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U.S. EPA Final Rule on Mandatory Reporting of Greenhouse Gases
incorporated by reference in California's Regulation for the
Mandatory Reporting of Greenhouse Gas Emissions*

Unofficial Electronic Compilation

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ARB's Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations (CCR), sections 95100-95157) incorporated by reference certain requirements promulgated by the United States Environmental Protection Agency (U.S. EPA) in its Final Rule on Mandatory Reporting of Greenhouse Gases (Title 40, Code of Federal Regulations (CFR), Part 98). Specifically, section 95100(c) of ARB's regulation incorporated those requirements promulgated by U.S. EPA as published in the Federal Register on October 30, 2009, July 12, 2010, September 22, 2010, October 28, 2010, November 30, 2010, December 17, 2010, April 25, 2011, and November 29, 2013.

This compilation combines the various incorporated Federal Register versions into one document for the reader's convenience; however, this compilation is not an official edition of either the CFR or the CCR. While reasonable steps have been taken to make this unofficial compilation accurate, the officially published requirements, found within the incorporated Federal Register notices with the dates listed above, take precedence if there are any discrepancies.

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The official legal versions of the incorporated CFR provisions from the Federal Register are available, with the incorporated Federal Register notice and date, at <https://www.epa.gov/ghgreporting/resources-subpart-ghg-reporting>.

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**40 CFR Part 98
Subpart RR**

Mandatory Reporting of Greenhouse Gases

PART 98—MANDATORY GREENHOUSE GAS REPORTING

Subpart RR—Geologic Sequestration of Carbon Dioxide

§ 98.440	<u>Definition of the source category.</u>
§ 98.441	<u>Reporting threshold.</u>
§ 98.442	<u>GHGs to report.</u>
§ 98.443	<u>Calculating CO₂ geologic sequestration.</u>
§ 98.444	<u>Monitoring and QA/QC requirements.</u>
§ 98.445	<u>Procedures for estimating missing data.</u>
§ 98.446	<u>Data reporting requirements.</u>
§ 98.447	<u>Records that must be retained.</u>
§ 98.448	<u>Geologic sequestration monitoring, reporting, and verification (MRV) plan.</u>
§ 98.449	<u>Definitions.</u>

§ 98.440 Definition of the source category.

- (a) The geologic sequestration of carbon dioxide (CO₂) source category comprises any well or group of wells that inject a CO₂ stream for long-term containment in subsurface geologic formations.
- (b) This source category includes all wells permitted as Class VI under the Underground Injection Control program.
- (c) This source category does not include a well or group of wells where a CO₂ stream is being injected in subsurface geologic formations to enhance the recovery of oil or natural gas unless one of the following applies:
- (1) The owner or operator injects the CO₂ stream for long-term containment in subsurface geologic formations and has chosen to submit a proposed monitoring, reporting, and verification (MRV) plan to EPA and received an approved plan from EPA.
 - (2) The well is permitted as Class VI under the Underground Injection Control program.
- (d) **Exemption for research and development projects.** Research and development projects shall receive an exemption from reporting under this subpart for the duration of the research and development activity.
- (1) **Process for obtaining an exemption.** If you are a research and development project, you must submit the information in paragraph (d)(2) of this section to EPA by the time you would be otherwise required to submit an MRV plan under § 98.448. EPA will use this information to verify that the project is a research and development project.
 - (2) **Content of submission.** A submission in support of an exemption as a research and development project must contain the following information:

- (i) The planned duration of CO₂ injection for the project.
- (ii) The planned annual CO₂ injection volumes during this time period.
- (iii) The research purposes of the project.
- (iv) The source and type of funding for the project.
- (v) The class and duration of Underground Injection Control permit or, for an offshore facility not subject to the Safe Drinking Water Act, a description of the legal instrument authorizing geologic sequestration.

(3) *Determination by the Administrator.*

- (i) The Administrator shall determine if a project meets the definition of research and development project within 60 days of receipt of the submission of a request for exemption. In making this determination, the Administrator shall take into account any information you submit demonstrating that the planned duration of CO₂ injection for the project and the planned annual CO₂ injection volumes during the duration of the project are consistent with the purpose of the research and development project.
- (ii) Any appeal of the Administrator's determination is subject to the provisions of [part 78 of this chapter](#).
- (iii) A project that the Administrator determines is not eligible for an exemption as a research and development project must submit a proposed MRV plan to EPA within 180 days of the Administrator's determination. You may request one extension of up to an additional 180 days in which to submit the proposed MRV plan.

§ 98.441 Reporting threshold.

(a) You must report under this subpart if any well or group of wells within your facility injects any amount of CO₂ for long-term containment in subsurface geologic formations. There is no threshold.

(b) ***Request for discontinuation of reporting.*** The requirements of § 98.2(i) do not apply to this subpart. Once a well or group of wells is subject to the requirements of this subpart, the owner or operator must continue for each year thereafter to comply with all requirements of this subpart, including the requirement to submit annual reports, until the Administrator has issued a final decision on an owner or operator's request to discontinue reporting.

(1) ***Timing of request.*** The owner or operator of a facility may submit a request to discontinue reporting any time after the well or group of wells is plugged and abandoned in accordance with applicable requirements.

(2) ***Content of request.*** A request for discontinuation of reporting must contain either paragraph (b)(2)(i) or (b)(2)(ii) of this section.

(i) For wells permitted as Class VI under the Underground Injection Control program, a copy of the applicable Underground Injection Control program Director's authorization of site closure.

(ii) For all other wells, and as an alternative for wells permitted as Class VI under the Underground Injection Control program, a demonstration that current monitoring and

model(s) show that the injected CO₂ stream is not expected to migrate in the future in a manner likely to result in surface leakage.

(3) **Notification.** The Administrator will issue a final decision on the request to discontinue reporting within a reasonable time. Any appeal of the Administrator's final decision is subject to the provisions of [part 78 of this chapter](#).

§ 98.442 GHGs to report.

You must report:

- (a) Mass of CO₂ received.
- (b) Mass of CO₂ injected into the subsurface.
- (c) Mass of CO₂ produced.
- (d) Mass of CO₂ emitted by surface leakage.
- (e) Mass of CO₂ emissions from equipment leaks and vented emissions of CO₂ from surface equipment located between the injection flow meter and the injection wellhead.
- (f) Mass of CO₂ emissions from equipment leaks and vented emissions of CO₂ from surface equipment located between the production flow meter and the production wellhead.
- (g) Mass of CO₂ sequestered in subsurface geologic formations.
- (h) Cumulative mass of CO₂ reported as sequestered in subsurface geologic formations in all years since the facility became subject to reporting requirements under this subpart.

§ 98.443 Calculating CO₂ geologic sequestration.

You must calculate the mass of CO₂ received using CO₂ received equations (Equations RR-1 to RR-3 of this section), unless you follow the procedures in § 98.444(a)(4). You must calculate CO₂ sequestered using injection equations (Equations RR-4 to RR-6 of this section), production/recycling equations (Equations RR-7 to RR-9 of this section), surface leakage equations (Equation RR-10 of this section), and sequestration equations (Equations RR-11 and RR-12 of this section). For your first year of reporting, you must calculate CO₂ sequestered starting from the date set forth in your approved MRV plan.

(a) You must calculate and report the annual mass of CO₂ received by pipeline using the procedures in paragraphs (a)(1) or (a)(2) of this section and the procedures in paragraph (a)(3) of this section, if applicable.

- (1) For a mass flow meter, you must calculate the total annual mass of CO₂ in a CO₂ stream received in metric tons by multiplying the mass flow by the CO₂ concentration in the flow, according to Equation RR-1 of this section. You must collect these data quarterly. Mass flow and concentration data measurements must be made in accordance with § 98.444.

$$CO_{2T,r} = \sum_{p=1}^4 (Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}} \quad (\text{Eq. RR-1})$$

Where:

- $CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).
- $Q_{r,p}$ = Quarterly mass flow through a receiving flow meter r in quarter p (metric tons).
- $S_{r,p}$ = Quarterly mass flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (metric tons).
- $C_{CO_2,p,r}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (wt. percent CO_2 , expressed as a decimal fraction).
- p = Quarter of the year.
- r = Receiving flow meter.

(2) For a volumetric flow meter, you must calculate the total annual mass of CO_2 in a CO_2 stream received in metric tons by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Equation RR-2 of this section. You must collect these data quarterly. Volumetric flow and concentration data measurements must be made in accordance with § 98.444.

$$CO_{2T,r} = \sum_{p=1}^4 (Q_{r,p} - S_{r,p}) * D * C_{CO_2,p,r} \quad (\text{Eq. RR-2})$$

Where:

- $CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).
- $Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).
- $S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (standard cubic meters).
- D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.
- $C_{CO_2,p,r}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO_2 , expressed as a decimal fraction).
- p = Quarter of the year.
- r = Receiving flow meter.

(3) If you receive CO_2 through more than one flow meter, you must sum the mass of all CO_2 received in accordance with the procedure specified in Equation RR-3 of this section.

$$CO_2 = \sum_{r=1}^R CO_{2T,r} \quad (\text{Eq. RR-3})$$

Where:

- CO_2 = Total net annual mass of CO_2 received (metric tons).
- $CO_{2T,r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-1 or RR-2 for flow meter r.
- r = Receiving flow meter.

(b) You must calculate and report the annual mass of CO_2 received in containers using the procedures in paragraphs (b)(1) or (b)(2) of this section.

(1) If you are measuring the mass of contents in a container under the provisions of § 98.444(a)(2)(i), you must calculate the CO_2 received for injection in containers using Equation RR-1 of this section.

Where:

- $CO_{2T,r}$ = Net annual mass of CO_2 received in containers r (metric tons).
- $C_{CO_2,p,r}$ = Quarterly CO_2 concentration measurement of contents in containers r in quarter p (wt. percent CO_2 , expressed as a decimal fraction).
- $Q_{r,p}$ = Quarterly mass of contents in containers r in quarter p (metric tons).
- $S_{r,p}$ = Quarterly volume of contents in containers r redelivered to another facility without being injected into your well in quarter p (standard cubic meters).
- p = Quarter of the year.
- r = Containers.

(2) If you are measuring the volume of contents in a container under the provisions of § 98.444(a)(2)(ii), you must calculate the CO_2 received for injection in containers using Equation RR-2 of this section.

Where:

- $CO_{2T,r}$ = Net annual mass of CO_2 received in containers r (metric tons).
- $C_{CO_2,p,r}$ = Quarterly CO_2 concentration measurement of contents in containers r in quarter p (vol. percent CO_2 , expressed as a decimal fraction).
- $Q_{r,p}$ = Quarterly volume of contents in containers r in quarter p (standard cubic meters).
- $S_{r,p}$ = Quarterly mass of contents in containers r redelivered to another facility without being injected into your well in quarter p (metric tons).
- D = Density of the CO_2 received in containers at standard conditions (metric tons per standard cubic meter): 0.0018682.
- p = Quarter of the year.
- r = Containers.

(c) You must report the annual mass of CO_2 injected in accordance with the procedures specified in paragraphs (c)(1) through (c)(3) of this section.

(1) If you use a mass flow meter to measure the flow of an injected CO₂ stream, you must calculate annually the total mass of CO₂ (in metric tons) in the CO₂ stream injected each year in metric tons by multiplying the mass flow by the CO₂ concentration in the flow, according to Equation RR-4 of this section. Mass flow and concentration data measurements must be made in accordance with § 98.444.

$$CO_{2,u} = \sum_{p=1}^4 Q_{p,u} * C_{CO_{2,p,u}} \quad (\text{Eq. RR-4})$$

Where:

- CO_{2,u} = Annual CO₂ mass injected (metric tons) as measured by flow meter u.
- Q_{p,u} = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).
- C_{CO₂,p,u} = Quarterly CO₂ concentration measurement in flow for flow meter u in quarter p (wt. percent CO₂, expressed as a decimal fraction).
- p = Quarter of the year.
- u = Flow meter.

(2) If you use a volumetric flow meter to measure the flow of an injected CO₂ stream, you must calculate annually the total mass of CO₂ (in metric tons) in the CO₂ stream injected each year in metric tons by multiplying the volumetric flow at standard conditions by the CO₂ concentration in the flow and the density of CO₂ at standard conditions, according to Equation RR-5 of this section. Volumetric flow and concentration data measurements must be made in accordance with § 98.444.

$$CO_{2,u} = \sum_{p=1}^4 Q_{p,u} * D * C_{CO_{2,p,u}} \quad (\text{Eq. RR-5})$$

Where:

- CO_{2,u} = Annual CO₂ mass injected (metric tons) as measured by flow meter u.
- Q_{p,u} = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).
- D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.
- C_{CO₂,p,u} = CO₂ concentration measurement in flow for flow meter u in quarter p (vol. percent CO₂, expressed as a decimal fraction).
- p = Quarter of the year.
- u = Flow meter.

(3) To aggregate injection data for all wells covered under this subpart, you must sum the mass of all CO₂ injected through all injection wells in accordance with the procedure specified in Equation RR-6 of this section.

$$CO_{2I} = \sum_{u=1}^U CO_{2,u} \quad (\text{Eq. RR-6})$$

Where:

CO_{2I} = Total annual CO_2 mass injected (metric tons) through all injection wells.

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u .

u = Flow meter.

(d) You must calculate the annual mass of CO_2 produced from oil or gas production wells or from other fluid wells for each separator that sends a stream of gas into a recycle or end use system in accordance with the procedures specified in paragraphs (d)(1) through (d)(3) of this section. You must account for any CO_2 that is produced and not processed through a separator. You must account only for wells that produce the CO_2 that was injected into the well or wells covered by this source category.

(1) For each gas-liquid separator for which flow is measured using a mass flow meter, you must calculate annually the total mass of CO_2 produced from an oil or other fluid stream in metric tons that is separated from the fluid by multiplying the mass gas flow by the CO_2 concentration in the gas flow, according to Equation RR-7 of this section. You must collect these data quarterly. Mass flow and concentration data measurements must be made in accordance with § 98.444.

$$CO_{2,w} = \sum_{p=1}^4 Q_{p,w} * C_{CO_{2,p,w}} \quad (\text{Eq. RR-7})$$

Where:

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w .

$Q_{p,w}$ = Quarterly gas mass flow rate measurement for separator w in quarter p (metric tons).

$C_{CO_{2,p,w}}$ = Quarterly CO_2 concentration measurement in flow for separator w in quarter p (wt. percent CO_2 , expressed as a decimal fraction).

p = Quarter of the year.

w = Separator.

(2) For each gas-liquid separator for which flow is measured using a volumetric flow meter, you must calculate annually the total mass of CO_2 produced from an oil or other fluid stream in metric tons that is separated from the fluid by multiplying the volumetric gas flow at standard conditions by the CO_2 concentration in the gas flow and the density of CO_2 at standard conditions, according to Equation RR-8 of this section. You must collect these data quarterly. Volumetric flow and concentration data measurements must be made in accordance with § 98.444.

$$CO_{2,w} = \sum_{p=1}^4 Q_{p,w} * D * C_{CO_{2,p,w}} \quad (\text{Eq. RR-8})$$

Where:

- $CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w.
- $Q_{p,w}$ = Volumetric gas flow rate measurement for separator w in quarter p at standard conditions (standard cubic meters).
- D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.
- $C_{CO_2,p,w}$ = CO_2 concentration measurement in flow for separator w in quarter p (vol. percent CO_2 , expressed as a decimal fraction).
- p = Quarter of the year.
- w = Separator.

(3) To aggregate production data, you must sum the mass of all of the CO_2 separated at each gas-liquid separator in accordance with the procedure specified in Equation RR-9 of this section. You must assume that the total CO_2 measured at the separator(s) represents a percentage of the total CO_2 produced. In order to account for the percentage of CO_2 produced that is estimated to remain with the produced oil or other fluid, you must multiply the quarterly mass of CO_2 measured at the separator(s) by a percentage estimated using a methodology in your approved MRV plan. If fluids containing CO_2 from injection wells covered under this source category are produced and not processed through a gas-liquid separator, the concentration of CO_2 in the produced fluids must be measured at a flow meter located prior to reinjection or reuse using methods in § 98.444(f)(1). The considerations you intend to use to calculate CO_2 from produced fluids for the mass balance equation must be described in your approved MRV plan in accordance with § 98.448(a)(5).

$$CO_{2P} = (1+X) * \sum_{w=1}^W CO_{2,w} \quad (\text{Eq. RR-9})$$

Where:

- CO_{2P} = Total annual CO_2 mass produced (metric tons) through all separators in the reporting year.
- $CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w in the reporting year.
- X = Entrained CO_2 in produced oil or other fluid divided by the CO_2 separated through all separators in the reporting year (weight percent CO_2 , expressed as a decimal fraction).
- w = Separator.

(e) You must report the annual mass of CO_2 that is emitted by surface leakage in accordance with your approved MRV plan. You must calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 of this section.

$$CO_{2E} = \sum_{x=1}^X CO_{2,x} \quad (\text{Eq. RR-10})$$

Where:

- CO_{2E} = Total annual CO₂ mass emitted by surface leakage (metric tons) in the reporting year.
- CO_{2,x} = Annual CO₂ mass emitted (metric tons) at leakage pathway x in the reporting year.
- x = Leakage pathway.

(f) You must report the annual mass of CO₂ that is sequestered in subsurface geologic formations in the reporting year in accordance with the procedures specified in paragraphs (f)(1) and (f)(2) of this section.

(1) If you are actively producing oil or natural gas or if you are producing any other fluids, you must calculate the annual mass of CO₂ that is sequestered in the underground subsurface formation in the reporting year in accordance with the procedure specified in Equation RR-11 of this section.

$$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP} \quad (\text{Eq. RR-11})$$

Where:

- CO₂ = Total annual CO₂ mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.
- CO_{2I} = Total annual CO₂ mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.
- CO_{2P} = Total annual CO₂ mass produced (metric tons) in the reporting year.
- CO_{2E} = Total annual CO₂ mass emitted (metric tons) by surface leakage in the reporting year.
- CO_{2FI} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of this part.
- CO_{2FP} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity, for which a calculation procedure is provided in subpart W of this part.

(2) If you are not actively producing oil or natural gas or any other fluids, you must calculate the annual mass of CO₂ that is sequestered in subsurface geologic formations in the reporting year in accordance with the procedures specified in Equation RR-12 of this section.

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \quad (\text{Eq. RR-12})$$

Where:

- CO₂ = Total annual CO₂ mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.
- CO_{2I} = Total annual CO₂ mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.
- CO_{2E} = Total annual CO₂ mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of this part.

§ 98.444 Monitoring and QA/QC requirements.

(a) CO₂ received.

(1) Except as provided in paragraph (a)(4) of this section, you must determine the quarterly flow rate of CO₂ received by pipeline by following the most appropriate of the following procedures:

(i) You may measure flow rate at the receiving custody transfer meter prior to any subsequent processing operations at the facility and collect the flow rate quarterly.

(ii) If you took ownership of the CO₂ in a commercial transaction, you may use the quarterly flow rate data from the sales contract if it is a one-time transaction or from invoices or manifests if it is an ongoing commercial transaction with discrete shipments.

(iii) If you inject CO₂ received from a production process unit that is part of your facility, you may use the quarterly CO₂ flow rate that was measured at the equivalent of a custody transfer meter following procedures provided in subpart PP of this part. To be the equivalent of a custody transfer meter, a meter must measure the flow of CO₂ being transported to an injection well to the same degree of accuracy as a meter used for commercial transactions.

(2) Except as provided in paragraph (a)(4) of this section, you must determine the quarterly mass or volume of contents in all containers if you receive CO₂ in containers by following the most appropriate of the following procedures:

(i) You may measure the mass of contents of containers summed quarterly using weigh bills, scales, or load cells.

(ii) You may determine the volume of the contents of containers summed quarterly.

(iii) If you took ownership of the CO₂ in a commercial transaction, you may use the quarterly mass or volume of contents from the sales contract if it is a one-time transaction or from invoices or manifests if it is an ongoing commercial transaction with discrete shipments.

(3) Except as provided in paragraph (a)(4) of this section, you must determine a quarterly concentration of the CO₂ received that is representative of all CO₂ received in that quarter by following the most appropriate of the following procedures:

(i) You may sample the CO₂ stream at least once per quarter at the point of receipt and measure its CO₂ concentration.

(ii) If you took ownership of the CO₂ in a commercial transaction for which the sales contract was contingent on CO₂ concentration, and if the supplier of the CO₂ sampled the CO₂ stream in a quarter and measured its concentration per the sales

contract terms, you may use the CO₂ concentration data from the sales contract for that quarter.

(iii) If you inject CO₂ from a production process unit that is part of your facility, you may report the quarterly CO₂ concentration of the CO₂ stream supplied that was measured following the procedures provided in subpart PP of this part.

(4) If the CO₂ you receive is wholly injected and is not mixed with any other supply of CO₂, you may report the annual mass of CO₂ injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO₂ received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO₂ received.

(5) You must assume that the CO₂ you receive meets the definition of a CO₂ stream unless you can trace it through written records to a source other than a CO₂ stream.

(b) CO₂ injected.

(1) You must select a point or points of measurement at which the CO₂ stream(s) is representative of the CO₂ stream(s) being injected. You may use as the point or points of measurement the location(s) of the flow meter(s) used to comply with the flow monitoring and reporting provisions in your Underground Injection Control permit.

(2) You must measure flow rate of CO₂ injected with a flow meter and collect the flow rate quarterly.

(3) You must sample the injected CO₂ stream at least once per quarter immediately upstream or downstream of the flow meter used to measure flow rate of that CO₂ stream and measure the CO₂ concentration of the sample.

(c) CO₂ produced.

(1) The point of measurement for the quantity of CO₂ produced from oil or other fluid production wells is a flow meter directly downstream of each separator that sends a stream of gas into a recycle or end use system.

(2) You must sample the produced gas stream at least once per quarter immediately upstream or downstream of the flow meter used to measure flow rate of that gas stream and measure the CO₂ concentration of the sample.

(3) You must measure flow rate of gas produced with a flow meter and collect the flow rate quarterly.

(d) CO₂ emissions from equipment leaks and vented emissions of CO₂. If you have equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead or between the flow meter used to measure production quantity and the production wellhead, you must follow the monitoring and QA/QC requirements specified in subpart W of this part for the equipment.

(e) Measurement devices.

(1) All flow meters must be operated continuously except as necessary for maintenance and calibration.

(2) You must calibrate all flow meters used to measure quantities reported in § 98.446 according to the calibration and accuracy requirements in § 98.3(i).

(3) You must operate all measurement devices according to one of the following. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or an industry standard practice. 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).

(4) You must ensure that any flow meter calibrations performed are National Institute of Standards and Technology (NIST) traceable.

(f) General.

(1) If you measure the concentration of any CO₂ quantity for reporting, you must measure according to one of the following. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or an industry standard practice.

(2) You must convert all measured volumes of CO₂ to the following standard industry temperature and pressure conditions for use in Equations RR-2, RR-5 and RR-8 of this subpart: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere.

(3) For 2011, you may follow the provisions of § 98.3(d)(1) through (2) for best available monitoring methods only for parameters required by paragraphs (a) and (b) of § 98.443 rather than follow the monitoring requirements of paragraph (a) of this section. For purposes of this subpart, any reference to the year 2010 in § 98.3(d)(1) through (2) shall mean 2011.

§ 98.445 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG quantities calculations is required. Whenever the monitoring procedures cannot be followed, you must use the following missing data procedures:

(a) A quarterly flow rate of CO₂ received that is missing must be estimated as follows:

(1) Another calculation methodology listed in § 98.444(a)(1) must be used if possible.

(2) If another method listed in § 98.444(a)(1) cannot be used, a quarterly flow rate value that is missing must be estimated using a representative flow rate value from the nearest previous time period.

(b) A quarterly mass or volume of contents in containers received that is missing must be estimated as follows:

(1) Another calculation methodology listed in § 98.444(a)(2) must be used if possible.

(2) If another method listed in § 98.444(a)(2) cannot be used, a quarterly mass or volume value that is missing must be estimated using a representative mass or volume value from the nearest previous time period.

(c) A quarterly CO₂ concentration of a CO₂ stream received that is missing must be estimated as follows:

(1) Another calculation methodology listed in § 98.444(a)(3) must be used if possible.

(2) If another method listed in § 98.444(a)(3) cannot be used, a quarterly concentration value that is missing must be estimated using a representative concentration value from the nearest previous time period.

(d) A quarterly quantity of CO₂ injected that is missing must be estimated using a representative quantity of CO₂ injected from the nearest previous period of time at a similar injection pressure.

(e) For any values associated with CO₂ emissions from equipment leaks and vented emissions of CO₂ from surface equipment at the facility that are reported in this subpart, missing data estimation procedures should be followed in accordance with those specified in subpart W of this part.

(f) The quarterly quantity of CO₂ produced from subsurface geologic formations that is missing must be estimated using a representative quantity of CO₂ produced from the nearest previous period of time.

(g) You must estimate the mass of CO₂ emitted by surface leakage that is missing as required by your approved MRV plan.

(h) You must estimate other missing data as required by your approved MRV plan.

§ 98.446 Data reporting requirements.

In addition to the information required by § 98.3(c), report the information listed in this section.

(a) If you receive CO₂ by pipeline, report the following for each receiving flow meter:

(1) The total net mass of CO₂ received (metric tons) annually.

(2) If a volumetric flow meter is used to receive CO₂ report the following unless you reported yes to paragraph (a)(4) of this section:

(i) The volumetric flow through a receiving flow meter at standard conditions (in standard cubic meters) in each quarter.

(ii) The volumetric flow through a receiving flow meter that is redelivered to another facility without being injected into your well (in standard cubic meters) in each quarter.

(iii) The CO₂ concentration in the flow (volume percent CO₂ expressed as a decimal fraction) in each quarter.

(3) If a mass flow meter is used to receive CO₂ report the following unless you reported yes to paragraph (a)(4) of this section:

(i) The mass flow through a receiving flow meter (in metric tons) in each quarter.

(ii) The mass flow through a receiving flow meter that is redelivered to another facility without being injected into your well (in metric tons) in each quarter.

(iii) The CO₂ concentration in the flow (weight percent CO₂ expressed as a decimal fraction) in each quarter.

(4) If the CO₂ received is wholly injected and not mixed with any other supply of CO₂, report whether you followed the procedures in § 98.444(a)(4).

(5) The standard or method used to calculate each value in paragraphs (a)(2) through (a)(3) of this section.

(6) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (a)(2) through (a)(3) of this section.

(7) Whether the flow meter is mass or volumetric.

(8) A numerical identifier for the flow meter.

(b) If you receive CO₂ in containers, report:

(1) The mass (in metric tons) or volume at standard conditions (in standard cubic meters) of contents in containers received in each quarter.

(2) The concentration of CO₂ of contents in containers (volume or wt. percent CO₂ expressed as a decimal fraction) in each quarter.

(3) The mass (in metric tons) or volume (in standard cubic meters) of contents in containers that is redelivered to another facility without being injected into your well in each quarter.

(4) The net mass of CO₂ received (in metric tons) annually.

(5) The standard or method used to calculate each value in paragraphs (b)(1), (b)(2), and (b)(3) of this section.

(6) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (b)(1) and (b)(2) of this section.

(c) If you use more than one receiving flow meter, report the total net mass of CO₂ received (metric tons) through all flow meters annually.

(d) The source of the CO₂ received according to the following categories:

(1) CO₂ production wells.

(2) Electric generating unit.

(3) Ethanol plant.

(4) Pulp and paper mill.

(5) Natural gas processing.

(6) Gasification operations.

(7) Other anthropogenic source.

(8) Discontinued enhanced oil and gas recovery project.

(9) Unknown.

(e) Report the date that you began collecting data for calculating total amount sequestered according to § 98.448(a)(7) of this subpart.

(f) Report the following. If the date specified in paragraph (e) of this section is during the reporting year for this annual report, report the following starting on the date specified in paragraph (e) of this section.

(1) For each injection flow meter (mass or volumetric), report:

(i) The mass of CO₂ injected (metric tons) annually.

(ii) The CO₂ concentration in flow (volume or weight percent CO₂ expressed as a decimal fraction) in each quarter.

(iii) If a volumetric flow meter is used, the volumetric flow rate at standard conditions (in standard cubic meters) in each quarter.

(iv) If a mass flow meter is used, the mass flow rate (in metric tons) in each quarter.

(v) A numerical identifier for the flow meter.

(vi) Whether the flow meter is mass or volumetric.

(vii) The standard used to calculate each value in paragraphs (f)(1)(ii) through (f)(1)(iv) of this section.

(viii) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (f)(1)(ii) through (f)(1)(iv) of this section.

(ix) The location of the flow meter.

(2) The total CO₂ injected (metric tons) in the reporting year as calculated in Equation RR-6 of this subpart.

(3) For CO₂ emissions from equipment leaks and vented emissions of CO₂, report the following:

(i) The mass of CO₂ emitted (in metric tons) annually from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

(ii) The mass of CO₂ emitted (in metric tons) annually from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.

(4) For each separator flow meter (mass or volumetric), report:

(i) CO₂ mass produced (metric tons) annually.

(ii) CO₂ concentration in flow (volume or weight percent CO₂ expressed as a decimal fraction) in each quarter.

(iii) If a volumetric flow meter is used, volumetric flow rate at standard conditions (standard cubic meters) in each quarter.

(iv) If a mass flow meter, mass flow rate (metric tons) in each quarter.

(v) A numerical identifier for the flow meter.

(vi) Whether the flow meter is mass or volumetric.

(vii) The standard used to calculate each value in paragraphs (f)(4)(ii) through (f)(4)(iv) of this section.

(viii) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (f)(4)(ii) through (f)(4)(iv) of this section.

(5) The entrained CO₂ in produced oil or other fluid divided by the CO₂ separated through all separators in the reporting year (weight percent CO₂ expressed as a decimal fraction) used as the value for X in Equation RR-9 of this subpart and as determined according to your EPA-approved MRV plan.

(6) Annual CO₂ produced in the reporting year as calculated in Equation RR-9 of this subpart.

(7) For each leakage pathway through which CO₂ emissions occurred, report:

(i) A numerical identifier for the leakage pathway.

(ii) The CO₂ (metric tons) emitted through that pathway in the reporting year.

(8) Annual CO₂ mass emitted (metric tons) by surface leakage in the reporting year as calculated by Equation RR-10 of this subpart.

(9) Annual CO₂ (metric tons) sequestered in subsurface geologic formations in the reporting year as calculated by Equation RR-11 or RR-12 of this subpart.

(10) Cumulative mass of CO₂ (metric tons) reported as sequestered in subsurface geologic formations in all years since the well or group of wells became subject to reporting requirements under this subpart.

(11) Date that the most recent MRV plan was approved by EPA and the MRV plan approval number that was issued by EPA.

(12) An annual monitoring report that contains the following components:

(i) A narrative history of the monitoring efforts conducted over the previous calendar year, including a listing of all monitoring equipment that was operated, its period of operation, and any relevant tests or surveys that were conducted.

(ii) A description of any changes to the monitoring program that you concluded were not material changes warranting submission of a revised MRV plan under § 98.448(d).

(iii) A narrative history of any monitoring anomalies that were detected in the previous calendar year and how they were investigated and resolved.

(iv) A description of any surface leakages of CO₂, including a discussion of all methodologies and technologies involved in detecting and quantifying the surface leakages and any assumptions and uncertainties involved in calculating the amount of CO₂ emitted.

(13) If a well is permitted under the Underground Injection Control program, for each injection well, report:

- (i) The well identification number used for the Underground Injection Control permit.
- (ii) The Underground Injection Control permit class.

(14) If an offshore well is not subject to the Safe Drinking Water Act, for each injection well, report any well identification number and any identification number used for the legal instrument authorizing geologic sequestration.

§ 98.447 Records that must be retained.

(a) You must follow the record retention requirements specified by § 98.3(g). In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a)(1) through (7) of this section, as applicable. You must retain all required records for at least 3 years.

(1) Quarterly records of CO₂ received, including mass flow rate of contents of containers (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(2) Quarterly records of produced CO₂, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(3) Quarterly records of injected CO₂ including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(4) Annual records of information used to calculate the CO₂ emitted by surface leakage from leakage pathways.

(5) Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

(6) Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.

(7) Any other records as specified for retention in your EPA-approved MRV plan.

(b) You must complete your monitoring plans, as described in § 98.3(g)(5), by April 1 of the year you begin collecting data.

§ 98.448 Geologic sequestration monitoring, reporting, and verification (MRV) plan.

(a) **Contents of MRV plan.** You must develop and submit to the Administrator a proposed MRV plan for monitoring, reporting, and verification of geologic sequestration at your facility. Your proposed MRV plan must contain the following components:

- (1) Delineation of the maximum monitoring area and the active monitoring areas. The first period for your active monitoring area will begin from the date determined in your MRV plan through the date at which the plan calls for the first expansion of the monitoring area. The length of each monitoring period can be any time interval chosen by you that is greater than 1 year.
- (2) Identification of potential surface leakage pathways for CO₂ in the maximum monitoring area and the likelihood, magnitude, and timing, of surface leakage of CO₂ through these pathways.
- (3) A strategy for detecting and quantifying any surface leakage of CO₂.
- (4) A strategy for establishing the expected baselines for monitoring CO₂ surface leakage.
- (5) A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation. This includes, but is not limited to, considerations for calculating CO₂ emissions from equipment leaks and vented emissions of CO₂ between the injection flow meter and injection well and/or the production flow meter and production well, and considerations for calculating CO₂ in produced fluids.
- (6) If a well is permitted under the Underground Injection Control program, for each injection well, report the well identification number used for the Underground Injection Control permit and the Underground Injection Control permit class. If the well is not yet permitted, and you have applied for an Underground Injection Control permit, report the well identification numbers in the permit application. If an offshore well is not subject to the Safe Drinking Water Act, for each injection well, report any well identification number and any identification number used for the legal instrument authorizing geologic sequestration. If you are submitting your Underground Injection Control permit application as part of your proposed MRV plan, you must notify EPA when the permit has been approved. If you are an offshore facility not subject to the Safe Drinking Water Act, and are submitting your application for the legal instrument authorizing geologic sequestration as part of your proposed MRV plan, you must notify EPA when the legal instrument authorizing geologic sequestration has been approved.
- (7) Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart. This date must be after expected baselines as required by paragraph (a)(4) of this section are established and the leakage detection and quantification strategy as required by paragraph (a)(3) of this section is implemented in the initial AMA.

(b) **Timing.** You must submit a proposed MRV plan to EPA according to the following schedule:

- (1) You must submit a proposed MRV plan to EPA by June 30, 2011 if you were issued a final Underground Injection Control permit authorizing the injection of CO₂ into the subsurface on or before December 31, 2010. You will be allowed to request one extension of up to an additional 180 days in which to submit your proposed MRV plan.

(2) You must submit a proposed MRV plan to EPA within 180 days of receiving a final Underground Injection Control permit authorizing the injection of CO₂ into the subsurface. If your facility is an offshore facility not subject to the Safe Drinking Water Act, you must submit a proposed MRV plan to EPA within 180 days of receiving authorization to begin geologic sequestration of CO₂. You will be allowed to request one extension of the submittal date of up to an additional 180 days.

(3) If you are injecting a CO₂ stream in subsurface geologic formations to enhance the recovery of oil or natural gas and you are not permitted as Class VI under the Underground Injection Control program, you may opt to submit an MRV plan at any time.

(4) If EPA determines that your proposed MRV plan is incomplete, you must submit an updated MRV plan within 45 days of EPA notification, unless otherwise specified by EPA.

(c) **Final MRV plan.** The Administrator will issue a final MRV plan within a reasonable period of time. The Administrator's final MRV plan is subject to the provisions of [part 78 of this chapter](#). Once the MRV plan is final and no longer subject to administrative appeal under [part 78 of this chapter](#), you must implement the plan starting on the day after the day on which the plan becomes final and is no longer subject to such appeal.

(d) **MRV plan revisions.** You must revise and submit the MRV plan within 180 days to the Administrator for approval if any of the following in paragraphs (d)(1) through (d)(4) of this section applies. You must include the reason(s) for the revisions in your submittal.

(1) A material change was made to monitoring and/or operational parameters that was not anticipated in the original MRV plan. Examples of material changes include but are not limited to: Large changes in the volume of CO₂ injected; the construction of new injection wells not identified in the MRV plan; failures of the monitoring system including monitoring system sensitivity, performance, location, or baseline; changes to surface land use that affects baseline or operational conditions; observed plume location that differs significantly from the predicted plume area used for developing the MRV plan; a change in the maximum monitoring area or active monitoring area; or a change in monitoring technology that would result in coverage or detection capability different from the MRV plan.

(2) A change in the permit class of your Underground Injection Control permit.

(3) If you are notified by EPA of substantive errors in your MRV plan or monitoring report.

(4) You choose to revise your MRV plan for any other reason in any reporting year.

(e) **Revised MRV plan.** The requirements of paragraph (c) of this section apply to any submission of a revised MRV plan. You must continue reporting under your currently approved plan while awaiting approval of a revised MRV plan.

(f) **Format.** Each proposed MRV plan or revision and each annual report must be submitted electronically in a format specified by the Administrator.

(g) **Certificate of representation.** You must submit a certificate of representation according to the provisions in § 98.4 at least 60 days before submission of your MRV plan, your research and development exemption request, your MRV plan submission extension request, or your initial annual report under this part, whichever is earlier.

§ 98.449 Definitions.

Except as provided below, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Active monitoring area is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas:

- (1) The area projected to contain the free phase CO₂ plume at the end of year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile.
- (2) The area projected to contain the free phase CO₂ plume at the end of year t + 5.

CO₂ received means the CO₂ stream that you receive to be injected for the first time into a well on your facility that is covered by this subpart. CO₂ received includes, but is not limited to, a CO₂ stream from a production process unit inside your facility and a CO₂ stream that was injected into a well on another facility, removed from a discontinued enhanced oil or natural gas or other production well, and transferred to your facility.

Equipment leak means those emissions that could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Expected baseline is the anticipated value of a monitored parameter that is compared to the measured monitored parameter.

Maximum monitoring area means the area that must be monitored under this regulation and is defined as equal to or greater than the area expected to contain the free phase CO₂ plume until the CO₂ plume has stabilized plus an all-around buffer zone of at least one-half mile.

Offshore means seaward of the terrestrial borders of the United States, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of the United States under the Outer Continental Shelf Lands Act.

Research and development project means a project for the purpose of investigating practices, monitoring techniques, or injection verification, or engaging in other applied research, that will enable safe and effective long-term containment of a CO₂ stream in subsurface geologic formations, including research and short duration CO₂ injection tests conducted as a precursor to long-term storage.

Separator means a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.

Surface leakage means the movement of the injected CO₂ stream from the injection zone to the surface, and into the atmosphere, indoor air, oceans, or surface water.

Underground Injection Control permit means a permit issued under the authority of Part C of the Safe Drinking Water Act at [42 U.S.C. 300h](https://www.ecfr.gov/current/title-40/chapter-I/subchapter-D/part-146/subpart-C) et seq.

Underground Injection Control program means the program responsible for regulating the construction, operation, permitting, and closure of injection wells that place fluids underground for storage or disposal for purposes of protecting underground sources of drinking water from endangerment pursuant to Part C of the Safe Drinking Water Act at [42 U.S.C. 300h](https://www.ecfr.gov/current/title-40/chapter-I/subchapter-D/part-146/subpart-C) et seq.

Vented emissions means intentional or designed releases of CH₄ or CO₂ containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).