub> capture and compression facilities in each year (e.g., m <sup>3</sup> /yr or kg/yr). Refer to Equation 4.7c.
<b>EF CO<sub>2</sub> Fuel i</b>	=	CO <sub>2</sub> emission factor for combustion of fossil fuel i (e.g., tCO <sub>2</sub> /m <sup>3</sup> or tCO <sub>2</sub> /kg of fuel).
<b>EF CH<sub>4</sub> Fuel i</b>	=	CH <sub>4</sub> emission factor for combustion of fossil fuel i (e.g., tCH <sub>4</sub> /m <sup>3</sup> or tCH <sub>4</sub> /kg of fuel).
<b>EF N<sub>2</sub>O Fuel i</b>	=	N <sub>2</sub> O emission factor for combustion of fossil fuel i (e.g., tN <sub>2</sub> O/m <sup>3</sup> or tN <sub>2</sub> O/kg of fuel).
<b>CH<sub>4</sub>-GWP</b>	=	Global Warming Potential of CH <sub>4</sub> .
<b>N<sub>2</sub>O-GWP</b>	=	Global Warming Potential of N <sub>2</sub> O.

<sup>31</sup> Emission factors for CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from combustion of fossil fuels are available at [www.epa.gov/climateleaders/guidance/ghg-emissions.html](http://www.epa.gov/climateleaders/guidance/ghg-emissions.html)

#### Equation 4.7c: Apportionment of Cogeneration Emissions by Product

$\text{Fuel}_i = \text{Total Fuel}_{\text{Cogen}} \times [(\text{Heat}_{\text{CCS Project}} + \text{Electricity}_{\text{CCS Project}}) / (\text{Heat}_{\text{Cogen}} + \text{Electricity}_{\text{Cogen}})]$		
Where,		
<b>Fuel<sub>i</sub></b>	=	Proportionate volume or mass of each type of fuel, by fuel type i, combusted by the third party cogeneration unit to supply electricity or thermal energy to the CO <sub>2</sub> capture and compression facilities in each year (e.g., m <sup>3</sup> /yr or metric tons/yr). <sup>32</sup>
<b>Total Fuel<sub>Cogen</sub></b>	=	Total volume or mass of each type of fuel, by fuel type i, combusted by the third party cogeneration unit supplying electricity or thermal energy to the CO <sub>2</sub> capture and compression facilities in each year (e.g., m <sup>3</sup> /yr or metric tons/yr).
<b>Heat<sub>CCS Project</sub></b>	=	Quantity of thermal energy purchased from the third party cogeneration unit to operate the CO <sub>2</sub> capture facilities (MWh/year).
<b>Electricity<sub>CCS Project</sub></b>	=	Quantity of electricity purchased from the third party cogeneration unit to operate the CO <sub>2</sub> capture and compression facilities (MWh/year).
<b>Heat<sub>Cogen</sub></b>	=	Total quantity of thermal energy generated by the third party cogeneration unit (MWh/year).
<b>Electricity<sub>Cogen</sub></b>	=	Total quantity of electricity generated by the third party cogeneration unit (MWh/year).

#### 4.2.2 Calculation Procedures for CO<sub>2</sub> Transport

The GHG emission quantification approach for the transport segment of a CCS project includes the full pipeline system from the CO<sub>2</sub> delivery point at the capture site (downstream of the compressor) to the CO<sub>2</sub> delivery point at the storage site. The calculation methodology also applies to CO<sub>2</sub> transported in containers (e.g., by barge, rail or truck).

For pipeline transport, the emissions quantification procedures in this section apply to a CCS project that includes a dedicated pipeline moving CO<sub>2</sub> from the capture site to the storage site. For CO<sub>2</sub> transport using a network of pipelines, where project CO<sub>2</sub> can be commingled with CO<sub>2</sub> from other sources (e.g. in West Texas), different quantification procedures using system-wide emission factors can be used as outlined in Section 4.2.3.

GHG emissions from CO<sub>2</sub> transport by pipeline include CO<sub>2</sub> emissions from venting and fugitive releases as well as CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O emissions from stationary combustion and electricity use. For transport of

<sup>32</sup> The CO<sub>2</sub> capture unit may only require a portion of the total electricity and/or heat output from the cogeneration unit so it might be necessary to account for the fraction of emissions from the cogeneration unit that are attributable to the CCS project

CO<sub>2</sub> in containers, mobile sources (barge, rail, or truck) are the main source of GHG emissions. There may be venting and fugitive emissions depending on the nature of equipment used to transport the CO<sub>2</sub> containers. These emissions shall also be calculated and accounted for under project emissions from the transport segment. Table 5-3 provides monitoring parameters to calculate emissions from CO<sub>2</sub> transport.

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

#### Equation 4.8: Total Project Emissions from the Transport Segment

<b>PE<sub>Transport, y</sub> = PE<sub>T-Comb, y</sub> + PE<sub>T-VF, y</sub> + PE<sub>T-Electricity, y</sub> + PE<sub>T-Mobile, y</sub></b>		
Where,		
<b>PE<sub>Transport, y</sub></b>	=	Project emissions from CO <sub>2</sub> transport in year y (tCO <sub>2e</sub> /yr).
<b>PE<sub>T-Comb, y</sub></b>	=	Project emissions from combustion of fossil fuels in stationary equipment used to maintain and operate the CO <sub>2</sub> pipeline facilities in each year (tCO <sub>2e</sub> /yr). Refer to Equation 4.9. This term does not apply to CO <sub>2</sub> transport by barge, rail, or truck.
<b>PE<sub>T-VF, y</sub></b>	=	Project emissions from venting events and fugitive releases from the CO <sub>2</sub> pipeline or from the CO <sub>2</sub> containers during transport and associated equipment in each year (tCO <sub>2e</sub> /yr). Refer to Equation 4.10.
<b>PE<sub>T-Electricity, y</sub></b>	=	Project emissions from electricity consumed to operate the CO <sub>2</sub> pipeline and associated equipment in each year (tCO <sub>2e</sub> /yr). Refer to Equation 4.11. This term does not apply to CO <sub>2</sub> transport by barge, rail, or truck.
<b>PE<sub>T-Mobile, y</sub></b>	=	Project emissions from each mode of transport (barge, rail, or truck) used to transport the CO <sub>2</sub> containers from capture site to the storage site in each year (tCO <sub>2e</sub> /yr). Refer to Equation 4.12. This term does not apply to CO <sub>2</sub> transport by pipeline.

A variety of stationary combustion equipment is used to maintain and operate the CO<sub>2</sub> pipeline. Stationary combustion equipment that is a part of CO<sub>2</sub> pipeline could include engines, turbines, heaters, etc. For some projects, additional 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<sub>2</sub> transport are quantified according to the following equation.

**Equation 4.9: CO<sub>2</sub>, CH<sub>4</sub>, N<sub>2</sub>O Emissions from Stationary Combustion for CO<sub>2</sub> Transport<sup>33</sup>**

$$PE_{T-Comb, y} = \sum (Fuel_i \times EF_{CO_2, Fuel_i}) + \sum (Fuel_i \times EF_{CH_4, Fuel_i}) \times CH_4-GWP + \sum (Fuel_i \times EF_{N_2O, Fuel_i}) \times N_2O-GWP$$

Where,

<b>PE<sub>T-Comb, y</sub></b>	=	Project emissions from combustion of fossil fuels in stationary equipment to maintain and operate the CO <sub>2</sub> pipeline infrastructure in each year (tCO <sub>2</sub> e/yr).
<b>Fuel<sub>i</sub></b>	=	Volume or mass of each type of fuel, by fuel type i, used in each year (e.g., m <sup>3</sup> /yr or kg/yr).
<b>EF<sub>CO<sub>2</sub>, Fuel i</sub></b>	=	CO <sub>2</sub> emission factor for combustion of fossil fuel i (e.g., tCO <sub>2</sub> /m <sup>3</sup> or tCO <sub>2</sub> /kg of fuel).
<b>EF<sub>CH<sub>4</sub>, Fuel i</sub></b>	=	CH <sub>4</sub> emission factor for combustion of fossil fuel i (e.g., tCH <sub>4</sub> /m <sup>3</sup> or tCH <sub>4</sub> /kg of fuel).
<b>EF<sub>N<sub>2</sub>O, Fuel i</sub></b>	=	N <sub>2</sub> O emission factor for combustion of fossil fuel i (e.g., tN <sub>2</sub> O/m <sup>3</sup> or tN <sub>2</sub> O/ metric ton of fuel).
<b>CH<sub>4</sub>-GWP</b>	=	Global Warming Potential of CH <sub>4</sub> .
<b>N<sub>2</sub>O-GWP</b>	=	Global Warming Potential of N <sub>2</sub> O.

This methodology presents a mass balance approach to calculate transport-related vented and fugitive CO<sub>2</sub> emissions. Venting and fugitive emissions of CO<sub>2</sub> are grouped together in the mass balance determination.

The following equation is used to quantify venting and fugitive emissions from the CO<sub>2</sub> pipeline according to the mass balance method.

<sup>33</sup> Emission factors for CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from combustion of fossil fuels are available at [www.epa.gov/climateleaders/guidance/ghg-emissions.html](http://www.epa.gov/climateleaders/guidance/ghg-emissions.html)

**Equation 4.10: Vented and Fugitive CO<sub>2</sub> Emissions from CO<sub>2</sub> Transport**

<b>PE<sub>T-VF, y</sub> = CO<sub>2</sub> Received<sub>Capture, y</sub> - CO<sub>2</sub> Supplied<sub>Storage, y</sub></b>		
Where,		
<b>PE<sub>T-VF, y</sub></b>	=	Project emissions from venting events and fugitive releases from the CO <sub>2</sub> pipeline and associated equipment in each year (tCO <sub>2</sub> e/yr).
<b>CO<sub>2</sub> Received<sub>Capture, y</sub></b>	=	CO <sub>2</sub> captured and input into the pipeline, metered at the point of transfer with the capture site in each year (tCO <sub>2</sub> /yr). Refer to Equation 4.10a.
<b>CO<sub>2</sub> Supplied<sub>Storage, y</sub></b>	=	CO <sub>2</sub> supplied to the storage site operator, metered at the point of transfer with the storage site in each year (tCO <sub>2</sub> /yr). Refer to Equation 4.10b.

**Equation 4.10a: CO<sub>2</sub> Captured and Input into CO<sub>2</sub> Pipeline**

<b>CO<sub>2</sub> Received<sub>Capture, y</sub> = Vol. Gas Received<sub>y</sub> x %CO<sub>2</sub> x pCO<sub>2</sub></b>		
Where,		
<b>CO<sub>2</sub> Received<sub>Capture, y</sub></b>	=	CO <sub>2</sub> captured and input into the pipeline or container, metered at the point of transfer with the capture site in each year (tCO <sub>2</sub> /yr).
<b>Vol. Gas Received<sub>y</sub></b>	=	CO <sub>2</sub> captured and input into the pipeline or container, metered at the point of transfer with the capture site in each year at standard conditions (m <sup>3</sup> CO <sub>2</sub> /yr).
<b>%CO<sub>2</sub></b>	=	% CO <sub>2</sub> in the gas stream measured at the point of transfer with the capture site (% volume).
<b>pCO<sub>2</sub></b>	=	Density of CO <sub>2</sub> at standard conditions = 0.00190 metric ton/m <sup>3</sup> .

**Equation 4.10b: CO<sub>2</sub> Transferred from CO<sub>2</sub> Pipeline to CO<sub>2</sub> Storage Site**

<b>CO<sub>2</sub> Supplied<sub>Storage, y</sub> = Vol. Gas Supplied, y x %CO<sub>2</sub> x pCO<sub>2</sub></b>		
Where,		
<b>CO<sub>2</sub> Supplied<sub>Storage, y</sub></b>	=	CO <sub>2</sub> supplied to the storage site operator, metered at the point of transfer with the storage site in each year (tCO <sub>2</sub> /yr).
<b>Vol. Gas Supplied, y</b>	=	Volume of gas that has been supplied to the storage site operator, metered at the point of transfer with the storage site in each year at standard conditions (m <sup>3</sup> CO <sub>2</sub> /yr).
<b>%CO<sub>2</sub></b>	=	% CO <sub>2</sub> in the gas stream measured at the transfer with the storage site (% volume). <sup>34</sup>
<b>pCO<sub>2</sub></b>	=	Density of CO <sub>2</sub> at standard conditions = 0.00190 metric ton/ m <sup>3</sup> .

A mass balance method is not appropriate in situations where the uncertainty of the measured values is greater than the magnitude of the quantified emissions.<sup>35</sup> In those cases, vented and fugitive emissions shall be estimated using a component count method. To use the component count method an inventory of equipment (fittings, valves, etc.) is compiled in order to apply fugitive emission factors to estimate emissions from the pipeline. Venting events must also be logged to estimate venting emissions (e.g., intentional pipeline releases). The component-count method to calculate vented and fugitive emissions is presented in the CO<sub>2</sub> storage segment calculation procedures.

In some CCS project configurations, grid electricity may be purchased to operate the CO<sub>2</sub> transport infrastructure. In particular, electric-drive compressors may be used for supplemental compression along the CO<sub>2</sub> pipeline, where grid connectivity permits. The indirect emissions associated with purchased electricity for CO<sub>2</sub> transport can be quantified according to the following equation.

<sup>34</sup> Composition of gas delivered to storage site is assumed to be same composition as the gas at inlet to the pipeline or received by container.

<sup>35</sup> This can be done by performing an uncertainty analysis for Eq. 4.10 and comparing the result with the difference between **CO<sub>2</sub> Received<sub>Capture, y</sub>** and **- CO<sub>2</sub> Supplied<sub>Storage, y</sub>**.



**Equation 4.11: CO<sub>2</sub>e Emissions from Electricity Consumption for CO<sub>2</sub> Transport**

<b>PE<sub>T-Elec, y</sub> = Electricity x EF<sub>Electricity</sub></b>		
Where,		
<b>PE<sub>T-Elec, y</sub></b>	=	Project emissions from electricity usage from equipment used to operate the CO <sub>2</sub> pipeline transport infrastructure in each year (tCO <sub>2</sub> e/yr).
<b>Electricity</b>	=	Total metered electricity usage from equipment used to operate the CO <sub>2</sub> pipeline transport infrastructure in each year (MWh).
<b>EF<sub>Electricity</sub></b>	=	Emission factor for electricity generation in the relevant region, by (in order of preference) PCA, eGRID subregion, or State (tCO <sub>2</sub> e/MWh). See Section 4.2.1 for estimation procedures.

Mobile source emissions for CO<sub>2</sub> transport by barge, rail, or truck modes are calculated by aggregating the ton-miles transported by each mode and multiplying the individual totals by an appropriate mode-specific emission factor. Total CO<sub>2</sub>e emissions are calculated from the following equation:

**Equation 4.12: CO<sub>2</sub>e Emissions from Mobile Transport of CO<sub>2</sub> Containers<sup>36</sup>**

<b>PE<sub>T-Mobile, y</sub></b>	=	<b><math>\sum(\text{Ton-miles}_i \times \text{EF}_{\text{CO}_2, i} \times 10^{-3}) + \sum(\text{Ton-miles}_i \times \text{EF}_{\text{CH}_4, i} \times 10^{-6}) \times \text{CH}_4\text{-GWP} + \sum(\text{Ton-miles}_i \times \text{EF}_{\text{N}_2\text{O}, i} \times 10^{-6}) \times \text{N}_2\text{O-GWP}</math></b>
Where,		
<b>PE<sub>T-Mobile, y</sub></b>	=	Total emissions from all modes of transport (barge, rail, or truck) that were used to transport the CO <sub>2</sub> containers from capture site to the storage site in each year (tCO <sub>2</sub> e/yr).
<b>Ton-miles<sub>i</sub></b>	=	Ton-miles for each mode of transport, by mode type i, used to transport the CO <sub>2</sub> containers in each year. Note: the ton-miles calculation includes the weight of the container plus the weight of the contained CO <sub>2</sub> (ton-miles/yr).
<b>EF<sub>CO<sub>2</sub>, i</sub></b>	=	CO <sub>2</sub> emission factor for mode i (barge, rail, or truck), (kg/ton-mile).
<b>EF<sub>CH<sub>4</sub>, i</sub></b>	=	CH <sub>4</sub> emission factor for mode i (barge, rail, or truck), (g/ton-mile).
<b>EF<sub>N<sub>2</sub>O, i</sub></b>	=	N <sub>2</sub> O emission factor for mode i (barge, rail, or truck), (g/ton-mile).
<b>CH<sub>4</sub>-GWP</b>	=	Global Warming Potential of CH <sub>4</sub> .
<b>N<sub>2</sub>O-GWP</b>	=	Global Warming Potential of N <sub>2</sub> O.

<sup>36</sup> Emission factors for CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions for product transport are available at [www.epa.gov/climateleaders/guidance/ghg-emissions.html](http://www.epa.gov/climateleaders/guidance/ghg-emissions.html)

### 4.2.3 Calculating CO<sub>2</sub> Transport Emissions According to System-Wide Emission Factors

The emissions quantification procedure for the CO<sub>2</sub> pipeline transport segment corresponds with a CCS project that includes a dedicated pipeline moving CO<sub>2</sub> from the capture site to the storage site. However, CCS projects could use pipeline systems that carry streams of CO<sub>2</sub> from multiple capture sites to one or more geologic storage reservoirs. Thus, an emissions accounting approach that pro-rates CO<sub>2</sub> losses according to a proportional use of a pipeline's annual throughput or a share of a storage site's annual CO<sub>2</sub> injection is appropriate. The project proponent shall work with the entity responsible for the CO<sub>2</sub> pipeline to obtain a reasonable system-wide emission factor (percent losses of the total) and calculate its CO<sub>2</sub> losses (emissions). For example, if a pipeline operator has sufficient records of CO<sub>2</sub> imported and exported out of its system, it could determine a fugitive CO<sub>2</sub> factor according to a mass-balance approach. Pipeline operators could also derive a system-wide fugitive CO<sub>2</sub> emissions factor from a comprehensive component count assessment.<sup>37</sup> For completeness, a comprehensive loss factor shall also incorporate vented and stationary combustion emission sources within the appropriate GHG assessment boundary, and emissions from purchased electricity.

### 4.2.4 Calculation Procedures for CO<sub>2</sub> Storage

The emissions calculation procedures for CO<sub>2</sub> storage cover direct CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from stationary combustion; CO<sub>2</sub> and CH<sub>4</sub> emissions from venting and fugitive releases to the atmosphere; and indirect CO<sub>2</sub>e emissions from purchased electricity use. The procedures also account for any CO<sub>2</sub> that is produced with the hydrocarbons and transferred offsite (i.e., the CO<sub>2</sub> is not re-injected into a reservoir that is within the project boundary) and leakage of injected CO<sub>2</sub> from the reservoir to the atmosphere. GHG sources include CO<sub>2</sub> receiving, injecting, recycling and re-injection equipment; CO<sub>2</sub> injection and production wells, hydrocarbon processing and storage facilities; and the CO<sub>2</sub> storage reservoir.

The emissions quantification methodology for CO<sub>2</sub> storage includes all emissions sources located between the point of transfer from the CO<sub>2</sub> pipeline up to and including the injection wells. It also incorporates producing wells and surface facilities related to the hydrocarbon gathering, storage and separation facilities and the infrastructure used to process, purify and compress CO<sub>2</sub> and other gases produced from the formation, and re-inject it back into the formation. Additionally, CO<sub>2</sub> entrained in or dissolved in hydrocarbons (crude oil or natural gas) or waste water that is removed or distributed off-site (e.g., sold, disposed of and/or not re-injected) is accounted for as a source of fugitive emissions.

Emissions from energy inputs to operate the facilities at EOR formations are accounted for by using common quantification methods based on the quantities and types of energy inputs. Vented CO<sub>2</sub> emissions from surface facilities are quantified on an event basis. Fugitive CO<sub>2</sub> emissions from injection

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<sup>37</sup> Project developers could derive a CO<sub>2</sub> pipeline emission factors based on natural gas transmission factors and then convert from methane to CO<sub>2</sub> (emissions CO<sub>2</sub>/kilometer of pipeline). The American Petroleum Institute's Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry (2004) is one source for a pipeline emissions factor.

wells and surface facilities are calculated according to a component count approach. The method to calculate leaked CO<sub>2</sub> from the geologic storage reservoir to the atmosphere, should it occur, would be reservoir-specific and is addressed in Section 4.2.5.

The methodology does not treat CO<sub>2</sub> produced from wells at EOR sites that is recycled and re-injected into the storage formation as an emission, provided the CO<sub>2</sub> remains within the closed loop system and is thus prevented from entering the atmosphere. Unintentional CO<sub>2</sub> releases from the recycle system (including from production wells, gas separation and cleaning equipment) are treated as fugitive emissions and accounted for in Equation 4.16. Intentionally vented CO<sub>2</sub> in the recycle system (for operational purposes) is treated as a vented emission and accounted for in Equation 4.15.

The following equation outlines the methods for calculating emissions from CO<sub>2</sub> storage. Table 5-3 provides monitoring parameters for calculating emissions from CO<sub>2</sub> storage.

**Equation 4.13: Total Project Emissions from CO<sub>2</sub> Storage**

$$PE_{Storage-P, y} = PE_{S-P-Comb, y} + PE_{S-P-Vent, y} + PE_{S-P-Fug, y} + PE_{S-P-Elec, y} + PE_{S-P-CO_2 Transfer} + PE_{S-P-Leakage, y}$$

Where,

<b>PE<sub>Storage-P, y</sub></b>	=	Project emissions from CO <sub>2</sub> injection and storage in each year (tCO <sub>2</sub> e/yr).
<b>PE<sub>S-P-Comb, y</sub></b>	=	Project emissions from combustion of fossil fuels in stationary equipment at the storage site – e.g., to maintain and operate the CO <sub>2</sub> handling and injection wells, CO <sub>2</sub> recycling devices, and associated hydrocarbon production facilities in each year (tCO <sub>2</sub> e/yr). Refer to Equation 4.14.
<b>PE<sub>S-P-Vent, y</sub></b>	=	Project emissions from venting of CO <sub>2</sub> at the injection wells or other surface facilities located between the point of transfer from the CO <sub>2</sub> pipeline and the injection wells in the formation; at the producing wells; at the hydrocarbon gathering processing and storage facilities; or at the CO <sub>2</sub> processing and recycling facilities in each year (tCO <sub>2</sub> e/yr). Refer to Equation 4.15.
<b>PE<sub>S-P-Fug, y</sub></b>	=	Project emissions from fugitive releases of CO <sub>2</sub> or CH <sub>4</sub> at the injection wells or other surface facilities located between the point of transfer from the CO <sub>2</sub> pipeline and the injection wells; at the producing wells; at the hydrocarbon gathering processing and storage facilities; at the CO <sub>2</sub> processing and recycling facilities; and from CO <sub>2</sub> entrained in hydrocarbons or water produced from the formation and distributed offsite in each year (tCO <sub>2</sub> e/yr). Refer to Equation 4.16.
<b>PE<sub>S-P-Elec, y</sub></b>	=	Project emissions from consumption of electricity used to operate equipment at the producing formation at the storage site in each year (tCO <sub>2</sub> e/yr). Refer to Equation 4.17.
<b>PE<sub>S-P-CO<sub>2</sub> Transfer</sub></b>	=	Produced CO <sub>2</sub> from an enhanced oil or gas recovery operation transferred offsite in each year (tCO <sub>2</sub> /yr). Refer to Equation 4.18.
<b>PE<sub>S-P-Leakage, y</sub></b>	=	Project emissions from leakage of injected CO <sub>2</sub> from the geologic storage reservoir in the producing formation to the atmosphere in each year (tCO <sub>2</sub> e/yr). For information on accounting for CO <sub>2</sub> leakage emissions from geologic storage formations to the atmosphere see Section 4.2.5.

Various types of stationary combustion equipment may be used to maintain and operate the CO<sub>2</sub> injection, storage, processing and recycling facilities and to operate the EOR facilities (e.g., batteries, gathering systems, oil-water-gas separators). The following equation is used to quantify GHG emissions from all stationary fossil fuel-driven equipment used to operate the CO<sub>2</sub> injection and storage facilities.

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**Equation 4.14: CO<sub>2</sub>, CH<sub>4</sub>, N<sub>2</sub>O Emissions from Stationary Combustion and Flaring for CO<sub>2</sub> Storage<sup>39</sup>**

$$PE_{S-P-Comb, y} = \sum (Fuel_i \times EF_{CO_2, Fuel_i}) + \sum (Fuel_i \times EF_{CH_4, Fuel_i}) \times CH_4-GWP + \sum (Fuel_i \times EF_{N_2O, Fuel_i}) \times N_2O-GWP + PE_{Flaring, y}$$

Where,

<b>PE<sub>S-P-Comb, y</sub></b>	=	Project emissions from combustion of fossil fuels in stationary equipment at the storage site – e.g., to maintain and operate the CO <sub>2</sub> handling and injection wells, CO <sub>2</sub> recycling devices, and EOR-associated hydrocarbon production facilities in each year (tCO <sub>2</sub> e/yr).
<b>Fuel<sub>i</sub></b>	=	Volume or mass of each type of fuel, by fuel type i, used to inspect, maintain and operate the CO <sub>2</sub> storage infrastructure and hydrocarbon production facilities in each year (e.g., m <sup>3</sup> /yr or kg/yr).
<b>EF<sub>CO<sub>2</sub>, Fuel i</sub></b>	=	CO <sub>2</sub> emission factor for combustion of fossil fuel i (e.g., tCO <sub>2</sub> /m <sup>3</sup> or tCO <sub>2</sub> /kg of fuel).
<b>EF<sub>CH<sub>4</sub>, Fuel i</sub></b>	=	CH <sub>4</sub> emission factor for combustion of fossil fuel i (e.g., tCH <sub>4</sub> /m <sup>3</sup> or tCH <sub>4</sub> /kg of fuel).
<b>EF<sub>N<sub>2</sub>O, Fuel i</sub></b>	=	N <sub>2</sub> O emission factor for combustion of fossil fuel i (e.g., tN <sub>2</sub> O/m <sup>3</sup> or tN <sub>2</sub> O/kg of fuel).
<b>CH<sub>4</sub>-GWP</b>	=	Global Warming Potential of CH <sub>4</sub> .
<b>N<sub>2</sub>O-GWP</b>	=	Global Warming Potential of N <sub>2</sub> O.
<b>PE<sub>Flaring, y</sub></b>	=	Project emissions from flaring of gases at hydrocarbon production facilities in year y (tCO <sub>2</sub> e/yr). Only applicable to facilities that flare gases that may contain CO <sub>2</sub> originating from the producing formation. See Equation B-6 (Appendix B).

<sup>38</sup> Appendix B provides a procedure for calculating emissions from combusting hydrocarbons produced at the formation (e.g., in flares).

<sup>39</sup> Emission factors for CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from combustion of fossil fuels are available at [www.epa.gov/climateleaders/guidance/ghg-emissions.html](http://www.epa.gov/climateleaders/guidance/ghg-emissions.html)

Venting may occur at the injection wells or at other surface facilities, located between the CO<sub>2</sub> transfer meter at the pipeline and the injection wells. It could also happen at the production wells, the hydrocarbon production and storage facilities, or at the facilities used to process and recycle the produced CO<sub>2</sub> 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.

The following equation can be used to calculate vented emissions from the injection wells and other surface facilities at the CO<sub>2</sub> storage site.

**Equation 4.15: Vented CO<sub>2</sub>e Emissions from CO<sub>2</sub> Storage**

$$PE_{S-P-Vent, y} = \sum_{j=1}^2 \sum_{i=1}^I N_{\text{Blowdown } i} \times V_{\text{Blowdown } i} \times \%GHG_j \times \rho_{GHGj} \times GWP_j \times 0.001$$

Where,

<b>PE<sub>S-P-Vent, y</sub></b>	=	Project emissions from vented CO <sub>2</sub> at the injection wells or other surface facilities located between the point of transfer from the CO <sub>2</sub> pipeline and the injection wells in the producing formation; at the producing wells; at the hydrocarbon gathering processing and storage facilities; or at the CO <sub>2</sub> processing and recycling facilities in each year (tCO <sub>2</sub> e/yr).
<b>N<sub>Blowdown i</sub></b>	=	Number of blowdowns for equipment i in each year, obtained from blowdown event logs retained by storage site operator.
<b>V<sub>Blowdown i</sub></b>	=	Total volume of blowdown equipment chambers for equipment i (including pipelines, manifolds and vessels between isolation valves) (m <sup>3</sup> , ft <sup>3</sup> ). For well releases use measured or estimated gas volumes released using procedures in USEPA subpart W <sup>40</sup> .
<b>%GHG<sub>j</sub></b>	=	Concentration of GHG 'j' in the injected gas in year y (volume percent GHG, expressed as a decimal fraction). j=1 for CO <sub>2</sub> and j=2 for CH <sub>4</sub> .
<b>ρ<sub>GHG j</sub></b>	=	Density of relevant GHG (CO <sub>2</sub> or CH <sub>4</sub> ) at conditions in the blowdown chamber, kg/m <sup>3</sup> or kg/ft <sup>3</sup> . At standard conditions ρ <sub>CO2</sub> = 0.0538 kg/ft <sup>3</sup> and ρ <sub>CH4</sub> = 0.0196 kg/ft <sup>3</sup> . <sup>41</sup>
<b>GWP<sub>j</sub></b>	=	100 year Global Warming Potential of relevant GHG
<b>0.001</b>	=	Conversion factor to convert from kg to metric tons.

Fugitive emissions of CO<sub>2</sub>, and in some cases CH<sub>4</sub>, may occur at the injection wells or at other surface facilities, located between the CO<sub>2</sub> pipeline transfer meter and the injection wells. Fugitive emissions could also occur at production wells, the hydrocarbon production and storage facilities, and/or at the facilities used to process and recycle the produced CO<sub>2</sub> for re-injection into the formation. Fugitive

<sup>40</sup> US Environmental Protection Agency. Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, Final Rule: Subpart W. November 30, 2010; and subsequent amendments available at <http://www.epa.gov/ghgreporting/reporters/subpart/w-regdocs.html>

<sup>41</sup> For CO<sub>2</sub> Injection pump blowdowns it may be necessary to use the density of CO<sub>2</sub> at supercritical conditions, which can be obtained from the National Institute of Standards and Technology (NIST) Database of thermodynamic properties using the Span and Wagner Equation of State.

emission sources could include fittings, flanges, valves, connectors, meters, and headers (large pipes that mix the oil stream from multiple wellheads). Fugitive emissions may also result from the release of residual CO<sub>2</sub> entrained or dissolved in produced oil, water or gas that is transferred from the hydrocarbon recovery facilities to downstream users.

Fugitive CO<sub>2</sub> and CH<sub>4</sub> emissions from injection wells and other surface equipment are calculated on a component count approach. Fugitive emissions of CO<sub>2</sub> entrained in or dissolved in hydrocarbon liquids or gases or water produced from the formation and distributed off-site are calculated based on quantities of crude oil, water and gas produced and the CO<sub>2</sub> content of each product. Since produced water is often injected back into the producing formation as part of the EOR process, those volumes are not included in this fugitive emissions calculation. Project Proponents shall only include fluids leaving the project boundary.

The following equation is used to calculate fugitive emissions from the injection wells and other surface facilities at the CO<sub>2</sub> storage site.

**Equation 4.16: Fugitive CO<sub>2</sub>e Emissions from Wells and Surface Equipment**

$PE_{S-P-Fugitive, y} = PE_{S-P-Fug-Equipment, y} + PE_{S-P-Fug-Entrained CO_2, y}$		
Where,		
$PE_{S-P-Fugitive, y}$	=	Project emissions from fugitive releases of CO <sub>2</sub> or CH <sub>4</sub> at the injection wells or other surface facilities located between the point of transfer from the CO <sub>2</sub> pipeline and the injection wells; at the producing wells; at the hydrocarbon gathering processing and storage facilities; at the CO <sub>2</sub> processing and recycling facilities; and from CO <sub>2</sub> entrained in hydrocarbons or water produced from the formation and distributed off-site in each year (tCO <sub>2</sub> e/yr).
$PE_{S-P-Fug-Equipment, y}$	=	Fugitive emissions of CO <sub>2</sub> (and CH <sub>4</sub> if relevant) from equipment located at the injection wells or other surface facilities located between the point of transfer from the CO <sub>2</sub> pipeline and the injection wells; at the producing wells; at the hydrocarbon gathering processing and storage facilities; and at the CO <sub>2</sub> processing and recycling facilities in each year (tCO <sub>2</sub> e/yr). Refer to Equation 4.16a.
$PE_{S-P-Fug-Entrained CO_2, y}$	=	Fugitive emissions of CO <sub>2</sub> entrained in or dissolved in hydrocarbon liquids or gases or water produced from the formation and distributed off-site (sold or otherwise disposed of and not re-injected) in each year (tCO <sub>2</sub> /yr). Refer to Equation 4.16b.



Equation 4.16a: CO<sub>2</sub> & CH<sub>4</sub> Fugitive Emissions from Equipment Leaks

$$PE_{S-P-Fug-Equipment, y} = \sum_{j=1}^2 \sum_{s=1}^S Count_s \times EF_s \times T_s \times \%GHG_j \times \rho_{GHGj} \times GWP_j \times 0.001$$

Where,

<b>PE<sub>S-P-Fug-Equipment, y</sub></b>	=	Fugitive of GHG 'i' (CO <sub>2</sub> and CH <sub>4</sub> , if relevant) from equipment located at the injection wells or other surface facilities located between the point of transfer from the CO <sub>2</sub> pipeline and the injection wells; at the producing wells; at the hydrocarbon gathering processing and storage facilities; and at the CO <sub>2</sub> processing and recycling facilities in each year (tCO <sub>2</sub> e/yr).
<b>Count<sub>s</sub></b>	=	Total number of each type of emission source at the injection wellheads and at surface facilities located between the point of transfer from the CO <sub>2</sub> pipeline and the injection wells; at the producing wells; at the hydrocarbon gathering processing and storage facilities; and at the CO <sub>2</sub> processing and recycling facilities.
<b>EF<sub>s</sub></b>	=	Population emission factor for the specific fugitive emission source, 's', in Table W1-A and Tables W-3 through Table W-7 of Subpart W (standard cubic feet per hour per component).
<b>T<sub>s</sub></b>	=	Total time that the equipment associated with the specific fugitive emission source s was operational in year y (hours). Where equipment hours are unknown, assume 8760 hours/year.
<b>%GHG<sub>j</sub></b>	=	Concentration of GHG 'j' (CO <sub>2</sub> or CH <sub>4</sub> ) in the injected or produced gas (Volume fraction CO <sub>2</sub> or CH <sub>4</sub> ). j=1 for CO <sub>2</sub> and j=2 for CH <sub>4</sub> .
<b>ρ<sub>GHGj</sub></b>	=	Density of relevant GHG (CO <sub>2</sub> or CH <sub>4</sub> ) at standard conditions in kg/m <sup>3</sup> or kg/ft <sup>3</sup> . At standard conditions ρ <sub>CO2</sub> = 0.0538 kg/ft <sup>3</sup> and ρ <sub>CH4</sub> = 0.0196 kg/ft <sup>3</sup> .
<b>GWP<sub>j</sub></b>	=	100 year Global Warming Potential of relevant GHG
<b>0.001</b>	=	Conversion factor to convert from kg to metric tons.

**Equation 4.16b: CO<sub>2</sub> Fugitive Emissions Entrained in Produced Hydrocarbons**

$PE_{S-P-Fug-Entrained\ CO_2, y} = (Vol._{Gas\ Sold} \times \% CO_2_{Gas\ Sold} \times \rho_{CO_2} \times 0.001) +$ $(Mass_{Water\ Prod} \times Mass\ Frac_{CO_2\ in\ Water}) +$ $(Mass_{Oil\ Prod} \times Mass\ Frac_{CO_2\ in\ Oil})$	
Where,	
$PE_{S-P-Fug-Entrained\ CO_2, y}$	= Fugitive emissions or other losses of CO <sub>2</sub> entrained or dissolved in crude oil/other hydrocarbons, produced water and natural gas that have been separated from the produced CO <sub>2</sub> for sale or disposal. Calculated based on quantities of crude oil, water and gas produced and the CO <sub>2</sub> content of each product (tCO <sub>2</sub> /yr).
$Vol._{Gas\ Sold}$	= Volume of natural gas or fuel gas, produced from the formation that CO <sub>2</sub> is being injected into, that is sold to third parties or input into a natural gas pipeline in year y (m <sup>3</sup> /yr, measured at standard conditions).
$\% CO_2_{Gas\ Sold}$	= % CO <sub>2</sub> in the natural gas or fuel gas that is sold to third parties or input into a natural gas pipeline, in year y (% volume).
$\rho_{CO_2}$	= Density of CO <sub>2</sub> at standard conditions (= 1.899 kg /m <sup>3</sup> ).
<b>0.001</b>	= Conversion factor to convert from kg to metric tons.
$Mass_{Water\ Prod}$	= Mass of water produced from the formation that CO <sub>2</sub> is being injected into, that is disposed of or otherwise not re-injected back into the formation (metric tons/yr).
$Mass\ Frac_{CO_2\ in\ Water}$	= Mass fraction of CO <sub>2</sub> in the water produced from the formation.
$Mass_{Oil\ Prod}$	= Mass of crude oil and other hydrocarbons produced from the formation that CO <sub>2</sub> is being injected into (metric tons/year).
$Mass\ Frac_{CO_2\ in\ Oil}$	= Mass fraction of CO <sub>2</sub> in the crude oil and other hydrocarbons produced from the formation.

Purchased electricity may be used to operate pumps, compressors and other equipment at the injection wells and producing wells; at oil and gas gathering, storage and processing facilities (e.g., oil-water-gas separators); or at CO<sub>2</sub> processing, compression, recycling and re-injection facilities.

For example, many EOR projects install additional water pumping capacity to alternate water injection and CO<sub>2</sub> injection (water alternating gas (WAG) injection), which may also require electricity. Electric compression could be used to recycle produced CO<sub>2</sub> 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 vapors 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.

Indirect GHG emissions from purchased electricity used to operate equipment at the EOR operations are quantified according to the following equation.

**Equation 4.17: CO<sub>2</sub>e Emissions from Purchased Electricity Consumption for CO<sub>2</sub> Storage**

<b>PE<sub>S-P-Elec, y</sub> = Electricity x EF<sub>Electricity</sub></b>		
Where,		
<b>PE<sub>S-P-Elec, y</sub></b>	=	Project emissions from electricity used to operate equipment at the CO <sub>2</sub> storage site in each year (tCO <sub>2</sub> e/yr).
<b>Electricity</b>	=	Total metered electricity usage from equipment used to operate the storage site and the hydrocarbon production facilities in year y (MWh).
<b>EF<sub>Electricity</sub></b>	=	Emission factor for electricity generation in the relevant region, by (in order of preference) PCA, eGRID subregion, or State (tCO <sub>2</sub> e/MWh). See Section 4.2.1 for estimation procedures

A Project Proponent could move produced-CO<sub>2</sub> between EOR production fields if it includes the multiple fields within the project boundary (making sure to account for emissions from the relevant stationary combustion, vented, and fugitive sources at all the fields, and between fields, in which the captured CO<sub>2</sub> is injected). In some instances, however, CO<sub>2</sub> can be transferred out of the project boundary. While this CO<sub>2</sub> is not necessarily an emission to the atmosphere, Project Proponents shall nevertheless account for it as an emission rather than treating it as if it were sequestered from the atmosphere.

Equation 4.18 presents the approach to calculate emissions from CO<sub>2</sub> transferred outside the project boundary. Note: Project Proponents shall not include any CO<sub>2</sub> volumes that were sold to third parties and already accounted for under Equation 4.16b.

**Equation 4.18: CO<sub>2</sub> Transferred Outside Project Boundaries**

<b><math>PE_{S-P-CO_2\_Transfer} = Vol_{CO_2\_Transfer} \times \rho_{CO_2} \times 0.001</math></b>		
Where,		
<b><math>PE_{S-P-CO_2\_Transfer}</math></b>	=	Produced CO <sub>2</sub> from an EOR operation transferred outside project boundary in each year (tCO <sub>2</sub> /yr).
<b><math>Vol_{CO_2\_Transfer}</math></b>	=	Volume of produced CO <sub>2</sub> from an enhanced oil or gas operation transferred outside project boundary in each year under standard conditions (m <sup>3</sup> , ft <sup>3</sup> ).
<b><math>\rho_{CO_2}</math></b>	=	Density of CO <sub>2</sub> at standard conditions (1.899 kg/m <sup>3</sup> or 0.0538 kg/ft <sup>3</sup> ).
<b>0.001</b>	=	Conversion factor to convert from kg to metric tons.

**4.2.5 Accounting for Atmospheric Leakage of CO<sub>2</sub> from the Storage Volume**

Any injected CO<sub>2</sub> that is not produced with the oil remains contained in the oil reservoir because of the confining layer above the oil reservoir that traps it in place. This is the same confining layer that formed an effective seal and contained the oil and gas in the reservoir for millions of years and now serves to trap the CO<sub>2</sub>. However, Project Proponents must quantify atmospheric leakage of CO<sub>2</sub> emissions from the storage volume, if they arise. Atmospheric leakage shall be monitored during the entire Project Term, which includes the injection period and a time-period following the end of injection as defined in Section 2.2. Methods to assure the long-term storage of CO<sub>2</sub> beyond the Project Term will be required; these and associated reversal risk mitigation measures are outlined in Section 5.4

The following general equation to account for atmospheric leakage from the CO<sub>2</sub> storage volume reproduces a formula from the EPA's Greenhouse Gas Reporting Program. It directs storage site operators to identify leakage pathways from the subsurface and aggregate total annual emissions from each CO<sub>2</sub> emissions pathway, should a leak be detected.

In this methodology, the details of detecting and estimating atmospheric leakage are discussed in Section 5.4. If atmospheric leakage is detected during injection operations, it must be quantified and deducted as project emissions in the year the leakage was detected using equation 4.19. If the estimated atmospheric leakage is large and exceeds the ERs calculated for that year (See Section 4.3 for calculation of ERs), it can be mitigated by options discussed in Section 6.3 (Table 6-1).

**Equation 4.19: Atmospheric Leakage of CO<sub>2</sub> Emissions from CO<sub>2</sub> Storage Volume During the Injection Period<sup>42</sup>**

$$\text{CO}_{2\text{Atm. Leakage-INJ},y} = \sum_{z=1}^Z \text{CO}_{2z,y}$$

Where,

$\text{CO}_{2\text{Atm. Leakage-INJ}}$	=	Total mass of CO <sub>2</sub> emitted to the atmosphere through subsurface leakage from the formation in year y during the injection period (metric tons).
$\text{CO}_{2z}$	=	Total mass of CO <sub>2</sub> emitted through leakage pathway z in year y (metric tons).
z	=	Leakage pathway.

Equation 4.20, which is similar to Eq. 4.19, is used to report atmospheric leakage that occurs after the injection period. Mitigation of post-injection leakage is discussed in Section 6.3.

**Equation 4.20: Atmospheric Leakage of CO<sub>2</sub> Emissions from CO<sub>2</sub> Storage Volume After the Injection Period**

$$\text{CO}_{2\text{Atm. Leakage-PI}} = \sum_{z=1}^Z \text{CO}_{2z}$$

Where,

$\text{CO}_{2\text{Atm. Leakage-PI}}$	=	Total mass of CO <sub>2</sub> emitted to the atmosphere through subsurface leakage from the formation after the injection period (metric tons).
$\text{CO}_{2z}$	=	Total mass of CO <sub>2</sub> emitted through leakage pathway z (metric tons).
z	=	Leakage pathway.

### 4.3 Emission Reductions

As shown in Equation 4.21, overall GHG emission reductions (ERs) from the CCS project equal Baseline Emissions minus Project Emissions.

<sup>42</sup> 40 CFR §98.443(e), Eq. RR-10, 40

**Equation 4.21: Total Annual GHG Reductions**

$$\text{GHG ER}_y = \text{BE}_y - \text{PE}_y$$

Where,

**GHG ER<sub>y</sub>** = Total annual GHG reductions from the CCS project (tCO<sub>2</sub>e/yr).

**BE<sub>y</sub>** = Baseline CO<sub>2</sub>e emissions in each year (from eq. 4.1 or 4.2, tCO<sub>2</sub>e/yr).

**PE<sub>y</sub>** = Project CO<sub>2</sub>e emissions in each year (from eq. 4.3, tCO<sub>2</sub>e/yr).

## 5.0 DATA COLLECTION AND MONITORING

### 5.1 Reporting Period

The reporting period can be defined at the discretion of the Project Proponent, provided it conforms to ACR's guidelines on reporting periods. The *ACR Standard* requires a field visit by the verifier at minimum every 5 years. In between field visits, verification may be via a desktop assessment, which may be annual or at any other interval at the Project Proponent's discretion, but verification is required prior to any issuance of offset credits.

### 5.2 Baseline Emissions Measurement

Baseline emission measurement parameters and considerations are summarized in Table 5-1 for the Projection-based and Standards-based calculation procedures. Details of the calculation procedures are included in Section 4.0.

Table 5-1 Overview of Baseline Emissions Calculation Procedures

Type of Baseline	GHGs	Description	Monitoring Considerations
<b>Projection Based Baseline</b>	CO <sub>2</sub>  To be conservative, CH <sub>4</sub> and N <sub>2</sub> O excluded from the baseline quantification	<b><u>Section 4.1.2 Equation 4.1</u></b> Baseline emissions for a Projection-based baseline are calculated by measuring total CO <sub>2</sub> produced by the primary process in the actual project. In certain cases, the amount of CO <sub>2</sub> used to calculate baseline emissions may need to be adjusted to account for the incremental CO <sub>2</sub> generated to meet the energy requirements of the capture process. This could occur if the energy required to operate the CO <sub>2</sub> capture process equipment is provided by electricity or thermal energy generated from the same process producing the captured CO <sub>2</sub> . Quantify the incremental mass of CO <sub>2</sub> generated at the capture site (to adjust the measured CO <sub>2</sub> value and properly account for the parasitic load from the CO <sub>2</sub> capture equipment) by calculating the CO <sub>2</sub> emissions from using steam to regenerate the CO <sub>2</sub> absorber according to facility engineering design information or from metered steam usage and steam conversion factors appropriate for the facility. Further, any additional CO <sub>2</sub> emissions that could result from poor or negligent operation of the primary process, or from not meeting regulations, which are included in the baseline shall be deducted as excess CO <sub>2</sub> emissions. Determine excess CO <sub>2</sub> emissions from violations to facility permit conditions and deduct from baseline as indicated in Equation 4.1.	Total volume of CO <sub>2</sub> produced by the actual project's primary process.  Steam used to meet the parasitic loads from the CO <sub>2</sub> capture and compression equipment, if necessary.
<b>Standards Based Baseline</b>	CO <sub>2</sub>  To be conservative, CH <sub>4</sub> and N <sub>2</sub> O excluded from the baseline quantification	<b><u>Section 4.1.3 Equation 4.2</u></b> The Standards-based baseline is calculated by multiplying emissions intensity metric or performance standard, expressed as (tCO <sub>2</sub> e/unit of output), by the actual output of the project's primary process (e.g., MWh for power generation, MMscf processed for natural gas production). The emissions intensity metric may be a region-specific or CCS project-type specific standard that is set by Federal, State, or Local Regulatory Agencies. Procedures for collecting data from the actual project to determine the output value used to calculate baseline emissions shall be set to maintain functional equivalence between baseline emissions and project emissions and ensure that the quantified emissions reductions appropriately represents the impact of the CCS project.	Measurement of output based on the type of primary process. Output shall be measured to account for the total output from the primary process that would have occurred in the absence of the project.

### 5.3 Project Emissions Measurements

Project emission sources and GHG measurement parameters are summarized in Table 5-2. Details of the calculation procedures are included in Section 4.0. In addition to measurement parameters shown in Table 5-2, a detailed monitoring, reporting, and verification (MRV) plan must be developed for each geologic storage site used in the CCS project. The MRV plan is discussed in Section 5.4.



**Table 5-2** Overview of Project Emissions Calculation Procedures

Emission Sources Type & GHGs	Description	Key Monitoring Parameters
<b>CO<sub>2</sub> Capture</b>		
Total Capture Emissions CO <sub>2</sub> ; CH <sub>4</sub> ; N <sub>2</sub> O	<b><u>Section 4.2.1, Equation 4.4.</u></b> Total project emissions from CO <sub>2</sub> capture processes, including direct and indirect emissions.	N/A
Non-captured CO <sub>2</sub> from the primary process Vented & Fugitive CO <sub>2</sub>	<b><u>Section 4.2.1, Equations 4.5, 4.5a, 4.5b, 4.5c.</u></b> CO <sub>2</sub> emissions from the primary process, which has not been captured by the CO <sub>2</sub> capture equipment and transferred to the transport (pipeline) segment. Non-captured CO <sub>2</sub> includes CO <sub>2</sub> emitted to the atmosphere from the capture site via vent stacks at the primary process and via venting or fugitive releases from other equipment at the capture and compression facilities. This quantity of CO <sub>2</sub> is equal to the difference between the total quantity of CO <sub>2</sub> produced and the quantity of CO <sub>2</sub> input into the pipeline.	Total volume of gas produced from the primary process, and captured and input into the pipeline
Stationary Combustion CO <sub>2</sub> ; CH <sub>4</sub> ; N <sub>2</sub> O	<b><u>Section 4.2.1, Equation 4.5b, 4.6, 4.7b</u></b> A fuel-based calculation method, which applies to <ol style="list-style-type: none"> <li>1) primary process CH<sub>4</sub> and N<sub>2</sub>O emissions for projects that generate CO<sub>2</sub> for capture through combustion, and</li> <li>2) equipment used to capture and compress CO<sub>2</sub>, including cogeneration units, boilers, heaters, engines, turbines, flares, etc, which are owned and controlled by the capture site located at all capture sites.</li> <li>3) cogeneration units operated by third parties supplying process energy (e.g, steam, electricity) that are used by the project.</li> </ol>	Annual amount of fossil fuel burned, by fuel type

Emission Sources Type & GHGs	Description	Key Monitoring Parameters
Electricity and Thermal Energy Use CO <sub>2</sub> ; CH <sub>4</sub> ; N <sub>2</sub> O	<b><u>Section 4.2.1, Equation 4.7, 4.7a, 4.7b, 4.7c.</u></b> Indirect emissions from purchased and consumed electricity and thermal energy (steam) used to operate the CO <sub>2</sub> capture and compression equipment. Electricity may be used to operate the CO <sub>2</sub> compressors, dehydration units, refrigeration units, circulation pumps, fans, air separation units and a variety of other equipment. Purchased steam may be used for various purposes, including regeneration of the CO <sub>2</sub> -rich absorbent used for a post-combustion capture configuration.	Total quantities of electricity and steam used to operate the CO <sub>2</sub> capture equipment
<b>CO<sub>2</sub> Transport</b>		
Total Transport Emissions CO <sub>2</sub> ; CH <sub>4</sub> ; N <sub>2</sub> O	<b><u>Section 4.2.2, Equation 4.8.</u></b> Total Project Emissions from CO <sub>2</sub> transport, including vented, fugitive, stationary combustion, and purchased and consumed electricity and mobile sources.	N/A
Stationary Combustion CO <sub>2</sub> ; CH <sub>4</sub> ; N <sub>2</sub> O	<b><u>Section 4.2.2, Equation 4.9.</u></b> Emissions from fossil fuel combustion to operate equipment used to transport CO <sub>2</sub> to the storage site. For some projects, additional compression may be required along the pipeline or at an interconnection with a pipeline that is operated at a higher pressure. A variety of stationary combustion equipment may be used to inspect, maintain and operate the CO <sub>2</sub> pipeline. Stationary combustion equipment could include engines, turbines and heaters etc. that are under the direct control of the CO <sub>2</sub> pipeline operator.	Annual amount of fossil fuel burned, by fuel type
Vented & Fugitive CO <sub>2</sub>	<b><u>Section 4.2.2, Equations 4.10, 4.10a, 4.10b.</u></b> Vented and fugitive emissions are calculated according to a mass balance approach using metered values at the point of transfer at the capture site and at the storage site. Venting and fugitive releases during CO <sub>2</sub> transportation. Fugitive emissions may arise from leakage of CO <sub>2</sub> from equipment such as flanges, valves and flow meters. Emissions could also arise from compressor seal vents or pressure release valves. As discussed in Section 4.2.2 in certain situations, emissions shall be calculated according to an event-based approach for vented emissions and a component-count method for fugitive emissions. See “Vented CO <sub>2</sub> ” & “Fugitive CO <sub>2</sub> ” sources under “CO <sub>2</sub> Storage”.	Metered quantities of CO <sub>2</sub> input into the pipeline or container (if transported by barge, rail, or truck) and delivered to storage site

Emission Sources Type & GHGs	Description	Key Monitoring Parameters
Electricity Use (if required) CO <sub>2</sub> ; CH <sub>4</sub> ; N <sub>2</sub> O	<b><u>Section 4.2.2, Equation 4.11.</u></b> Indirect emissions from electricity used to operate the CO <sub>2</sub> transport infrastructure. In some CCS project configurations, electric-drive compressors may be used for supplemental compression along the CO <sub>2</sub> pipeline, where grid connectivity exists.	Metered quantity of electricity used to operate the CO <sub>2</sub> transport equipment
Mobile Sources (for transport by barge, rail, or truck) CO <sub>2</sub> ; CH <sub>4</sub> ; N <sub>2</sub> O	<b><u>Section 4.2.2, Equation 4.12</u></b> Emissions associated with the mode of transport (barge, rail, or truck) used to transport CO <sub>2</sub> containers from the capture to storage site. Multiple modes of transport may be used and the emissions associated with each mode shall be calculated separately and aggregated.	Records of CO <sub>2</sub> container weights and mileage for each trip by each transport mode.
<b>CO<sub>2</sub> Storage</b>		
Total Storage Emissions – CO <sub>2</sub> ; CH <sub>4</sub> ; N <sub>2</sub> O	<b><u>Section 4.2.4, Equation 4.13</u></b> Total Project Emissions from CO <sub>2</sub> storage including stationary combustion, vented, fugitive, and electricity consumption emissions.	N/A
Stationary Combustion CO <sub>2</sub> ; CH <sub>4</sub> ; N <sub>2</sub> O	<b><u>Section 4.2.4, Equation 4.14.</u></b> Emissions from fossil fuel combustion to operate equipment used to store CO <sub>2</sub> in the oil and gas reservoir. Equipment could be used to operate, maintain or inspect the CO <sub>2</sub> injection, storage, processing and recycling facilities and to operate the hydrocarbon production and processing facilities (e.g., gathering systems, oil-water-gas separators). Emissions may occur from combustion of fossil fuels or combustion of hydrocarbons produced from the formation (e.g., in flares).	Annual amount of fossil fuel burned, by fuel type

Emission Sources Type & GHGs	Description	Key Monitoring Parameters
Vented CO <sub>2</sub> ; CH <sub>4</sub>	<p><b><u>Section 4.2.4, Equation 4.15</u></b></p> <p>Emissions from CO<sub>2</sub> venting at the storage site – e.g., the injection wells or other surface facilities located between the point of transfer with the CO<sub>2</sub> pipeline and the injection wells. Venting may also occur at the production wells, the hydrocarbon production and storage facilities or at the facilities used to process and recycle the produced CO<sub>2</sub> for re-injection into the formation. Planned venting may occur during shutdowns and maintenance work, while unplanned venting may occur during process upsets. The amount of CO<sub>2</sub> vented would be determined based on the number of events and the volume of gas contained within the equipment.</p>	Number of venting events; volume of CO <sub>2</sub> per event.
Fugitive CO <sub>2</sub> ; CH <sub>4</sub> (excluding atmosphere leakage from the storage volume)	<p><b><u>Section 4.2.4, Equations 4.16, 4.16a, 4.16b.</u></b></p> <p>Fugitive emissions calculated according to a component count method. Fugitive emissions at the storage site are unintended CO<sub>2</sub> leaks from equipment that occur at the injection wells and other surface facilities, located between the transfer meter at the pipeline and the injection wells, and between the producing wells and hydrocarbon production facilities. Examples of fugitive CO<sub>2</sub> sources for EOR operations include production wells, hydrocarbon production and storage facilities, and equipment used to process and recycle produced CO<sub>2</sub> for re-injection into the formation. Specific locations where CO<sub>2</sub> leaks occur include fittings, flanges, valves, connectors, meters, and headers (which are large pipes that mix the oil stream from multiple wellheads). Fugitive emissions may also result from the release of residual CO<sub>2</sub> entrained or dissolved in produced oil, water or gas that is transferred from the hydrocarbon recovery facilities to downstream users.</p>	Component count of fugitive emission sources; hours of operation for equipment

Emission Sources Type & GHGs	Description	Key Monitoring Parameters
Electricity Use CO <sub>2</sub> ; CH <sub>4</sub> ; N <sub>2</sub> O	<p><b><u>Section 4.2.4, Equation 4.17.</u></b></p> <p>Indirect emissions from electricity use at the CO<sub>2</sub> storage site. Grid electricity may be used to operate pumps (e.g., for incremental water injection as part of a Water Alternating Gas (WAG) injection processes), compressors and other equipment at the injection wells and producing wells; at oil and gas gathering, storage and processing facilities (e.g., oil-water-gas separators); or at CO<sub>2</sub> processing, compression, recycling and re-injection facilities. Electric compression may also be used to recycle produced CO<sub>2</sub> and other gases for re-injection into the formation. Electric-drive equipment may also be used to operate vapor recovery units to recover vapors from oil and water tanks, to operate flash gas compressors to 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.</p>	Metered quantity of electricity used to operate CO <sub>2</sub> storage and recycling equipment
Transferred CO <sub>2</sub> CO <sub>2</sub>	<p><b><u>Section 4.2.4, Equation 4.18.</u></b></p> <p>While not technically an emission, CO<sub>2</sub> transferred outside the project boundary (i.e., produced CO<sub>2</sub> from an EOR operation not re-injected but moved offsite) is deducted from claimed emissions reductions. If an EOR site operator intends to move produced-CO<sub>2</sub> between fields, then the boundary would encompass the multiple fields employed (making sure to account for emissions from all relevant stationary combustion, vented, and fugitive emissions sources).</p>	Volume of produced CO <sub>2</sub> from an EOR operation transferred outside project boundary
Atmospheric leakage of CO <sub>2</sub> from the storage volume CO <sub>2</sub>	<p><b><u>Section 4.2.5, Equations 4.19 and 4.20.</u></b></p> <p>For properly selected, operated, and closed CO<sub>2</sub> storage operations, atmospheric leakage of CO<sub>2</sub> emissions from the geologic reservoir will not normally occur. Should it occur then emissions shall be calculated on a site-by-site basis as described in Section 5.4. For CO<sub>2</sub> storage, the project-specific MRV Plan would include a strategy for detecting and quantifying any surface CO<sub>2</sub> leakage – i.e., leakage to atmosphere estimated based on monitoring and measurements completed as part of the MRV plan.</p>	Total mass of CO <sub>2</sub> emitted through leakage pathways to atmosphere

## 5.4 Monitoring, Reporting, and Verification (MRV) Plan

The IOGCC's Task Force on Carbon Capture and Geologic Storage concluded that monitoring and verification of CCS projects would be accomplished best in the subsurface, given the uncertainties and changing technologies of surface monitoring techniques.<sup>43</sup> The Task Force has recommended that the operator submit a comprehensive monitoring plan that is tailored to the specific characteristics of the site. Similar recommendations were made by the USDOE, which indicated that MRV programs need to be flexible and site-specific to adapt to the inherent variability and heterogeneity of geologic systems. MRV plans also change in scope as a project progresses from the pre-injection phase to the post-injection phase. For all these reasons, MRV plans need to be tailored to site-specific geologic conditions and operational considerations.<sup>44</sup>

### 5.4.1 MRV Plan Framework

A MRV framework for CCS projects shall include the following components:

- Determination of the storage volume that is expected to contain the injected CO<sub>2</sub> during and after the injection period, determined through modeling and flow simulations.
- Identification of potential leakage pathways within this storage volume (usually well bores, faults, and fractures). This information can also feed into the flow simulation model as a potential source of uncertainty.
- Remediation of potential leakage pathways, as needed. This can help reduce the probability of leakage and reduce uncertainty in detecting atmospheric leakage.
- Development of a monitoring strategy to demonstrate effective retention of anthropogenic CO<sub>2</sub> during injection and post-injection periods and for detection of the potential for atmospheric leakage.
- A strategy for quantifying any atmospheric leakage of CO<sub>2</sub>.
- A plan for monitoring the parameters included in Table 5-3.

#### 5.4.1.1 Determination of Storage Volume

The storage volume is the rock volume planned to contain the injected CO<sub>2</sub>, which includes a vertical and lateral boundary. The vertical boundary shall be set at the top of the confining zone. The lateral boundary shall be set initially at the expected lateral extent of the plume. The lateral extent is

<sup>43</sup> Storage of Carbon Dioxide in Geologic Structures, A Legal and Regulatory Guide for States and Provinces, The Interstate Oil and Gas Compact Commission, September 2007

<sup>44</sup> Best Practices for Monitoring, Verification, and Accounting of CO<sub>2</sub> Stored in Deep Geologic Formations – 2012 Update, DOE/NETL-2012/1568, October 2012

determined through flow simulations of the injection conducted to a point in time when the CO<sub>2</sub> plume ceases to migrate after injection is stopped. The simulation shall account for uncertainties in modeled parameters and potential leakage pathways that could lead to leakage. It may be necessary to redefine the lateral boundary during operations, if the actual injection process differs from the modeled scenarios or other changes are detected that affect the extent of the lateral boundary. An additional buffer region shall be included to account for these uncertainties and for conservativeness. Both vertical and lateral boundaries shall encompass the limits of acceptable CO<sub>2</sub> migration.

#### *5.4.1.2 Identification and Remediation of Potential Atmospheric Leakage Pathways*

Potential leakage pathways shall be determined through a detailed site characterization. Examples of conduits for CO<sub>2</sub> leaks to the atmosphere include CO<sub>2</sub> injection wells, oil or gas production wells, monitoring wells, abandoned wells; and faults and fractures. While for properly selected, operated, and closed CO<sub>2</sub> storage operations, CO<sub>2</sub> emissions from the geologic reservoir to the atmosphere should not occur, assessing for potential leakage pathways is an important part of a monitoring program.

Site characterization includes the development of a complete catalogue of existing wells penetrating the injection zone or in the near vicinity of the reservoir, including information on the current well status, data on how the well was completed (and plugged/ abandoned if appropriate) including any cement bond logs available. Assurance as to the adequacy of the plugging of abandoned wells is essential.

A corrective action plan shall be developed for those wells that are considered to be high risk for leakage (i.e., poor condition of cement, poor maintenance, and penetrating the oil reservoir and confining zones). The corrective action plan may involve either remediation or monitoring for leakage at the well.

Good well construction and completion are important to prevent leakage. All CO<sub>2</sub> injection wells used for EOR operations in the US meet Class II well requirements outlined by the USEPA underground injection control (UIC) program.<sup>45</sup> There may be additional State requirements that affect the construction, completion, operation, and testing of Class II wells. Operators shall comply with all applicable State rules affecting Class II wells. As an example, standards and procedures for Class II well operation in the State of Texas are discussed in Appendix C.

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<sup>45</sup> USEPA, 40CFR Part 146, Underground Injection Control Program: Criteria and Standards

#### *5.4.1.3 Monitoring Strategy*

The monitoring strategy shall be geared to demonstrate effective retention of the injected anthropogenic CO<sub>2</sub> within the storage volume during and after injection. Based on site evaluation and geological parameters in the storage volume, simulations of potential failure scenarios that include a range of uncertainty in modeled parameters and site characteristics shall be developed. Based on the sensitivities of individual parameters to the outcomes of those simulations, the Project Proponent shall determine the specific monitoring parameters to be monitored, the monitoring tools to be used, and the sampling frequency.

A fluid flow model is an essential component of the monitoring strategy. Working with the EOR operator, required data (existing and newly collected) shall be compiled to develop a fluid flow model that is calibrated with production history and used to predict CO<sub>2</sub> distribution during the injection and post-injection phases of the EOR project. To update and compare the model results, material balances for total field CO<sub>2</sub> injection, resulting from purchased CO<sub>2</sub> and recycled CO<sub>2</sub> (CO<sub>2</sub> recovered from oil production and re-injected into the reservoir), as well as any water injected, shall be maintained. The observed material balances for fluids (oil, gas, water, CO<sub>2</sub>) shall be compared to the fluid production predicted by the model.

If EOR operators are already required to perform certain test procedures as part of meeting regulatory requirements, then those procedures shall be incorporated into the project's MRV. For example many State regulators require periodic Mechanical Integrity Tests (MITs) to assure well integrity. These activities can help in the early detection of CO<sub>2</sub> leakage out of the injection zone and allow for remedial actions to be taken in a timely manner, thereby reducing the probability of atmospheric leakage from well bores.

Monitoring shall be designed so that it is sensitive to the leakage signal. Project Proponents shall select and locate monitoring equipment and establish CO<sub>2</sub> detection thresholds to calibrate monitoring systems in a manner that provides confidence in the monitoring program's ability to accurately confirm the effectiveness of CO<sub>2</sub> storage. The data collected shall test the correctness of key modeling assumptions. The Project Proponent shall identify key project-specific parameters that are indicative of leakage and determine appropriate ranges for those parameters, such that exceedances are indicative of leakage.

Depending on site-specific conditions, the Project Proponent shall determine whether the monitoring approach would benefit from establishing pre-injection levels. If deemed beneficial, these measurements shall be done for a period of time that allows for the collection of data that are



representative of site conditions prior to the initiation of injection. On-going research on pre-injection monitoring techniques and approaches can be used as a valuable resource to develop a project-specific monitoring plan. Innovative strategies to determine sources of groundwater contamination in the absence of pre-injection data, which include the use of stable carbon isotopic signatures, noble gases, and other metrics like hydrogen carbonate can be adopted for brownfield sites.<sup>46</sup> The results of on-going research on soil monitoring can provide data to determine its value in a pre-injection monitoring approach.<sup>47</sup>

#### *5.4.1.4 Post Injection Monitoring*

Following completion of CO<sub>2</sub> injection, monitoring shall be maintained during the post-injection phase until the end of the Project Term to assure no atmospheric leakage. The absence of atmospheric leakage during the Project Term is considered assured when it can be verified that no migration of injected CO<sub>2</sub> is detected across the boundaries of the storage volume and the modeled failure scenarios all indicate that the CO<sub>2</sub> will remain contained within the storage volume. 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 reservoir conditions, the pressures within the reservoir should equilibrate and the movement of CO<sub>2</sub> within the reservoir should stabilize. Therefore minimal lateral movement is expected and tracking of the lateral extent of the CO<sub>2</sub> plume through appropriate measurements (such as pressure) and modeling will be adequate. Due to buoyancy effects, the CO<sub>2</sub> plume will tend to migrate to the upper regions of the reservoir where it will be constrained by the caprock. Therefore changes in these subsurface measurements made above the confining zone may be indicative of potential leakage.

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 they are consistent with expected changes or are indicative of leakage. Other monitoring tools shall be implemented in accordance with the site's monitoring plan to assure no leakage. Although atmospheric leakage has not necessarily occurred if the CO<sub>2</sub> migrates to regions outside the storage volume boundaries, it cannot be verified that no leakage has occurred and additional steps are necessary in this case. Project Proponents shall redefine the boundaries of the storage volume. For example, if there is evidence of lateral movement outside the boundaries of the storage volume, then the lateral boundaries shall be extended to regions beyond the original storage volume. However, Project Proponents shall evaluate for the possibility of any new potential atmospheric leakage pathways and

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<sup>46</sup> <http://184.106.226.121/uploads/File/PDFs/Kerr%20Report%20all%20sections-revised%20May%2023-PDF.pdf>

<sup>47</sup> <http://www.beg.utexas.edu/gccc/forum/codexhome.php>

either remediate them and/or modify the monitoring strategy to detect for leakage under new failure scenarios. The duration of post-injection monitoring shall be extended beyond 5 years if no leakage cannot be assured at the end of the 5-year period. In this case, the Project Term will be extended in two-year increments and monitoring shall be continued until no leakage is assured.

#### *5.4.1.5 Post-Project Term requirements for storage of CO<sub>2</sub>*

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<sub>2</sub> 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<sub>2</sub> storage volume is located. The Risk Mitigation Covenant shall apply to any activity occurring on or under the land, 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 planned activity that results in the release of the stored CO<sub>2</sub> including as a collateral effect of future hydrocarbon development (i.e., a reversal) unless measures are taken in advance to compensate for the reversal by replacing the reversed offset credits 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 results in a reversal, 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<sub>2</sub> and the pore space comprising the CO<sub>2</sub> storage volume, which lien shall be included in the Risk Mitigation Covenant.

In the event that the Project Proponent is not the owner of the pore space comprising and/or surface interests overlying the CO<sub>2</sub> 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<sub>2</sub> 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 offset credits for ACR's retirement pursuant to a plan acceptable to ACR (b) the agreement

to notify ACR 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 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 offset credits for the GHG project other than offset credits subject to Invalidation. If a Project Proponent does not provide a Risk Mitigation Covenant or an alternative risk mitigation assurance as described above, the offset credits issued by ACR for the project shall be subject to Invalidation; provided however, offset credits subject to Invalidation may be exchanged for offset credits that are not subject to Invalidation in the event the Project Proponent provides ACR with a Risk Mitigation Covenant or alternative risk mitigation assurance satisfying the requirements of this Section 5.4.1.

The obligations of the Project Proponent and any pore space or surface owner under the Risk Mitigation Covenant or alternative risk mitigation assurance shall cease upon demonstration to the reasonable satisfaction of ACR, as evidenced by a written acknowledgement by ACR, that the federal government or the applicable state government has assumed ownership of and monitoring responsibility for the stored CO<sub>2</sub> by the Project Proponent. Any pore space or surface owner shall be relieved of intentional reversal mitigation requirements for any intentional reversal occurring after such government assumption. ACR's written acknowledgement shall be in 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 risk mitigation assurance.

#### *5.4.1.6 Quantification of Atmospheric Leakage*

The project monitoring plan shall include a strategy for quantifying any atmospheric leakage of CO<sub>2</sub> from the storage volume. In the event that leaks from the storage volume do happen, which are not remediated in time to prevent atmospheric leakage, Project Proponents shall quantify the CO<sub>2</sub> 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 geologic reservoir, the CO<sub>2</sub> injection regime, modeling assumptions, and other variables. The EOR field operator has the best knowledge of site-specific conditions and shall combine this knowledge with sound engineering practices to estimate atmospheric leakage, should it 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 leakage can be used, rather than requiring rigorous quantification.

### 5.4.2 MRV Plan Reporting Requirements

Besides the normal GHG Project Plan reporting requirements specified by ACR, CCS projects shall also include a site-specific MRV plan, which is subject to independent third party validation by a CCS expert on the VVB team (see below). It shall include:

- Description of the reservoir where CO<sub>2</sub> is injected.
- Description of model, including key model parameters and their uncertainties, potential failure scenarios evaluated, and simulation results to determine the extremities of the storage volume that is expected to contain the injected CO<sub>2</sub> through the end of the Project Term.
- Site characterization of the storage volume, including identification of potential leakage pathways and any remediation activities undertaken to reduce potential for leakage.
- Monitoring strategy, including monitoring procedures and tools, and monitoring frequency. A range of expected values for monitored parameters that indicate normal operation and that containment is successful. Note: there may be changes to monitoring strategy as the injection proceeds. The Project Proponent shall document and report changes and the revisions shall be subject to review by the VVB at the next verification interval or next validation (in the case of Crediting Period renewal), whichever comes first.
- If leakage is detected, remedial actions taken to rectify the source of leakage, and/or estimates of atmospheric leakage and how it was mitigated.

It is required that the project-specific MRV Plan be developed by a professional with demonstrated experience and knowledge of design and implementation of systems for monitoring geologic storage of CO<sub>2</sub>, along with expertise in an earth science discipline relevant to monitoring, such as reservoir engineering, geophysics, geology, hydrology, geomechanics, geochemistry, or other relevant discipline. Demonstrated experience/knowledge shall be evidenced by at least three years' experience in monitoring of CO<sub>2</sub>-EOR projects, and/or by published, relevant peer-reviewed academic research on monitoring of CO<sub>2</sub> storage. The curriculum vitae of this professional will be reviewed by ACR and the VVB to confirm that he/she meets the above requirements.

### 5.4.3 MRV Plan Validation and Verification Requirements

Validation of the MRV plan shall be conducted by a competent third party Validation and Verification Body (VVB) with in-house or subcontracted CCS expertise meeting the requirements below. The VVB shall determine the adequacy of the MRV plan to meet the storage goals. It includes verification of the model used; model parameters, assumptions and uncertainties; failure scenarios evaluated; and the adequacy of the monitoring strategy to detect leakage out of the storage volume. The VVB shall also review the EOR operator's injection permit and verify that the site remained in compliance during the reporting year. In instances of non-compliance, the VVB shall determine whether it affects the ERs

claimed and the potential to affect future ERs or compromise long-term storage. The review shall also include a comparison of the MRV Plan with existing protocols and regulations.

The project-specific MRV Plan must be independently validated by a professional with demonstrated experience and a high degree of knowledge of design and implementation of systems for monitoring geologic storage of CO<sub>2</sub>, along with expertise in an earth science discipline relevant to monitoring, such as reservoir engineering, geophysics, geology, hydrology, geomechanics, geochemistry, or other relevant discipline. Demonstrated experience/knowledge shall be evidenced by at least three years' experience in monitoring of CO<sub>2</sub>-EOR projects, and/or by published, relevant peer-reviewed academic research on monitoring of CO<sub>2</sub> storage.

This professional shall be an independent third party serving as part of the VVB team. He/she may be a subcontractor to the VVB as long as the VVB accepts full responsibility for his/her work through their role as signatory of all validation and verification opinions. He/she shall be subject to the VVB's project-specific Conflict of Interest evaluation.

The project-specific MRV Plan must be approved by this professional at the time of initial validation. Subsequent verifications must also be reviewed by this professional, or a professional meeting the same qualifications, to ensure that the project-specific MRV Plan is being adhered to in every reporting period when credits are claimed. Subsequent validations (on Crediting Period renewal every ten years) shall also include review by this professional, or a professional meeting the same qualifications, of any changes to the MRV Plan.

The validation of the initial MRV Plan and subsequent validations and verifications must also be signed off by a registered Professional Engineer (PE) or geologist, who may be (but is not required to be) the same individual as the professional described above.

## 5.5 Measurement Techniques

Volumetric flow rates will be measured by commercially available devices that measure the mass or volumetric rate of 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. The devices shall be installed and calibrated in accordance with manufacturer's specifications. The flow meter 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. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the

American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB). Flow meter calibrations performed shall be National Institute of Standards and Technology (NIST) traceable.

Gas or liquid composition analysis shall be measured by an appropriate standard method published by a consensus-based standards organization, if such a method exists, or an industry standard practice.

Flowrate measurements are made continuously, where continuous measurement is commonly defined as one measurement every 15 minutes or less. The CO<sub>2</sub> concentration in the gas stream is measured at monthly intervals.

Monitoring methods for MRV of geologic storage sites are discussed in USDOE and USEPA documents and are also contained in certain State regulations.<sup>48,49,50,51</sup>

## 5.6 Data and Analysis for Verification

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 4.0. Project Proponents shall incorporate this information into their project-specific MRV Plan and adapt it to accommodate the specific conditions associated with their CCS project.

To ensure the validity of GHG reduction claims, data collection and monitoring is essential. Table 5-3 aggregates the specific monitoring parameters and activities needed for a comprehensive assessment of the GHG reductions that might be claimed by a Project Proponent. Project Proponents shall take into account the location, type of equipment and frequency of measurement for each variable.

In addition to the parameters in Table 5-3, project proponents shall report the results of the MRV measurements discussed in Section 5-4.

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<sup>48</sup> Best Practices for: Monitoring, Verification, and Accounting of CO<sub>2</sub> Stored in Deep Geologic Formations, DOE/NETL-311/081508, January 2009, [www.netl.doe.gov/technologies/carbon\\_seq/refshelf/MVA\\_Document.pdf](http://www.netl.doe.gov/technologies/carbon_seq/refshelf/MVA_Document.pdf)

<sup>49</sup> Best Practices for: Monitoring, Verification, and Accounting of CO<sub>2</sub> Stored in Deep Geologic Formations – 2012 Update, DOE/NETL-2012/1568, October 2012, [http://www.netl.doe.gov/technologies/carbon\\_seq/refshelf/BPM-MVA-2012.pdf](http://www.netl.doe.gov/technologies/carbon_seq/refshelf/BPM-MVA-2012.pdf)

<sup>50</sup> General Technical Support Document for Injection and Geologic Sequestration of Carbon Dioxide: Subparts RR and UU Greenhouse Gas Reporting Program, (Chapter 4 & 5), USEPA, (2010) [www.epa.gov/climatechange/emissions/downloads10/Subpart-RR-UU\\_TSD.pdf](http://www.epa.gov/climatechange/emissions/downloads10/Subpart-RR-UU_TSD.pdf)

<sup>51</sup> Fluid Injection in Productive Reservoirs, Texas Administrative Code (TAC), Title 16, Part 1, RULE §3.46

The EOR site must remain in compliance with its permit conditions through the injection monitoring period. EOR site operators shall produce documentation indicating that their site has been in regulatory compliance. If there are periods of non-compliance then the date(s) and nature of non-compliance, remedial actions taken, and the date(s) when the site returns to being in 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.

Table 5-3 Monitoring Parameters<sup>52</sup>

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
<b>Projection-Based Baseline</b>					
<b>Vol.</b> Gas Produced	Total volume of gas (containing CO <sub>2</sub> and other compounds) produced from the primary process in the project condition, metered continuously at a point immediately downstream of the primary process, measured at standard conditions, in year y.	m <sup>3</sup> /yr	[m]	Continuous	Continuous measurement of the volume of gas produced from the primary process, where continuous measurement is commonly defined as one measurement every 15 minutes or less.  Flow meters shall be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer.
<b>%CO<sub>2</sub></b>	% CO <sub>2</sub> in the gas stream from the primary process in the project condition, measured immediately downstream of the primary process, in each year.	% CO <sub>2</sub> by volume	[m]	Monthly	Direct measurement of the composition of the gas stream on a monthly basis.  Gas analyzers shall be calibrated in accordance with manufacturer's specifications.

<sup>52</sup> Based on A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects, Center for Climate and Energy Solutions, February, 2012.



Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
<b>Standards-Based Baseline</b>					
<b>Output</b>	Units of output from the CO <sub>2</sub> capture facility (e.g., MWh) in the project condition in year y.	Units of output (e.g., MWh)	[m]	Daily	<p>Measurement based on the type of primary process. Output shall be measured to account for the total output from the primary process that would have occurred in the absence of the project.</p> <p>Measurement devices shall be calibrated in accordance with manufacturer's specifications.</p>
<b>Non-Captured CO<sub>2</sub> Emissions from the Primary Process</b>					
<b>Vol. Gas Produced</b>	Total volume of gas (containing CO <sub>2</sub> and other compounds) produced from the primary process, metered continuously at a point immediately downstream of the primary process, measured at standard conditions, in year y.	m <sup>3</sup> /yr, scf/yr	[m]	Continuous	<p>Continuous measurement of the volume of gas produced from the primary process, where continuous measurement is commonly defined as one measurement every 15 minutes or less.</p> <p>Flow meters shall be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer.</p>

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
<b>%CO<sub>2</sub></b>	% CO <sub>2</sub> in the gas stream from the primary process, measured immediately downstream of the primary process, in year y.  % CO <sub>2</sub> in the captured gas stream, measured at the input to the pipeline, in year y	% CO <sub>2</sub> by volume	[m]	Monthly	Direct measurement of the composition of the gas stream on a monthly basis  Gas analyzers shall be calibrated in accordance with manufacturer's specifications.
<b>Fuel i</b>	Volume or mass of each type of fuel, by fuel type i, burned by combusted by the primary process in year y.	Liters, gallons, m <sup>3</sup> , scf, metric tons	[m], [o]	Daily or monthly	For gaseous fuels, daily measurement of the gas flow rate.  Flow meters used to measure the volume of gas shall be calibrated according to manufacturer specifications.  For liquid and solid fuels monthly reconciliation of purchasing records and inventory adjustments as needed.  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 fossil fuels consumed to operate the CCS systems.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
<b>Vol. Gas Transferred</b>	Volume of gas (containing primarily CO <sub>2</sub> ) captured and input into the pipeline, metered at the point of transfer with the pipeline (or equivalent), measured at standard conditions, in year y.	m <sup>3</sup> /yr, scf/yr	[m]	Continuous	Continuous measurement of the volume of gas captured from the primary process and input into the pipeline, where continuous measurement is commonly defined as one measurement every 15 minutes or less.
<b>Stationary Combustion Emissions for CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O</b>					
<b>Fuel i</b>	Volume of each type of fuel, by fuel type i, used to operate each component (capture, transport, and storage) of the CCS project in year y.	m <sup>3</sup> , scf, Liter, gallons, metric tons	[m], [o]	Daily, monthly	<p>For gaseous fuels, daily measurement of the gas flow rate.</p> <p>Flow meters used to measure the volume of gas shall be calibrated according to manufacturer specifications.</p> <p>For liquid and solid fuels monthly reconciliation of purchasing records and inventory adjustments as needed.</p> <p>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 fossil fuels consumed to operate the CCS project.</p>

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
<b>Indirect CO<sub>2</sub> Emissions from Purchased and Consumed Electricity, Steam, Heat</b>					
<b>Electricity</b>	Metered electricity usage from equipment used to operate electrically driven component (capture, transport, and storage) in the CCS project in year y.	MWh	[m], [o], [c]	Continuous or monthly	<p>Continuous measurement of electricity consumption or monthly billing records from utility supplier, or reconciliation of maximum kW rating for each type of equipment and operating hours. Electricity meters shall be calibrated by an accredited party per manufacturer's specifications.</p> <p>Electricity consumption shall be metered continuously wherever possible for the CCS project. However, in certain cases other loads may be tied into the same electricity meter and estimates may be required. In these cases the maximum kW rating of each piece of equipment could be used in conjunction with a conservative estimate of operating hours (e.g., 8760 hours per year) to estimate the electricity consumption.</p> <p>Electricity usage can also be determined from monthly bills received from the utility.</p>
<b>Total Fuel Cogen</b>	Total volume or mass of each type of fuel, by fuel type i, combusted by the third party cogeneration unit supplying electricity or thermal energy to the CO <sub>2</sub> capture and compression facilities in year y.	Liters, gallons, m3, scf, metric tons	[m], [o]	Daily, monthly	Daily metering of gaseous fuels or monthly reconciliation of volumes or masses for liquid or solid fuels purchased and in storage.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
<b>Heat CCS Project</b>	Quantity of thermal energy purchased from the third party cogeneration unit to operate the CO <sub>2</sub> capture facilities in year y.	MWh	[m], [o]	Daily or monthly	<p>Daily metering of thermal energy sales/purchases to/for the CCS project using a utility meter. Monthly billing received from the cogen operator showing the quantity and condition of steam can be used to determine steam usage.</p> <p>Steam meters, or similar, shall be calibrated by an accredited party per manufacturer specifications.</p>
<b>Electricity CCS Project</b>	Quantity of electricity purchased from the third party cogeneration unit to operate the CO <sub>2</sub> capture and compression facilities in year y.	MWh	[m], [o]	Daily or monthly	<p>Daily measurement of electricity sales/purchases to/for the CCS project.</p> <p>Monthly billing from the cogen operator can be used to determine electricity usage.</p> <p>Electricity meters shall be calibrated by an accredited party per manufacturer's specifications.</p>
<b>Heat Cogen</b>	Total quantity of process energy (e.g. process steam) generated by the third party cogeneration unit in year y.	MWh	[m], [o]	Daily or monthly	<p>Daily metering of total process energy generated using a utility meter. Steam meters, or similar, shall be calibrated by an accredited party per manufacturer's specifications.</p> <p>Cogen operator's monthly records can be used as source of data.</p>

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
<b>Electricity Cogen</b>	Total quantity of electricity generated by the third party cogeneration unit in year y.	MWh	[m], [o]	Daily or monthly	Daily measurement of total electricity sales/purchases. Electricity meters shall be calibrated by an accredited party per manufacturer's specifications.  Cogen operator's monthly records can be used as source of data.
<b>Vented and Fugitive CO<sub>2</sub> Emissions from CO<sub>2</sub> Transport – Mass Balance</b>					
<b>Vol. Gas Received</b>	Volume of gas (containing primarily CO <sub>2</sub> ) captured and input into the pipeline, metered at the point of transfer with the pipeline (or equivalent), measured at standard conditions, in year y.	m <sup>3</sup> /yr, scf/yr	[m]	Continuous	Continuous measurement of the volume of gas captured from the primary process and input into the pipeline, where continuous measurement is commonly defined as one measurement every 15 minutes or less.  Flow meters shall be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer.
<b>%CO<sub>2</sub></b>	% CO <sub>2</sub> in the gas stream being transported by pipeline, measured at the input to the pipeline, in year y.	% CO <sub>2</sub> by volume	[m]	Monthly	Direct measurement of the composition of the gas stream on a monthly basis.  Gas analyzers shall be calibrated in accordance with manufacturer's specifications.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
<b>Vol.</b> Gas Supplied	Total volume of gas (containing primarily CO <sub>2</sub> ) supplied to the storage site operator, metered at the point of transfer between pipeline (or equivalent) and CO <sub>2</sub> storage site, measured at standard conditions, in year y.	m <sup>3</sup> /yr, scf/yr	[m]	Continuous	Continuous measurement of the volume of gas delivered to the CO <sub>2</sub> storage site, where continuous measurement is commonly defined as one measurement every 15 minutes or less.  Flow meters shall be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer.
<b>Vented and Fugitive CO<sub>2</sub> Emissions from CO<sub>2</sub> Storage</b>					
<b>N</b> <sub>Blowdown i</sub>	Number of blowdowns (venting events) from specific equipment at the storage site (e.g., compressors, pressure release valves), obtained from blowdown event logs retained by storage site operator.	#	[o]	NA	Storage site operator shall keep detailed logs of all venting incidents.
<b>V</b> <sub>Blowdown i</sub>	Total volume of blowdown equipment chambers for equipment (including pipelines, manifolds and vessels between isolation valves).	m <sup>3</sup> , scf	[o], [c]	NA	Volume can be estimated based on equipment specifications (pipeline diameters etc.), flow meters, duration of event.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
<b>%GHG<sub>j</sub></b>	Concentration of GHG (CO <sub>2</sub> or CH <sub>4</sub> ) in the injected or produced gas (volume percent CO <sub>2</sub> or CH <sub>4</sub> , expressed as a decimal fraction).	%	[m]	Monthly	Direct measurement of the composition of the gas stream on a monthly basis.  Gas analyzers shall be calibrated in accordance with manufacturer's specifications.
<b>Count<sub>s</sub></b>	Total number of each type of emission source at the injection wellheads and at surface facilities located between the point of transfer from the CO <sub>2</sub> pipeline and the injection wells in the formation.	#	[o]	NA	Storage site operator shall develop and maintain an equipment inventory to identify all possible fugitive emission sources from surface facilities at the storage site.
<b>T<sub>s</sub></b>	Total time in hours that the equipment associated with the each fugitive emission source was operational.	Hours	[o]	NA	Estimated based on operational records of downtime at the injection wells, storage site and hydrocarbon production facilities.
<b>Vol. Gas Sold</b>	Volume of natural gas or fuel gas, produced from the formation that CO <sub>2</sub> is being injected into, that is sold to third parties or input into a natural gas pipeline in year y.	m <sup>3</sup> , scf	[m]	Daily	Continuous metering of sales volumes of natural gas.
<b>% CO<sub>2</sub> Gas Sold</b>	% CO <sub>2</sub> in the natural gas or fuel gas that is sold to third parties or input into a natural gas pipeline, in year y.	%	[m]	Annual	Direct measurement of the composition of the natural gas at the sales meter.



Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
<b>Mass</b> <sub>Water Prod</sub>	Mass of water produced from the formation that CO <sub>2</sub> is being injected into, that is disposed of or otherwise not-re-injected back into the formation.	Metric tons	[o]	Monthly	Monthly reconciliation of water disposal records.
<b>Mass Frac</b> <sub>CO<sub>2</sub> in Water</sub>	Mass fraction of CO <sub>2</sub> in the water produced from the formation.	-	[m]	Annual	Conduct lab analysis of composition of produced water. Report dissolved inorganic carbon species.
<b>Mass</b> <sub>Oil Prod</sub>	Mass of crude oil and other hydrocarbons produced from the formation into which CO <sub>2</sub> is being injected.	Metric tons	[m]	Monthly	Reconciliation of hydrocarbon sales from facilities associated with the producing formation.
<b>Mass Frac</b> <sub>CO<sub>2</sub> in Oil</sub>	Mass fraction of CO <sub>2</sub> in the crude oil and other hydrocarbons produced from the formation.	-	[m]	Annual	Conduct lab analysis of composition of crude oil
<b>CO<sub>2</sub> Transferred Offsite</b>					
<b>Vol</b> <sub>CO<sub>2</sub>_Transfer</sub>	Volume of produced CO <sub>2</sub> from an EOR operation transferred outside project boundary in each year.	m <sup>3</sup> , scf	[m]	Monthly	Projects Proponent shall deduct from quantified reductions “produced CO <sub>2</sub> ” that is not reinjected but transferred offsite. Measured at a point to account for total volume not reinjected.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
<b>Atmospheric Leakage of CO<sub>2</sub> from Storage</b>					
CO <sub>2z</sub>	Total mass of CO <sub>2</sub> emitted through leakage pathway z to atmosphere in year y.	Metric tons	[c]	NA	<p>In the event that leakage from the geologic reservoir to the atmosphere occurs, the mass of CO<sub>2</sub> that has escaped would be estimated based on monitoring and measurements completed as part of the CCS project's MRV plan.</p> <p><u>Note:</u> This does not include fugitive CO<sub>2</sub> emissions from wells, which are calculated according to Equation 4.16.</p>

## 6.0 EMISSIONS OWNERSHIP AND QUALITY

### 6.1 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.

### 6.2 Title

Since CCS projects involve capture, transport, and sequestration processes, which are often conducted by different companies, the ownership to the title of CO<sub>2</sub> credits associated with the project's emission reductions 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.

During the operational phase, documentation that traces the chain of custody of CO<sub>2</sub> as it is transferred from parties involved in the capture, transport, and sequestration processes shall be established. This includes documents indicating the date (month/yr), CO<sub>2</sub> volumes sold by the supplier, transported, and received by the EOR operator. The documentation shall be maintained by the Project Proponent and provided during verification. The documents shall be retained for a minimum period of 3 years following the end of the crediting period.

### 6.3 Permanence, Liability, and Mitigation

For CCS projects, Project Proponents must demonstrate that the CO<sub>2</sub> captured and stored is permanently sequestered underground. The post-injection monitoring tasks as described in Section 5.4 will be conducted for the Project Term defined in Section 2.2. Post-Project Term requirements are described in Section 5.4.1. Site characterization coupled with the use of site-specific monitoring and modeling 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<sub>2</sub> 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 5.4, no leakage is assured when it can be verified that no migration of injected CO<sub>2</sub> is detected across the boundaries of the storage volume and the modeled failure scenarios all indicate that the CO<sub>2</sub> will remain contained within the storage volume.

An operator shall prove financial responsibility prior to gaining a permit to begin active 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. Appendix D includes a listing of laws that have been enacted and/or bills that are currently pending in the State legislatures at the time of publication of the methodology related to liability and pore space ownership issues in CCS projects.

Long-term liabilities arise from migration of the CO<sub>2</sub> plume, either vertically through well bores, fractures, or faults or horizontally by moving to points of leakage. 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<sub>2</sub> plume in the reservoir increases over years of MRV operations.

Migration of CO<sub>2</sub> 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 (Texas Railroad Commission v. Manziel)<sup>53</sup>, which held that injection associated with a state-authorized secondary recovery project would not cause trespass. This was decided even though fluids move across property lines. In other States, this issue would be dependent on individual State regulations and statutes.

While the lateral migration of CO<sub>2</sub> outside the confining zone 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 is no leakage to the atmosphere.

If a CO<sub>2</sub>-EOR project has a leak which causes damage, the operating Company may be liable in criminal or civil courts. Case law has built up around claims associated with subsurface injection and liabilities can be managed through the existing legal system. To cover liability of atmospheric leakage, Project Proponents can purchase private insurance designed to cover damages associated with releases, including third-party liability and liability to ACR, and those resulting from lost credits due to reversals. Insurance premiums would be paid by the Project Proponent to the insurance company, and, in the event of CO<sub>2</sub> leakage to the atmosphere, the insurance company would cover obligations to compensate for reversals in GHG emissions reductions (e.g., purchase and retire ACR offset credits).

In lieu of insurance, Project Proponents may opt to create a Reserve Account. Each year the Project Proponent would deposit 10 (ten) percent of the project's offset credits in the Reserve Account. In the event of reversals, a debit shall be measured and reported, verified, and reconciled by the Account by retiring offset credits from the Reserve Account. 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 ACR offset credits of any type and vintage.

If atmospheric leakage occurs, remediation will be conducted in accordance with the site-specific remediation plan, and any leaks to the atmosphere shall be estimated and mitigated. The procedures for mitigation of atmospheric leakage during the injection and post-injection periods are summarized in Table 6-1. If a small release (i.e., less than the estimated ERs for that year) occurs during the injection period and results in leakage to the atmosphere, then it shall be mitigated as project emissions in the same year using Equation 4-19. If the release is large and exceeds the ERs for that year, then a portion of

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<sup>53</sup> Railroad Commission of Texas v. Manziel, 361 S.W. 2d 560 (Tex. 1962)

that release is mitigated as project emissions until ERs for that year are zero. The remaining release (i.e., unreconciled quantity) shall be compensated by liability insurance, or be reconciled through the retirement of an equivalent quantity of offset credits from the project's Reserve Account.

**Table 6-1 Atmospheric Leakage Mitigation Procedures**

Atmospheric Leakage Scenario	Required Mitigation
<b>Project Term</b>	
<b>Injection Period:</b> Leakage detected in year “y”. where $y \leq n$ “n” = total years of injection	Handle as project emissions in year y using Eq. 4.19. If leakage exceeds year y ERs, then reconcile as project emissions in year y until GHG ER <sub>y</sub> = 0 (Eq. 4.21), and excess leakage (i.e., unreconciled leakage) is mitigated by one of the following options: <ol style="list-style-type: none"> <li>1. Use private insurance acceptable to ACR (see note), or</li> <li>2. Upon offset credit issuance, contribute 10 % of the project's ERs/year or an equivalent quantity of ACR offset credits (of any type and vintage) into a Reserve Account; ACR will retire quantity to be mitigated from the Account.</li> </ol>
<b>Post Injection Period:</b> Leakage detected in year “y” where $y > n$ . “n” = total years of injection	Project Proponent shall choose one of the following options: <ol style="list-style-type: none"> <li>1. Use private insurance acceptable to ACR (see note), or</li> <li>2. Upon offset credit issuance, contribute 10 % of the project's ERs/year or an equivalent quantity of ACR offset credits (of any type and vintage) into a Reserve Account; ACR will retire quantity to be mitigated from the Account</li> </ol>
<b>Post Project Term</b>	
A release of stored CO <sub>2</sub> 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 risk mitigation assurance approved by ACR, prior to any release of stored CO <sub>2</sub> as described in the Covenant, ACR must be compensated through replacement deposit of the full amount of offset credits issued to the project during the Project Term, allowing ACR to retire such offset credits. If an intentional or collateral release occurs for a project with offset credits subject to Invalidation, ACR may invalidate such offset credits if replacement offset credits are not deposited for retirement by ACR.
<i>Note: Any private insurance policy must be evaluated and approved by ACR to make sure there are no exclusions, term limitations, or liability limits that leave ACR exposed. Only once ACR accepts the insurance product will ACR waive contributions to the Reserve Account.</i>	

If atmospheric leakage occurs during the post-injection period, then the Project Proponent shall mitigate the leaked quantity by liability insurance or by the retirement of an equivalent quantity of offset credits from the project's Reserve Account.

Project Proponents shall indicate their mitigation strategy (i.e., insurance or Reserve Account) in their GHG Project Plan. If Project Proponents choose to mitigate by insurance, then that insurance product must be approved by ACR as indicated in Table 6-1. If Project Proponents choose to mitigate by contributions to an Reserve Account, those contributions shall begin from the start of offset crediting and shall constitute 10% of the project's ERs each issuance, or an equivalent quantity of ACR offset credits (of any type and vintage).

In the event that atmospheric leakage exceeds the Reserve Account contributions or the coverage provided by insurance, the Project Proponent shall mitigate any unreconciled quantity through deposit of sufficient ACR offset credits for ACR's retirement (of any type or vintage). If the Project Proponent does not deposit sufficient ACR offset credits to mitigate the leakage within 45 days, then ACR retains the right to freeze the Proponent's project account and retire any existing offset credits to mitigate the unreconciled quantity.

#### 6.4 Pore space ownership

CCS Project Proponents may need to own or obtain rights to the subsurface pore space where CO<sub>2</sub> 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, generally is 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 injection of fluids into deep geological formations. Such injection under the underground injection control (UIC) program goes on without approval from surface land owners 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-labile 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 whoever is able to assert them physically on a first-come basis.<sup>54</sup>

As indicated in Appendix D, while pore space ownership issues are beginning to be addressed through State law and regulation, those laws 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.

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<sup>54</sup> Carbon Capture and Sequestration: Framing the Issues for Regulation, CCSReg Interim Report, January 2009

In the case of CO<sub>2</sub> EOR projects, the right to inject CO<sub>2</sub> into the subsurface oil reservoir generally is 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<sub>2</sub> during the operational phase of a CO<sub>2</sub> EOR project would be permissible under an oil and gas lease.<sup>55</sup> Once injected and secured in the reservoir, the operator is not required to extract the injected CO<sub>2</sub> at the completion of the operational phase of the project.

Migration of any injected fluid is only permissible provided the migration is in compliance 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.<sup>56</sup>

In the case of EOR, it is typical that mineral lease rights and associated surface use rights expire following the end of hydrocarbon production activities. However, monitoring after the end of hydrocarbon extraction activities is needed as part of assuring no atmospheric leakage (Section 5.4). Project Proponents shall ensure that EOR operators have continued access to the surface to conduct post-injection monitoring activities and if necessary, remediation. Based on the site-specific monitoring planned for the post-injection period and associated surface access requirements, Project Proponents shall obtain needed surface use 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 remediation activities. Further, as required by Section 5.4.1, Project Proponents shall obtain the consent of surface owners to the filing of a Risk Mitigation Covenant or provide an alternative risk mitigation assurance acceptable to ACR, and if it does not do so, the offset credits issued for the project shall be subject to Invalidation.

## 6.5 Community and Environmental Impacts

CCS projects involve the installation of capture technologies, pipelines and gas separation and compression infrastructure. These CCS projects are capital-intensive and may require environmental assessments. If an Environmental Assessment (EA) or an Environmental Impact Statement (EIS) is required, that document or a summary thereof shall be provided to ACR and provided to the VVB on request. There are different state and federal laws, regulations and guidance that require an EA or EIS for certain government actions, such as the federal Environmental Policy Act (NEPA) and state analogues. Project Proponents shall document in the GHG Project Plan a mitigation plan for any foreseen negative community or environmental impacts, and shall disclose in their annual Attestations any negative environmental or community impacts or claims of negative environmental and community impacts made during the reporting year. These claims include legal actions and/or other written complaints filed by affected parties.

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<sup>55</sup> Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces, IOGCC, 2007.

<sup>56</sup> Carbon Capture and Sequestration: Framing the Issues for Regulation, Interim Report, CCSReg Project, January 2009

## 7.0 QA/QC

QA/QC procedures shall be implemented during all phases of the project to assure data quality and completeness. The USEPA has published Mandatory Greenhouse Gas Reporting requirements for various types of facilities that emit GHG.<sup>57</sup> General Provisions are contained in Subpart A. This methodology incorporates the requirements contained in Part 98.3(i) of Subpart A, *Calibration Accuracy Requirements*, which requires all measurement devices be calibrated according to the manufacturer's recommended procedures or an appropriate industry consensus standard to an accuracy of 5 percent. Calibration records shall be maintained and made available to third party verification.

For flow meters, all calibrations shall be performed at measurement points that are representative of normal operation of the meter. Except for the orifice, nozzle, and venturi flow meters (which are described in the next paragraph of this section), the calibration error at each measurement point is calculated using Equation 7-1. The terms "R" and "A" in Equation 7-1 must be expressed in consistent units of measure (e.g., gallons/minute, ft<sup>3</sup>/min). The calibration error at each measurement point shall not exceed 5.0 percent of the reference value.<sup>58</sup>

### Equation 7-1: Calibration Error Calculation for Flow Meters

$$CE = (R-A)/R \times 100$$

Where,

**CE** = Calibration Error (%)

**R** = Reference Value

**A** = Flow meter response to the reference value.

For orifice, nozzle, and venturi flow meters, the initial quality assurance consists of in-situ calibration of the differential pressure (delta-P), total pressure, and temperature transmitters. Each transmitter shall be calibrated at a zero point and at least one upscale point. Fixed reference points, such as the freezing point of water, may be used for temperature transmitter calibrations. The calibration error of each transmitter at each measurement point is calculated using Equation 7-2. The terms "R", "A", and "FS" in Equation 7-2 must be in consistent units of measure (e.g., milliamperes, inches of water, psi, degrees). For each transmitter, the CE value at each measurement point shall not exceed 2.0 percent of full-scale. Alternatively, the results are acceptable if the sum of the calculated CE values for the three transmitters at each calibration level (i.e., at the zero level and at each upscale level) does not exceed 5.0 percent.

<sup>57</sup> Mandatory Greenhouse Gas Reporting, USEPA Code of Federal Regulations. 40 CFR Part 98

<sup>58</sup> Mandatory Greenhouse Gas Reporting, USEPA Code of Federal Regulations. 40 CFR Part 98.3(i)



**Equation 7-2: Calibration Error Calculation for Flow Meter Transmitters**

$$CE = (R-A)/FS \times 100$$

Where,

<b>CE</b>	=	Calibration Error (%).
<b>R</b>	=	Reference Value.
<b>A</b>	=	Transmitter response to the reference value.
<b>FS</b>	=	Full scale value of the transmitter.

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 the 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 (USEPA 40 CFR Part 98.3(i)).

The methodology recommends additional procedures as part of the project's QA/QC program. Data collection procedures (templates, logs, etc.) shall be developed to ensure site-specific data are collected in a timely fashion. Periodic reviews of the data for accuracy, completeness and consistency shall be conducted. As appropriate these procedures shall be included in the plant and storage site standard operating procedures (SOPs). If data are missing, the methodology recommends that Project Proponents follow missing data procedures contained in USEPA Subpart RR regulations.<sup>59</sup>

The MRV Plan to detect and assess subsurface leakage (if any) shall include quality checks on the data, models, etc. and report on significant deviations from expected values.

The GHG Project Plan shall include a section on QA/QC plan and procedures that will be followed to ensure data quality and completeness.

<sup>59</sup> USEPA Subpart RR, Geologic Sequestration of Carbon Dioxide, 40 CFR Part 98.445, Procedures for Estimating Missing Data.

## 8.0 UNCERTAINTIES

The emission reduction calculations in this methodology are designed to minimize the possibility of overestimation and over-crediting of GHG emission reductions, due to various uncertainties, primarily associated with fluid flow and composition analysis of gas and liquid streams, plant operating parameters, and accurate logs of emission leakage events maintained by site operators.

While some of these uncertainties are more easily quantified than others, the sources and relative magnitude of uncertainties (and changes thereof) shall be explicitly addressed and discussed by the Project Proponent and described in the GHG Project Plan as part of the GHG emissions calculation and reporting process.

Potential sources of uncertainty and the associated QA/QC program elements designed to minimize them are summarized in Table 8-1. Overall uncertainty can be assessed by using the uncertainties of each element in a calculation.

The accuracy and precision of measurement equipment, such as the flow meters, gas composition analyzers, process measurements (e.g., electricity and steam), are readily quantified and the uncertainties associated with each measurement are considered to be low.

The accuracy and completeness of site operator data on blowdown events and estimates of fugitive emission losses depend on meticulous logs maintained by the operator. The uncertainty in these parameters is considered low since site operators are currently required to report these data to the USEPA as part of their reporting requirements under Subpart W.<sup>60</sup> Operators that are exempt from Subpart W reporting shall follow procedures contained in subpart W to estimate losses from blowdown events and fugitive emissions.

The uncertainty in detection and assessment of leakage from the subsurface to the atmosphere is dependent on the design and implementation of a site's MRV Plan. For EOR sites, the geologic storage site is generally well characterized and modeled. The development of a site-specific MRV Plan, that identifies possible leakage pathways and utilizes a proper set of monitoring tools to provide assurance of containment and to detect leakage, should it occur, is critical. There is a wealth of oil and gas industry experience in the design and implementation of proper monitoring tools, many of which are currently being utilized to optimize production. Based on the implementation of a well-designed MRV Plan, the uncertainty in detection and measurement of leakage is considered low for EOR sites.

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<sup>60</sup> Under Subpart W, owners or operators of facilities that contain petroleum and natural gas systems and emit 25,000 tonnes or more of GHGs per year must report emissions from all source categories located at the facility for which emission calculation methods are defined in the rule. It includes the reporting of venting and fugitive emissions from onshore petroleum and natural gas production facilities, such as EOR operations.

**Table 8-1** Potential Sources of Uncertainty

Data Parameter	Uncertainty Level of Data	Comments
<b>Vol.</b> Gas Produced <b>Vol.</b> Gas Transferred <b>Vol.</b> Gas Received <b>Vol.</b> Gas Supplied <b>Vol.</b> Gas Sold (fuel) <b>Vol.</b> CO <sub>2</sub> _Transfer	Low	<p>Extensive industry experience with flow meters used for this application. Flow meters shall be installed and operated in accordance with manufacturer's specifications.</p> <p>Flow meters shall be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer.</p>
<b>%CO<sub>2</sub></b> <b>% CO<sub>2</sub> Gas Sold (fuel)</b>	Low	<p>Industrial processes producing CO<sub>2</sub> are well controlled so minimal variability of CO<sub>2</sub> concentrations in gas stream.</p> <p>Direct measurement of the composition of the gas stream shall be made on a monthly basis.</p> <p>Gas analyzers shall be calibrated in accordance with manufacturer's specifications.</p>
<b>Output</b>	Low	Measurements based on the type of primary process. Output shall be measured using instrumentation that shall be calibrated in accordance with manufacturer's specifications.
<b>Fuel i</b>  <b>Total Fuel Cogen</b>	Low	<p>For gaseous fuels, daily measurement of the gas flow rate.</p> <p>Flow meters used to measure the volume of gas shall be calibrated according to manufacturer specifications.</p> <p>For liquid and solid fuels monthly reconciliation of purchasing records and inventory adjustments as needed.</p> <p>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 fossil fuels consumed to operate the CCS</p>
<b>Mass Frac.</b> Carbon i	Low	Direct measurement of the carbon content of the fuel using industry accepted practices.
<b>Electricity</b>  <b>Electricity CCS Project</b>  <b>Electricity Cogen</b>	Low	<p>Continuous measurement of electricity consumption using meters calibrated by an accredited party per manufacturer's specifications.</p> <p>If third party utility billing records are used, those measurements are usually based on well calibrated meters. If estimated from maximum kW rating for each type of equipment and operating hours, the uncertainty in energy usage is greater, however the estimates will be conservatively higher.</p>

Data Parameter	Uncertainty Level of Data	Comments
Heat CCS Project Heat Cogen	Low	Daily metering of thermal energy sales/purchases to/for the CCS project using meters calibrated by an accredited party per manufacturer specifications.
$N_{\text{Blowdown } i}$ $V_{\text{Blowdown } i}$	Low	Based on storage site operator's detailed logs of all venting incidents. Volume estimates are based on pipeline diameters and flow conditions and duration of events. Operators are required to log and report these data under federal (USEPA Subpart W) and most State regulations.
$\% \text{GHG}_j$	Low	Direct measurement of the composition of the gas stream on a monthly basis.  Gas analyzers shall be calibrated in accordance with manufacturer's specifications.
$\text{Count}_s$ $T_s$	Low	Storage site operator shall develop and maintain an equipment inventory of all possible fugitive emission sources from surface facilities at the storage site and operational time. Operators are required to report these data to the USEPA per Subpart W requirements. <sup>61</sup>
Mass <sub>Water Prod</sub> Mass <sub>Oil Prod</sub>	Low	Data on water production and injection rates, which are measured with calibrated flow meters, are routinely maintained by operators. Monthly reconciliations of water disposal records are routinely conducted.  Oil or other hydrocarbon production values are based on continuous, daily, or monthly measurements. Data can be obtained from reconciliation of oil or other hydrocarbon sales from facilities associated with the producing formation.
Mass Frac <sub>CO<sub>2</sub> in Water</sub> Mass Frac <sub>CO<sub>2</sub> in Oil</sub>	Low	Data obtained from periodic lab analysis of produced water and produced oil samples using industry accepted practices.
$\text{CO}_{2Z}$	Low	CO <sub>2</sub> leakage (if any) from the geologic reservoir to the atmosphere would be estimated based on monitoring and measurements completed per the CCS project's MRV Plan.  For oil and gas producing reservoirs that have been extensively characterized, modeled, and monitored considering potential failure scenarios, the uncertainty in detecting and estimating leakage is low.

<sup>61</sup> US Environmental Protection Agency. Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, Final Rule: Subpart W. November 30, 2010

## APPENDIX A - ENHANCED OIL RECOVERY OVERVIEW

Crude oil development and production in U.S. oil reservoirs has included three distinct phases: primary, secondary, and tertiary (or enhanced) recovery. After primary and secondary techniques have been used to recover the easy-to-produce oil, producers have attempted several tertiary, or EOR, techniques.

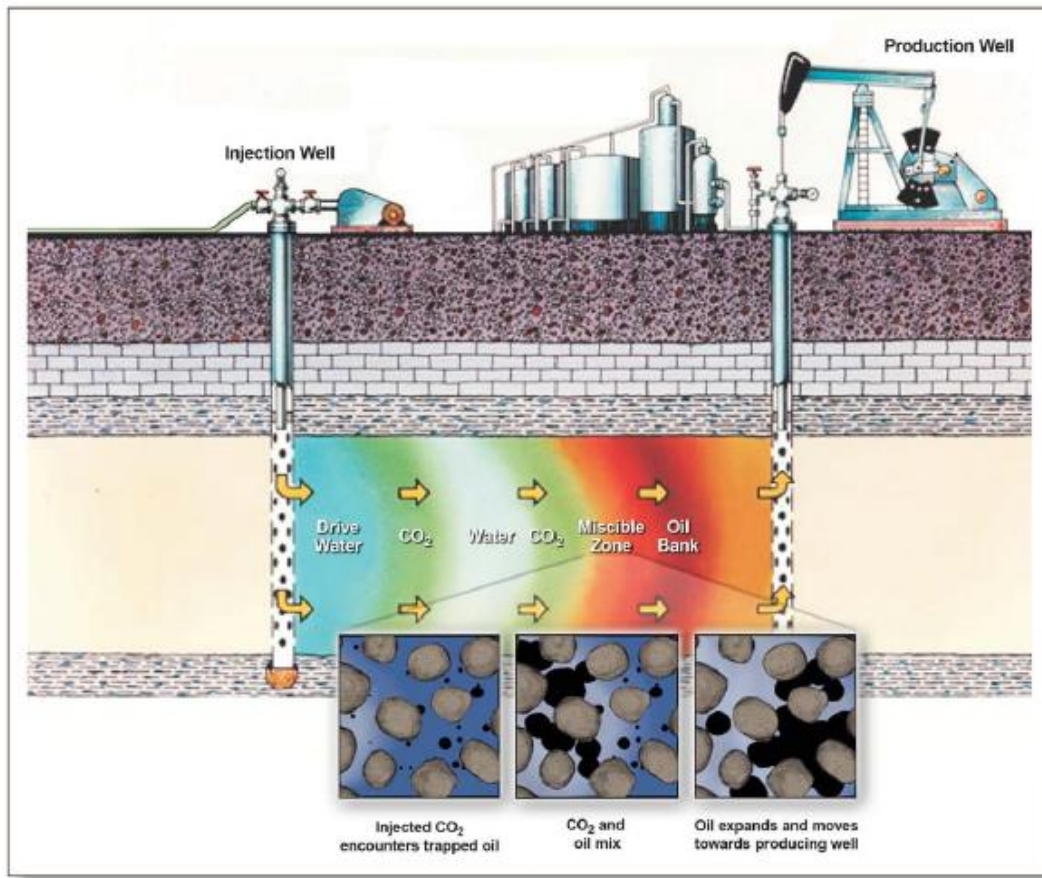
Three major categories of EOR have been found to be commercially successful to varying degrees depending on the oil and reservoir properties and implementation costs:

- Thermal recovery, which involves the introduction of heat such as the injection of steam to lower the viscosity, or thin, the heavy viscous oil, and improve its ability to flow through the reservoir. Thermal techniques account for over 40 percent of U.S. EOR production, primarily in California.
- Gas injection, which uses gases such as natural gas, nitrogen, or carbon dioxide that expand in a reservoir to push additional oil to a production wellbore, or that dissolve in the oil to lower its viscosity and improves its flow rate. A description of CO<sub>2</sub> injection for EOR is included in this section. Gas injection accounts for nearly 60 percent of EOR production in the United States.
- Chemical injection, which can involve the use of long-chained molecules called polymers to increase the effectiveness of waterfloods, or the use of detergent-like surfactants to help lower the surface tension that often prevents oil droplets from moving through a reservoir. Chemical techniques account for about one percent of U.S. EOR production.<sup>62</sup>

The injection of CO<sub>2</sub> into oil reservoirs for EOR has been performed by the oil industry for more than 40 years. CO<sub>2</sub> EOR is based on the concept of miscible or immiscible displacement of oil by CO<sub>2</sub>. A typical CO<sub>2</sub> flood operation is shown in Figure 1. CO<sub>2</sub> is compressed to supercritical conditions and injected into injection wells that are strategically placed within the pattern of wells across the areal extent of the reservoir. The injected CO<sub>2</sub> 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. At the producing wells—and there may be three, four or more producers per injection well—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<sub>2</sub> is separated at the surface. Any produced CO<sub>2</sub> is re-compressed and re-injected along with additional volumes of newly purchased CO<sub>2</sub>. The separated produced water is treated and re-injected, often alternating with CO<sub>2</sub> injection, in a water-alternating-gas (WAG) process.<sup>63</sup>

<sup>62</sup> <http://energy.gov/fe/science-innovation/oil-gas/enhanced-oil-recovery>

<sup>63</sup> Carbon Dioxide Enhanced Oil Recovery, US DOE, NETL, [http://www.netl.doe.gov/technologies/oil-gas/publications/EP/CO2\\_EOR\\_Primer.pdf](http://www.netl.doe.gov/technologies/oil-gas/publications/EP/CO2_EOR_Primer.pdf)



**Figure A-1** Typical EOR process using CO<sub>2</sub> and water in a water-alternating-gas (WAG) process

An operator implementing an EOR project with CO<sub>2</sub> is highly motivated to track and contain all the CO<sub>2</sub> purchased as it is expensive. If the CO<sub>2</sub> is lost out of the producing zone or vented to the atmosphere, the operator will have to purchase additional CO<sub>2</sub>. This means the operator is motivated to design the EOR project to minimize the loss of any CO<sub>2</sub> either in the oil reservoir or in the surface production facilities.

When CO<sub>2</sub> is injected into the reservoir, it is generally injected at a pressure that results in total or partial miscibility with the oil in the reservoir. A portion of CO<sub>2</sub> will become soluble (mixed) with the oil and be recovered when the oil is produced. Of the remaining CO<sub>2</sub> injected, some of the CO<sub>2</sub> will be permanently trapped in the rock's pore space, some will become dissolved in the formation brine, and the remainder will migrate within the reservoir. The CO<sub>2</sub> that is trapped in the rock's pore space is effectively sequestered forever. The CO<sub>2</sub> that is not trapped in the pore space and not mixed with the oil tends to migrate to the upper regions of the oil reservoir, as it is lighter than the oil and water in the formation. However, it remains contained in the oil reservoir because of the confining layer above the oil reservoir that traps it in place. This is the same confining layer that formed an effective seal and contained the oil and gas in the reservoir for millions of years and now serves to trap the CO<sub>2</sub>.

The CO<sub>2</sub> that is produced with the oil will separate from the oil at the surface and be captured. This captured CO<sub>2</sub> is then compressed and re-injected into the oil reservoir where the process starts all over again. The EOR operator maintains tight control over CO<sub>2</sub> at the surface facilities to minimize any losses as it is expensive to lose the CO<sub>2</sub>. In addition, the CO<sub>2</sub> can be effectively measured and monitored while being handled in the surface facilities.

## APPENDIX B- SUPPLEMENTAL QUANTIFICATION METHODS

This appendix provides information on supplemental quantification methods that may be applied to perform CO<sub>2</sub> mass balance calculations, to calculate GHG emissions from electricity usage, to calculate GHG emissions from stationary combustion from fuel use and in situations where a flare is used. Additional guidance on selecting emission factors for fugitive emissions at CO<sub>2</sub> injection, storage facilities and at hydrocarbon production facilities is also provided.

### Additional Guidance on Performing CO<sub>2</sub> mass balances using volume or mass flow measurements

The mass balance equations presented in this methodology rely on continuous measurement of CO<sub>2</sub> at various stages of the CCS project. These flow measurements may be performed using either mass flow meters or volumetric flow meters. All of the calculations in the body of this document rely on volumetric measurements, but alternatively a mass-based measurement may be used. Both mass and volume based measurement approaches are described in the following examples, below. Note that in these illustrative examples, measurements are assumed to be quarterly and other measurement frequencies may be required for CCS projects.

For a mass flow meter, the total mass of CO<sub>2</sub> must be calculated in metric tons by multiplying the metered mass flow by the concentration in the flow, according to the following equations.

#### Equation B-1

$$CO_{2T,x} = \sum_{p=1}^4 (Q_{x,p}) x C_{CO_2,p,x}$$

Where:

$CO_{2T,x}$	=	Net annual mass of CO <sub>2</sub> measured by flow meter x (metric tons).
$Q_{x,p}$	=	Quarterly mass flow through meter x in quarter p (metric tons).
$C_{CO_2,p,x}$	=	Quarterly CO <sub>2</sub> concentration measurement in flow for flow meter x in quarter p (wt. percent CO <sub>2</sub> , expressed as a decimal fraction).
p	=	quarter of the year.
x	=	flow meter

For a volumetric flow meter, the total mass of CO<sub>2</sub> is calculated in metric tons by multiplying the metered volumetric flow at standard conditions by the CO<sub>2</sub> concentration in the flow, according to the formula below.



To apply the equation below, all measured volumes are converted to the following standard industry temperature and pressure conditions for use in the equation below: standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere.

### Equation B-2

$$CO_{2T,x} = \sum_{p=1}^4 (Q_{x,p}) x D x C_{CO_2,p,x}$$

Where:

$CO_{2T,x}$	=	Net annual mass of CO <sub>2</sub> measured by flow meter x (metric tons).
$Q_{x,p}$	=	Quarterly volumetric flow through meter x in quarter p at standard conditions (standard cubic meters).
D	=	Density of CO <sub>2</sub> at standard conditions (metric tons per standard cubic meter): 0.0018682.
$C_{CO_2,p,x}$	=	Quarterly CO <sub>2</sub> concentration measurement in flow for flow meter x in quarter p (vol. percent CO <sub>2</sub> , expressed as a decimal fraction).
p	=	quarter of the year.
x	=	flow meter.

When CO<sub>2</sub> is measured using more than one meter within the same component of the CCS project (e.g., multiple CO<sub>2</sub> injection wells), it may be necessary to sum the meter readings to calculate an aggregate mass of CO<sub>2</sub>, as shown in the following equation.

### Equation B-3

$$CO_2 = \sum_{x=1}^X CO_{2T,x}$$

Where:

$CO_2$	=	Total mass of CO <sub>2</sub> measured by all flow meters in year y (metric tons).
$CO_{2T,x}$	=	Total mass of CO <sub>2</sub> measured by flow meter x, as calculated in Equation A-1 or Equation A-2 in year y (metric tons).
X	=	Total number of flow meters.

### Additional Method for Calculating Emissions from Electricity Use

The following equation can be used to quantify GHG emissions from the use of grid electricity at any component 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).

#### Equation B-4

<b><math>PE_{Elec, y} = \sum (Electrical\ Rating_i \times Hours_i \times Load_i) \times EF_{Electricity}</math></b>		
Where,		
<b><math>PE_{S-P-Elec, y}</math></b>	=	Project emissions from electricity used to operate equipment at the CO <sub>2</sub> storage site in year y (tCO <sub>2e</sub> /yr).
<b>Electrical Rating<sub>i</sub></b>	=	Electrical rating in MW for each piece of equipment used to operate equipment associated with the relevant component (e.g., capture, transport or storage) of the CCS project (MW).
<b>Hours<sub>i</sub></b>	=	Operating hours for each piece of equipment (hours). Estimated or assumed to be 8760 hours for conservativeness.
<b>Load<sub>i</sub></b>	=	% Loading of each piece of equipment (unitless). Estimated or assumed to be 100%.
<b><math>EF_{Electricity}</math></b>	=	Emission factor for electricity generation in the relevant region, by (in order of preference) PCA, eGRID subregion, or State (tCO <sub>2e</sub> /MWh).-See Section 4.2.1 for estimation procedures.

### Additional Method for Calculating Stationary Combustion Emissions from the Primary Process Based on Fuel Use

The following equation can be used to quantify GHG emissions from stationary combustion from the primary process at the capture site. It can be used for projects where directly measuring the volume (or mass) of CO<sub>2</sub> produced at the primary process is not possible.

## Equation B-5

$$\text{CO}_2 \text{ Produced}_{\text{PP}, y} = \sum (\text{Fuel}_i \times \text{Mass Frac}_{\text{Carbon}, i} \times 44/12)$$

Where,

**CO<sub>2</sub> Produced<sub>PP, y</sub>** = Gross amount of CO<sub>2</sub> produced from the primary process in each year (tCO<sub>2</sub>/yr).

**Fuel<sub>i</sub>** = Total volume or mass of fuel, by fuel type i, input into the primary process in year each (e.g., m<sup>3</sup> or kg).

**Mass Frac<sub>Carbon, i</sub>** = Average mass fraction of carbon in fuel type i, (fraction, expressed as a decimal).

**44/12** = Conversion factor to convert from mass of carbon to mass of carbon dioxide using molecular weights (unitless).

## Additional Method for Calculating Stationary Combustion Emissions from Flaring

The following equation can be used to quantify GHG emissions from stationary combustion at the storage site in situations where a flare is used to combust gases produced from the formation (e.g., gases that may contain CO<sub>2</sub> that originate from the capture site).

## Equation B-6

$$\text{PE}_{\text{Flaring}, y} = \sum (\text{Gas Flared}_i \times \sum (\text{C}_i \times \text{y}_i) \times 44.01/23.64) + \sum (\text{Flare Fuel}_i \times \text{EF}_{\text{CO}_2 \text{ Flare Fuel } i}) + \sum [\text{Gas Flared}_i \times (1 - \text{DE}) \times \% \text{CH}_4 \times \rho_{\text{CH}_4}] \times \text{CH}_4\text{-GWP} + \sum [\text{Flare Fuel}_i \times \% \text{CH}_4 \times \rho_{\text{CH}_4} \times (1 - \text{DE})] \times \text{CH}_4\text{-GWP} + \sum (\text{Vol.}_{\text{Gas Flared } i} \times \text{EF}_{\text{N}_2\text{O}_{\text{Gas Flared } i}}) + (\text{Flare Fuel}_i \times \text{EF}_{\text{N}_2\text{O}_{\text{Flare Fuel } i}}) \times \text{N}_2\text{O-GWP}$$

Where,

**PE<sub>Flaring, y</sub>** = Project emissions from flaring of gases at hydrocarbon production facilities in year y (tCO<sub>2e</sub>/yr). Only applicable to facilities that flare gases that may contain CO<sub>2</sub> originating from the producing formation.

**Gas Flared<sub>i</sub>** = Volume of gas flared at hydrocarbon production facilities at the storage site in year y (m<sup>3</sup>/year).

**Flare Fuel<sub>i</sub>** = Volume of each supplemental fuel, by fuel type i, used to ensure complete combustion of gases from the producing formation in year y (m<sup>3</sup>/year).

**C<sub>i</sub>** = Number of carbon atoms would be assessed based on the chemical formula of each gas (e.g., 1 for CH<sub>4</sub>, 1 for CO<sub>2</sub>, 2 for C<sub>2</sub>H<sub>6</sub>)

**y<sub>i</sub>** = Direct measurement of the mole fractions of each carbon-containing gas in the gas mixture.

<b>44.01</b>	=	Reference value for Molecular Weight of CO <sub>2</sub> (grams per mole).
<b>23.64</b>	=	Volume occupied by 1 mole of an ideal gas at standard conditions of 15°C and 1 atmosphere.
<b>DE</b>	=	Destruction efficiency of the flare (unitless).
<b>%CH<sub>4</sub></b>	=	Concentration of CH <sub>4</sub> in the gas stream that is being flared in year y (volume percent CO <sub>2</sub> or CH <sub>4</sub> , expressed as a decimal fraction).
<b>ρ CH<sub>4</sub></b>	=	Density of CO <sub>2</sub> at standard conditions = 0.00190 metric ton/ m <sup>3</sup> .
<b>EF N<sub>2</sub>O<sub>Gas Flared i</sub></b>	=	N <sub>2</sub> O emission factor for flaring of gas stream originating from the producing formation (e.g., tN <sub>2</sub> O/m <sup>3</sup> ).
<b>EF CO<sub>2</sub> Flare Fuel i</b>	=	CO <sub>2</sub> emission factor for combustion of each supplemental fuel, by fuel type i, used to ensure complete combustion of gases from the producing formation (e.g., tCO <sub>2</sub> /m <sup>3</sup> ).
<b>EF N<sub>2</sub>O<sub>Flare Fuel i</sub></b>	=	N <sub>2</sub> O emission factor for combustion of each supplemental fuel, by fuel type i, used to ensure complete combustion of gases from the producing formation (e.g., tN <sub>2</sub> O/m <sup>3</sup> ).
<b>CH<sub>4</sub>-GWP</b>	=	Global Warming Potential of CH <sub>4</sub> .
<b>N<sub>2</sub>O-GWP</b>	=	Global Warming Potential of N <sub>2</sub> O.

### Additional Guidance on Selecting Emission Factors to Quantify Fugitive Emissions

The following table provides a summary of potential fugitive and venting emission sources and relevant US EPA emission factors that may be applicable to CO<sub>2</sub> injection and storage facilities as well as to hydrocarbon production facilities at the storage site in the producing formation.

**Table B-1** Surface Components as Potential Emissions Sources at Injection Facilities<sup>64</sup>

Emissions Source	Engineering Estimates	Direct Measurement	Equipment Count and Population Factor	Reference in EPA GHGRP 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
Centrifugal compressor wet seal oil degassing venting			X	Eq. W-22 to W-25
Other equipment leaks (valve, connector, open-ended line, pressure relief valve)			X	Eq. W-31

<sup>64</sup> US Environmental Protection Agency. Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, Final Rule: Subpart W. November 30, 2010.

## APPENDIX C - STANDARDS AND PROCEDURES FOR CLASS II WELLS IN TEXAS

The official rules of the Railroad Commission of Texas are found in the Texas Administrative Code (TAC) Title 16, Part 1, Chapters 1-20.<sup>65</sup> Chapter 3 includes rules of the Oil and Gas Division. Under Statewide Rules 9, 46, 95, 96, and 97, operators of injection and disposal wells associated with oil and gas exploration, production, transportation, or underground storage Class II wells must obtain a permit from the Railroad Commission. Thus, all Class II wells in Texas must be approved by the Commission before injection operations can legally begin. Pursuant to Rules 9, 46, 95, 96, and 97, and the applicable application forms, such permits will be approved only if the applicant satisfies the burden of showing that fresh water will be protected.

Once a permit is granted, the operator is bound by all applicable Commission rules and permit conditions by virtue of accepting the right to operate pursuant to the permit. It is necessary to examine permit conditions, as well as statewide rules, in order to determine what actions are necessary for compliance.

### Types of Permits

Permits to dispose of salt water or other oil and gas wastes by injection into porous formations that are **not** productive of oil, gas, or geothermal resources are issued under Statewide Rule 9. Form W-14 is used to apply for this type of permit.

Permits to inject water, steam, gas, oil and gas wastes, or other fluids into porous formations that are productive of oil, gas, or geothermal resources are issued under Statewide Rule 46. Forms H-1 and H-1A are used to apply for this type of permit.

Permits to conduct hydrocarbon storage operations are issued under Statewide Rules 95, 96, or 97. Form H-4 is used to apply for these types of permits.

### Commercial Disposal Wells

A commercial disposal well is a well whose owner or operator receives compensation from others for the disposal of oilfield fluids or other oil and gas wastes that are wholly or partially trucked to the well and the primary business purpose of the well is to provide these services for compensation. Permits for commercial disposal wells contain special conditions for surface facilities associated with waste management.

### Permitting Process

All permit applications for Class II wells come to the Technical Permitting Section, where they are evaluated and processed. If a hearing is requested or required, the Technical Permitting Section requests that a hearing be scheduled, and the Commission provides notice to all interested persons.

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<sup>65</sup> <http://www.rrc.state.tx.us/rules/rule.php>

After the hearing, the examiners recommend final action to the Commissioners, who decide if the permit will be issued. If no protests are received on an application, the Director of Technical Permitting may administratively approve the application.

See the section titled "Injection and Disposal Well Permitting" for more detail on permitting standards and procedures.

### **Transfer and Modification of Permit**

An injection or disposal well permit may be transferred only after notice to the Commission. Written notice of intent to transfer the permit must be submitted to the Commission on Form P-4 at least 15 days prior to the date the operators plan for the transfer to occur. Permit transfer will not occur until the Form P-4 has been approved by the Commission.

An injection or disposal well permit may be terminated, suspended, or modified for just cause, such as a substantial change in well completion or operation, pollution of fresh water, substantial violations of permit conditions or rules, misrepresentations by the applicant, or the escape of injected fluids from the authorized zone. Notice and opportunity for hearing are provided in the same manner as in the initial permit process.

### **Geological Requirements**

The authorized injection or disposal strata must be isolated from overlying usable quality water by a sufficient thickness of relatively impermeable strata, which is generally considered to be an accumulative total of at least 250 feet of clay or shale. Variances in the total thickness required are considered on the basis of continuity of strata, thickness of individual strata, or the presence of relatively impermeable strata other than clay or shale. No injection or disposal well will be permitted where faults, fractures, structure, or other geologic factors indicate that isolation of the authorized injection or disposal zone is jeopardized. The operator must submit adequate geological information to show compliance with this requirement.

### **Casing and Cementing**

Injection and disposal wells must be cased and cemented in accordance with Statewide Rule 13 to prevent the movement of fluids into sources of fresh water. Rule 13 requires that surface casing be set and cemented to protect fresh water strata, as defined by the Texas Commission on Environmental Quality (TCEQ), formerly the Texas Natural Resource Conservation Commission. Cement is required to be circulated to the surface by the pump and plug method, and the specifications for cement quality and casing integrity set out in the rule must be met.

Injection and disposal wells must also meet UIC criteria for adequacy of cement to confine injected fluids. These criteria are 100 feet of well bonded cement as determined by a bond log, 250 feet of cement as evidenced by a temperature survey, or 400 to 600 feet of cement as determined by a slurry yield calculation. The flexibility in calculated annular footage allows for consideration of the operating conditions, type of cement used, and characteristics of the formation.

Wells that are converted from producers to injection into the same productive formation usually meet UIC cementing requirements if they were completed in compliance with Rule 13.

### **Area of Review**

Statewide rules require that an applicant for an injection or disposal well permit examine the data of record for wells that penetrate the proposed injection zone within a one quarter (1/4) mile radius of the proposed well to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids into strata other than the authorized injection or disposal zone. A permit applicant must submit a map showing the location of all wells of public record within 1/4 mile as part of the permit application. For those wells that penetrate the top of the injection or disposal zone, the applicant must attach a tabulation of the wells showing the dates the wells were drilled and the present status of the wells. Alternatively, if the applicant can show, by computation, that a lesser area will be affected by pressure increases, then the lesser area may be used in lieu of the fixed radius. In addition, an applicant may seek a variance from the Area of Review requirements by demonstrating that no significant increase in risk of groundwater contamination will result from the variance. No permit will be issued where the information submitted indicates that fresh water resources will be endangered unless permit conditions require appropriate corrective action in the area (e.g. remedial cementing, re-plugging inadequately plugged area wells, or more frequent testing and monitoring).

### **Standard Equipment Requirements**

All newly drilled or converted injection wells permitted under Rule 46 and all disposal wells permitted under Rule 9 must be equipped with tubing set on a mechanical packer unless an exception is granted by the director for good cause. Pressure observation valves are required on the tubing and each annulus.

### **Operating Requirements**

Maximum injection pressure limitations have been part of the Commission's permitting program for many years and continue to be required as a condition of each injection or disposal well permit. Pressure limitations are established to provide adequate assurance that injection will not initiate fractures in the confining zones. The maximum surface injection pressure may not ordinarily exceed 1/2 psi per foot of depth to the top of the authorized injection or disposal interval. A fracture pressure step-rate test must be performed to justify a higher pressure.

### **Monitoring and Reporting**

The operator of each injection or disposal well is required by the statewide rules to monitor the injection pressure and volume on a monthly basis and to report the results annually on Form H-10. Any downhole problem that indicates the presence of leaks in the well must be reported to the appropriate district office within twenty-four (24) hours.

See the section titled "Injection and Disposal Well Monitoring" for more detail on monitoring requirements.

### **Mechanical Integrity**

All injection and disposal wells must be pressure tested before injection operations begin, after any workover that disturbs the seal between the tubing, packer, and casing, and at least once every five (5)



years to determine if leaks exist in the tubing, packer, or casing. Some permits require more frequent tests, such as annual pressure tests for converted wells with short surface casing. The appropriate district office must be notified before any pressure test to allow a Commission representative to witness the test. The operator must then file a record of the test with the district office (Form H-5) within 30 days of the test. As an alternative to the five-year pressure testing, the operator may monitor the casing-tubing annulus pressure and report the results annually if the reported information demonstrates mechanical integrity and provided that the well is pressure tested at least once every ten (10) years.

Wells not equipped with tubing and packer or with other non-standard completions may require special down hole surveys to demonstrate mechanical integrity. These surveys must be approved in advance for a specific wellbore by Technical Permitting in Austin unless they are expressly required by the injection/disposal well permit.

See the section titled "Injection and Disposal Well Mechanical Integrity Testing" for more detail on mechanical integrity testing requirements.

### **Completion Reports**

A completion report (Form W-2 or G-1) must be filed with the appropriate district office within thirty (30) days of completion or conversion to disposal or injection to reflect the new or current completion.

### **Exceptions**

The statewide rules allow the director to grant exceptions to tubing and packer, packer setting depth, and pressure observation valve requirements of the rules upon proof of good cause. In addition, the district office may grant an exception to the surface casing requirements of Statewide Rule 13 and authorize use of the multistage completion process. Multistage cementing (in lieu of setting surface casing) is not normally authorized as a means to protect fresh water strata for wells drilled expressly as injection or disposal wells.

### **Plugging and Abandonment**

All injection and disposal wells are required to be plugged upon abandonment, in accordance with Statewide Rule 14. A notice of intention to plug and abandon (Form W-3A) must be filed with the appropriate district office and received five (5) days prior to the beginning of plugging operations. Plugging operations may not begin prior to the date shown on the Form W-3A unless authorized by the District Director.

The general requirements of Rule 14 ensure the protection of all formations bearing fresh groundwater, oil, gas, or geothermal resources. Each well is also subject to the specific requirements of Rule 14 that are applicable to the particular well completion situation. Special plugging requirements that are specific to the well, field, or area may apply at the discretion of the District Director.

Within thirty (30) days after a well is plugged, a complete record (Form W-3) must be filed in duplicate with the appropriate district office.

## APPENDIX D - STATE LEGISLATIVE ACTIONS<sup>66</sup>

### SOUTHERN STATES ENERGY BOARD *Carbon Capture and Sequestration Legislation* *In the United States of America*

#### Introduction

At the time of publication, there were 23 states with Carbon Capture and Storage (CCS) related legislation, which are: AZ, MI, NY, PA, CA, IL, KY, MN, OK, VA, CO, FL, IN, KS, LA, MS, MT, ND, NM, TX, WA, WV and WY.

Four states had CCS Bills Pending as of 2011, which are: AZ, MI, NY and PA.

While coal power is associated mainly with the Midwest and Appalachian regions, the states with CCS legislation represent a comprehensive cross section of the country. States differ on their approach to enforcing these bills. Some states, such as Texas, are pushing full steam ahead, yet others, like Montana, awaited an EPA final rule. Some tackle the statute first and regulations second (Wyoming, North Dakota), while others are working to create legislative recommendations (Utah, Illinois, West Virginia). Kansas, among others, has concluded that existing legislative authority is sufficient and is able to move directly to promulgation of final regulations.

This study on state CCS legislation does not include every element addressed by these bills. Instead, it is intended to give an overview of four key areas identified as necessary elements of a broader comprehensive regulatory framework governing CCS activities. The key areas are Project Authority, Pore Space and Carbon Dioxide (CO<sub>2</sub>) Ownership, Liability and Financing Sources.

**Project Authority:** This area addresses which state regulatory agency (SRA) will be charged with developing and administering rules and regulations governing CCS projects. The agency must have the authority to require compulsory joining of all participating interests in the underground storage reservoir and have appropriate permitting authority to require and operator to submit any data necessary to evaluate a proposed CO<sub>2</sub> storage project. Examples of such SRAs are state oil and gas regulatory agencies, state environmental agencies or state public utility commissions.

**Pore Space and CO<sub>2</sub> Ownership:** This area addresses who has the property rights to inject CO<sub>2</sub> into wells and who owns the CO<sub>2</sub> in case of unintended trespass. The right to use reservoirs and associated pore space is considered a private property right in the United States and must be acquired from the owner of those rights. To determine this, states are most likely to follow their traditional common law approach in determining these rights and, in most cases, pore space is deemed to be owned by the surface estate. CO<sub>2</sub>, on the other hand, is treated like any other commodity and, in general, is owned by the injector.

**Liability:** This area addresses what party is liable for the injected CO<sub>2</sub> both during the injection, the closure and the long-term, post closure phase. What party is liable depends, therefore, on the phase of the project. The injection phase is the period of time during active injection. The closure period is the time when the plugging of the well is completed and continues until a future date is reached, usually 10 years after injection activities and the wells are plugged. During these phases, the operator is the liable party. The post closure phase is the period of time beginning when the project is deemed complete, usually marked by the issuance of a Certificate of Completion, and extends for the life of the well. During this phase, liability transfer to the state for monitoring, verification and remediation activities. The injector is then usually released from all liability.

**Financing Sources:** This area addresses both the costs of the CO<sub>2</sub> injection projects themselves and the long-term costs. For the costs associated with the injection project, many states will give tax incentives in the form of sales tax, income tax or property tax exemptions for qualifying endeavors. Many states have established some type of CCS trust fund to pay for the expense of long-term monitoring, verification and remediation. These trusts tend to be state administered and industry funded on a cost per ton basis.

<sup>66</sup> July 2011 - Southeast Regional Carbon Sequestration Partnership and Southern States Energy Board

State	Bill (year)	Project Authority	Pore Space/CO <sub>2</sub> Ownership	Liability	Financing Source
AZ	SCR 1033 (2011) Pending	Arizona Department of Environmental Quality (ADEQ)			ADEQ is urged to allow the use of commercially available technologies that are designed to be as efficient as is economically practicable, including advanced super-critical pulverized coal, ultra super-critical pulverized coal, and that are designed to be carbon capture and sequestration-compatible, as potential best available control technology.
CA	SB 669 (2011) Pending	State Energy Resources Conservation and Development Commission			Provides for the full recovery in rates of long-term commitments entered into through a contract approved by the commission for electricity generated by zero- or low-carbon generating resources demonstrating new technology, if the commission determines that the commitment would benefit the state's ratepayers, economy, and the environment.
CA	A 1504 (2010) Enacted	Board of Forestry and Fire Protection			Permits fees collected under the Global Warming Solutions Act of 2006 to be used for related studies and analyses.
CO	HJR 1028 (2010) Enacted	U.S. Congress			Urges the United States Congress to pass comprehensive legislation that promotes clean energy jobs and addresses the effects of climate change including CCS technology.
CO	HB 06-1281 (2006) Enacted				Creates a CCS program and provides incentives for IGCC plants.
FL	HB 549 (2007) Enacted Ch. No. 2007-117				Provides incentives for IGCC plants.
IL	SB 1567 (2011) Pending	Carbon Capture and Sequestration Legislation Commission	To be determined by the Commission.	To be determined by the Commission.	
IL	SB 1821 (2011) Enrolled	Illinois Commerce Commission	Pipeline owners	Pipeline owners	Funding is provided by CO <sub>2</sub> pipeline owners.
IL	SB 678 (2010) Enacted P.A. 96-1491	FutureGen Alliance	Title transfers once injected.	FutureGen has limited liability which only arises out of or resulting from the storage, escape, release, or migration of the post-injection sequestered CO <sub>2</sub> .	State aided in securing \$1billion for FutureGen.
IL	SB 3686 (2010) Sine Die	Illinois Power Agency	"Initial Clean Coal Facility" or the Illinois Power Agency if requested.	Utility and alternative electric suppliers will have limited liability while in commercial operation.	Requires offsetting of excess emissions.
IL	P.A. 92-0012 (2002) P.A. 93-0167 (2004) P.A. 94-65 (2005) P.A. 94-1030 (2006) P.A. 95-18 (2007)				Incentives for IGCC plants.
IL	SB 1987 (2008) Enacted P.A. 95-1027				Illinois power agency may fund or operate sequestration facility.
IL	SB 1592 (2007) Enacted P.A. 95-0481				Incentives for advanced coal plants in locations where geology is suitable for sequestration.
IL	SB 1704 (2007) Enacted P.A. 95-0018		Illinois to take title to injected carbon dioxide from the FutureGen project.	State assumes any liabilities associated with the sequestered gas both during operation and for long-term liability, as well as any current or future environmental benefits, marketing claims, tradable credits, emissions allocations or offsets.	Exempts the FutureGen project from Illinois tax on electrical generating units.

State	Bill (year)	Project Authority	Pore Space/CO <sub>2</sub> Ownership	Liability	Financing Source
IN	P.L. 105-1989 (1989) P.L. 159-2002 (2002) P.L. 174-2005 (2005) P.L. 191-2005 (2005) P.L. 175-2007 (2007)				Incentives for clean coal technology.
KS	HB 2418 (2010) Enacted Ch. No. 2010-63	State Corporation Commission		Exempts the Commission and the state from assuming liability for the underground storage of carbon dioxide or the maintenance of any carbon dioxide injection well or underground storage of carbon dioxide except as permitted by the Kansas tort claims act.	Fees may be collected by the commission and put into the "carbon dioxide injection well and underground storage fund."
KS	HB 2419 (2007) Enacted	State Corporation Commission			Property and income tax incentives for CCS.
KS	SB 303 (2006) Enacted				Incentives for IGCC, such as tax credits and an amortization deduction in an amount equal to 55% of the amortizable costs of such new qualifying pipeline for the first taxable year in which such new qualifying pipeline is in production, and 5% of the amortizable costs of such new qualifying pipeline for each of the next nine taxable years.
KY	SB 50 (2011) Enacted KRS 154.27	Pipeline Company	Grants companies constructing carbon dioxide transmission pipelines eminent domain powers.		
KY	HB 259 (2011) Enacted KRS 353.1-7	Energy and Environment Cabinet		Liability for stored carbon dioxide will pass to the federal or state government.	
KY	HB 1 (2007) Pending				Tax incentives for advanced coal plants.
LA	HB 495 (2010) Enacted Act 193, R.S. 9:1103		Monetary compensation is provided to the owner unless given by a contract or related to Coastal Protection and Restoration Authority.		
LA	HB 733 (2010) Enacted Act 527, R.S. 3:1221	Office of Soil and Water Conservation			Office is to participate in CCS programs.
LA	HB 661 (2009) Enacted Act 517	Office of Conservation	CO <sub>2</sub> ownership matter of private contract.	Operator is liable during operation; state assumes ownership 10 years after injection is complete; operators and others with interest are released from future liability.	
LA	HB 1117 (2008) Enacted Act 315	State Mineral Board	CO <sub>2</sub> owned by operator.		
LA	HB 1220 (2008) Enacted Act 315			State Mineral Board may operate and assume responsibility for facilities.	
MI	HB 4399 (2011) Pending	Department of Environmental Quality	Owner(s) having a property interest.		Fees will be put into the "Mineral Well Regulatory Fund."
MI	HB 4401 (2011) Pending	Department of Environmental Quality	Owner(s) having a property interest.	Project owner is immune from civil liability.	CCS project funded by the Owner and must be approved by the Department.

State	Bill (year)	Project Authority	Pore Space/CO <sub>2</sub> Ownership	Liability	Financing Source
MI	HB 6522 (2010) Pending	State Tax Commission	CCS equipment is seen as industrial property.		
MI	HB 4016 (2009) Pending	Department of Environmental Quality			Provides a business tax credit for certain costs incurred during carbon dioxide sequestration and capture.
MI	Draft Bill	Department of Environmental Quality	Pore space owned by surface owner.	Operator is liable during operation; state assumes liability upon issuance of Certificate of Completion.	Carbon Dioxide Storage Facility Trust Fund
MI	SB 775 (2009) Pending	Department of Environmental Quality	CO <sub>2</sub> ownership begins with operator and transfers to state 10 years after Notice of Completion.	Operator is liable during operation; state assumes liability 10 years after Notice of Completion.	Carbon Dioxide Storage Facility Trust Fund
MN	HB 1669 (2011) Pending	The State of Minnesota			The state is reserving credits for CCS in current or future state lands.
MN	SF 145 (2007) Enacted Ch. 136				Incentives for IGCC.
MS	SB 2723 (2011) Enacted 53-11-1	State Oil and Gas Board	At least a majority interest in the property rights is required. Sequestration wells, buildings and equipment utilized in geologic sequestration are owned by the storage operator, which includes pipelines. The owner of the carbon dioxide shall have no right to gas, liquid hydrocarbons, salt, or other commercial minerals.	To the Owner(s)	Carbon Dioxide Storage Fund
MS	HB 1459 (2009) Enacted 27-65-19				Income tax of 1.5% on businesses that sell CO <sub>2</sub> for EOR or sequestration.
MT	SB 285 (2011) Enacted 82-11-183	Board of Oil and Gas Conservation in consultation with the Department of Environmental Quality and the Department of Natural Resources and Conservation	The geologic storage operator has title to the geologic storage reservoir and may transfer title of the reservoir and the stored carbon dioxide to the state.	If the title is not transferred to the state, then the Operator accepts liability.	
MT	SB 498 (2009) Enacted	Board of Oil and Gas Conservatory with comments from Department of Environmental Quality	Pore space owned by surface owner. CO <sub>2</sub> owned by operator.	Operator is liable during operation; state assumes long term liability.	
MT	HB 3 (2007) Enacted				Tax incentives for gasification plants that sequester CO <sub>2</sub> .
ND	SB 2318 (2011) Enacted	Legislative Management			Legislative Management will look to the possibility of CO <sub>2</sub> storage easements.
ND	SB 2034 (2009) Enacted 57-51.1-03				Tax incentives for Enhanced Oil Recovery (EOR) with CO <sub>2</sub> .
ND	SB 2095 (2009) Enacted 38-22 Repealed 38-08-24	Industrial Commission	CO <sub>2</sub> owned by operator.	Operator is liable during operation; state assumes long term liability.	
ND	SB 2139 (2009) Enacted		Pore space owned by surface owner; severance prohibited.		
ND	SB 2221 (2009) Enacted 57-60-01; 57-60-02.1 Amended 57-60-03				Tax incentives for coal plants that capture CO <sub>2</sub> .
NM	SB 994 (2007) Enacted Ch.229				Incentives for energy facilities to capture and sequester CO <sub>2</sub> .



State	Bill (year)	Project Authority	Pore Space/CO <sub>2</sub> Ownership	Liability	Financing Source
NY	A03182 (2010) Pending	Administered by the Department of Environmental Conservation (DEC)	The operator has ownership of the CO <sub>2</sub> and the landowners have ownership of the pore space.	Default liability is to the Operator unless contracted to the owner.	Relates to a pilot program to enable the capture and storage of carbon dioxide and establishes the carbon capture and sequestration act. This bill would have no significant fiscal impacts on the state.
NY	A05836 (2010) Pending	NY Department of Environmental Conservation	Pore space owned by surface estate owner.	Operator is liable during operation; state assumes long term liability after 10 years.	
NY	A08802 (2010) Pending	NY Department of Environmental Conservation	Pore space owned by surface owner. CO <sub>2</sub> owned by operator.		
NY	Advanced Clean Coal Power Plant Initiative (2006)				Incentive program for advanced coal plants with sequestration.
OK	SB 2024 (2010) Pending	Corporation Commission			
OK	SB 610 (2009) Enacted	Corporation Commission for fossil fuel bearing formations; Department of Environmental Quality for all others	CO <sub>2</sub> owned by operator. Does not alter the incidents of ownership, or other rights, of the owners of the mineral estate or adversely affect enhanced oil or gas recovery efforts in the state. Prohibits the use of eminent domain to be used by a private operator.		The Petroleum Storage Tank Release Environmental Cleanup Indemnity Fund and Program and the Leaking Underground Storage Tank Trust Fund. State water/wastewater loans and grants, revolving fund, and other related financial aid programs including federal funding.
PA	HB 2405 (2010) Pending	Pennsylvania Public Utility Commission	CCS facility owns the CO <sub>2</sub> once transferred. State will allow the lease of state lands for CO <sub>2</sub> pipelines.	CCS facilities receive liability of CO <sub>2</sub> , once transferred, and the coal combustion plant will become immune. Operators of CCS facilities have the same rights and subject to the same penalties as the Solid waste Management Act, but Administrative penalties cannot exceed \$50,000. Upon Closure of a CCS facility, liability is transferred to the state.	Carbon Dioxide Indemnification Fund
TX	HB 1796 (2009)  Enacted Ch. 382	General Land Office and the Bureau of Economic Geology to build and operate a carbon dioxide repository on state-owned, offshore, submerged land.	CO <sub>2</sub> owned by state for offshore sequestration.	School Land Board is liable during operation for offshore sequestration, but liability is not relieved from a producer of CO <sub>2</sub> prior to it being stored.	Permanent School Fund, state grants
TX	SB 1387 (2009)  Enacted Section 27.002	Railroad Commission has jurisdiction over the injection of CO <sub>2</sub> into wells for production of oil or gas.	CO <sub>2</sub> owned by operator, unless otherwise agreed.		Anthropogenic Carbon Dioxide Storage Trust Fund
TX	HB 469 (2009)  Enacted Ch. 490	Comptroller			Tax incentive for energy projects that capture and sequester CO <sub>2</sub>
TX	HB 3732 (2007)  Enacted Ch. 447	State Energy Conservation Office			Incentives for advanced energy projects, including advanced coal, such as "The advanced clean energy project grant and loan program."

State	Bill (year)	Project Authority	Pore Space/CO <sub>2</sub> Ownership	Liability	Financing Source
VA	SB 247 (2010) pending	Department of Mines, Minerals and Energy	CO <sub>2</sub> owned by operator, transfer to Commonwealth upon issuance of Certificate of Project Completeness.	Operator liable during operation. Transfers to Commonwealth upon issuance of Certificate of Project Completeness.	Carbon Dioxide Storage Facility Trust Fund
VA	SB 1416/HB 3068 (2007)  Enacted Ch. 933	State Corporation Commission (SCC)			Incentives for advanced coal plants
WA	SB 6001 (2007)  Partially Vetoed Ch. 307	Department of Ecology			
WV	HB 2860/SB 396 (2009)  Enacted Ch. 97	Department of Environmental Protection	Will be determined by recommendations from the CCS working group	Civil liability exists for any loss of fish or any other aquatic life.	
WY	HB 17 (2010)  Enacted Ch. 52	Water Quality Division of the Department of Environmental Quality		Requires liability insurance policies for geologic sequestration site permittees.	Wyoming geologic sequestration special revenue account, funded by monies collected from entities permitted to operate geologic sequestration sites in Wyoming. Appropriates \$200,000 to fund the reclassification of a position within DEQ to help with the rule making and financial assurance duties imposed by this legislation
WY	HB 58 (2009)  Enacted Ch. 50		CO <sub>2</sub> owned by operator.	Operator liable during operation. No person is liable for the consequences of injecting carbon dioxide simply because they own the pore space, have the ability to control the pore space or have given consent to the injection.	
WY	SB 1 (2008)  Enacted Ch. 48				Funding for sequestration site evaluation and advancement of clean coal and carbon management activities (\$1.2 million)
WY	HB 90 (2008)  Enacted Ch. 30	Department of Environmental Quality			\$250,000 given to the working group for related expenses such as permitting.
WY	HB 89 (2008)  Enacted Ch. 29		Owner of the surface estate owns the pore space in all strata below the surface. Pore space owned by surface owner, may be severed.	Legal requirements for notice to real property owners are not required for pore space owners unless the law specifically identifies those owners as being required to be notified.	

The appropriate citation is American Carbon Registry (2015), *Methodology for Greenhouse Gas Emission Reductions from Carbon Capture and Storage Projects*, Version 1.0. Winrock International, Little Rock, Arkansas.