Petroleum Refineries

Subpart Y, Greenhouse Gas Reporting Program

OVERVIEW

Subpart Y of the Greenhouse Gas Reporting Program (GHGRP) (40 CFR 98.250 – 98.258) applies to any facility that contains a petroleum refineries process and meets the Subpart Y source category definition. Some subparts have thresholds that determine applicability for reporting, and some do not. To decide whether your facility must report under this subpart, please refer to 40 CFR 98.251 and the GHGRP Applicability Tool.

This Information Sheet is intended to help facilities reporting under Subpart Y understand how the source category is defined, what greenhouse gases (GHGs) must be reported, how GHG emissions must be calculated and shared with EPA, and where to find more information.

How is This Source Category Defined?

Petroleum refineries are facilities that produce gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) through distillation of petroleum or the redistillation, cracking, or reforming of unfinished petroleum derivatives.

Facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not included in this subpart as petroleum refineries, regardless of the products produced.

What GHGs Must Be Reported?

The greenhouse gases (GHGs) that must be reported under Subpart Y are listed in Table 1. For refinery processes that are subject to subparts other than Subpart Y, the calculation methods required for carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) are specified by subpart. Refer to the relevant Information Sheets (Subparts C, P, X, MM, and WW) for a summary of the emissions reporting requirements and calculations.

If multiple Greenhouse Gas Reporting Program (GHGRP) source categories are co-located at a facility, the facility may need to report GHG emissions under a different subpart. Please refer to the relevant Information Sheet for a summary of the rule requirements for any other source categories located at the facility.

Table 1. GHG Reporting Requirements for Subpart Y Petroleum Refinery Processes

Refinery Process	Applicable Subpart		
	Carbon Dioxide (CO_2)	Methane (CH_4)	Nitrous Oxide (N_2O)
Stationary combustion	Subpart C*	Subpart C	Subpart C
Flares	Subpart Y	Subpart Y	Subpart Y
Catalytic cracking	Subpart Y	Subpart Y	Subpart Y
Traditional fluid coking	Subpart Y	Subpart Y	Subpart Y
Fluid coking with flexicoking design	Subpart C/Y	Subpart C/Y	Subpart C/Y
Catalytic reforming	Subpart Y	Subpart Y	Subpart Y
Onsite and offsite sulfur recovery	Subpart Y	—	—
Asphalt blowing	Subpart Y	Subpart Y	—
Equipment leaks	—	Subpart Y	—
Storage tanks	—	Subpart Y	—
Delayed coking	—	Subpart Y	—
Other process vents	Subpart Y	Subpart Y	Subpart Y
Uncontrolled blowdown systems	—	Subpart Y	—
Loading operations	—	Subpart Y	—
Hydrogen production	Subpart P	—	—
Petrochemical Plants	Subpart X	Subpart X	Subpart X
Suppliers of Petroleum Products	Subpart MM	—	—
Coke Calcining	Subpart WW	Subpart WW	Subpart WW

* *CO_2 emissions from combustion of fuel gas must generally be calculated using either the Tier 3 (Equation C-5) or Tier 4 Calculation Methodology; however, there are certain exceptions, when a flow meter is not present, for low flow streams, small units and streams composed of only vapors from certain sources. See the regulatory text for details.*

Key:

- **Subpart C** = General Stationary Combustion Sources, found at 40 CFR 98.30 – 98.38
- **Subpart P** = Hydrogen Production, found at 40 CFR 98.160 – 98.168
- **Subpart Y** = Petroleum Refineries, found at 40 CFR 98.250 – 98.258
- **Subpart X** = Petrochemical, found at 40 CFR 98.240 – 98.248
- **Subpart MM** = Suppliers of Petroleum Products, found at 40 CFR 98.390 – 98.398
- **Subpart WW** = Coke Calciners, found at 40 CFR 98.490 – 98.498
- — = Reporting is not required

How Must GHG Emissions Be Calculated?

Under Subpart Y, petroleum refinery facility reporters must calculate CO_2, CH_4 and N_2O emissions using the calculation methods described below for each refinery process.

For processes designated below with "[CEMS]", refinery units with certain types of continuous emission monitoring systems (CEMS) in place must report using the CEMS and follow the Tier 4 Calculation Methodology of Subpart C, found at 40 CFR 98.30 – 98.38, to report combined process and combustion CO_2 emissions. For refinery units without CEMS in place, reporters can elect to either:

(1) Install and operate a CEMS to measure combined process and combustion CO_2 emissions according to the requirements specified in Subpart C; or

(2) Calculate CO_2 emissions using the methods summarized below.

Flares

CO_2 emissions from flares must be calculated using the gas flow rate (either measured with a continuous flow meter or estimated using engineering calculations) and either:

(1) The daily or weekly measured carbon (C) content of the flare gas; or

(2) The daily or weekly measured heat content of the flare gas and a default emission factor (EF) provided in the rule.

If the C content and heat content of the gas are not measured at least weekly, engineering estimates of heat content during normal flare operations may be used, but CO_2 emissions from each startup, shutdown, and malfunction event exceeding 500,000 standard cubic feet per day (scf/day) must be calculated separately, also using engineering estimates. CH_4 and N_2O emissions from flares must be calculated using the default fuel gas EFs specified in Subpart C.

Catalytic Cracking Units, Fluid Coking Units [CEMS]

For catalytic cracking units and traditional fluid coking units with rated capacities greater than 10,000 barrels per stream day (bbls/sd), continuously, or no less frequently than hourly, monitor the oxygen (O_2), CO_2, and (if necessary) carbon monoxide (CO) concentrations in the exhaust stacks from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels. Calculate CO_2 emissions using the volumetric flow rate of the exhaust gas (measured or calculated) and the measured CO and CO_2 concentrations in the exhaust stacks.

For catalytic cracking units and traditional fluid coking units with rated capacities of 10,000 bbls/sd or less, either:

(1) Monitor continuously or no less than daily the O_2, CO_2, and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels. Calculate CO_2 emissions using the same method used for units with rated capacities greater than 10,000 bbls/sd; or

(2) Calculate CO_2 emissions from each catalytic cracking unit and traditional fluid coking unit using the annual throughput (from company records), a coke burn-off factor (engineering calculations or default value) and the C content of the coke (either measured or default value).

If there is a CO boiler that uses auxiliary fuels or combusts materials other than catalytic cracking unit or fluid coking unit exhaust gas, determine the CO_2 emissions resulting from the combustion of these fuels or other materials following the requirements in Subpart C.

Calculate CH_4 and N_2O emissions using unit-specific measurement data, unit-specific EFs based on a source test of the unit, or the calculated CO_2 emissions multiplied by the ratio of the Subpart C petroleum products default CH_4 or N_2O EF to the Subpart C petroleum coke default CO_2 EF.

Fluid coking units that use the flexicoking design may account for their GHG emissions either by using the methods specified for catalytic cracking units and traditional fluid coking units or by using the methods for stationary combustion specified in Subpart C.

Catalytic Reforming Units [CEMS]

For catalytic reforming units either:

(1) Monitor continuously, or no less frequently than daily, the O_2, CO_2, and (if necessary) CO concentrations in the exhaust stack from the catalytic reforming unit catalyst regenerator prior to the combustion of other fossil fuels, and calculate CO_2 emissions according to the same requirements of 40 CFR 98.253(c)(2)(i) through (iii) for catalytic cracking units and fluid coking units with rated capacities greater than10,000 bbls/sd; or

(2) Calculate CO_2 emissions from the catalytic reforming unit catalyst regenerator using the quantity of coke burn-off per regeneration cycle or measurement period (engineering estimates), the C content of the coke (measured, engineering estimate, or default value), and the number of regeneration cycles

or measurement periods.

Calculate CH_4 and N_2O emissions using the same methods found at 40 CFR 98.253(c)(4) and (5), for catalytic cracking units and traditional fluid coking units.

On-site and Off-site Sulfur (S) Recovery [CEMS]

For Claus S recovery units, CO_2 emissions must be calculated using the volumetric flow rate of the sour gas (measured continuously or estimated from engineering calculations, company records or similar estimates) and the C content of the sour gas stream (using a measured data, engineering estimates, or a default value).

For non-Claus S recovery units, calculate CO_2 emissions using either the method described for Claus S recovery units above or the methods described under *"Other Process Vents*" regardless of the CO_2 concentration.

Asphalt Blowing Operations

CO_2 and CH_4 emissions from asphalt blowing operations may use either the method described under *"Other Process Vents*" regardless of the CO_2 and CH_4 concentration or the method described below.

For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing or another non-combustion control device, CO_2 and CH_4 emissions must be calculated using facility-specific EFs based on test data or, where test data are not available, default EFs provided in the rule. For asphalt blowing operations controlled by a thermal oxidizer, flare, or other vapor combustion control device, CH_4 and CO_2 emissions must be calculated by assuming that 98% of the CH_4 and other hydrocarbons (HCs) generated by the asphalt blowing operation are converted to CO_2.

Delayed Coking Units (DCUs)

CH_4 emissions from DCUs during decoking operations (venting, draining, deheading, and coke-cutting) must be calculated using a heat balance steam generation model. Key inputs to this heat balance include the mass of water and coke in the coke drum vessel and the average temperature of the coke drum contents when venting first occurs. As an alternative to monitoring the average temperature of the coke drum, this calculation method provides a temperature-pressure correlation. Finally, if a reporter has DCU vent gas measurements, these measurements can be used to develop a unit-specific CH_4 EF for use with the steam generation model.

Other Process Vents

GHG emissions from other process vents that contain CO_2, CH_4, or N_2O exceeding concentration thresholds specified in the rule must be calculated using the volumetric flow rate (measurement data, process knowledge, or engineering estimates), the mole fraction of the GHG in the exhaust gas (measurement data, process knowledge, or engineering estimates), and the number of hours per venting event.

Uncontrolled Blowdown Systems

CH_4 emissions from uncontrolled blowdown systems must be calculated using either the method specified for "*Other Process Vents*" regardless of the CH_4 concentration or a default EF and the sum of crude oil and intermediate products received from off-site and processed at the facility.

Equipment Leaks

CH_4 emissions from equipment leaks must be calculated using either equipment-type specific default EFs or process specific CH_4 composition data and leak data collected using the leak detection methods specified in *EPA's Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017, NTIS PB96-175401).

Storage Tanks

For storage tanks, the calculation methodology used to calculate the CH_4 emissions depends on the material stored. For storage tanks used to store unstabilized crude oil, facilities must use either:

(1) The tank-specific CH_4 composition data (measured or product knowledge) and the measured gas generation rate; or

(2) An EF-based method using the quantity of unstabilized crude oil received at the facility, the pressure difference between the previous storage pressure and atmospheric pressure, the mole fraction of CH_4 in the vented gas (measured or a default value), and an EF provided in the rule.

For storage tanks that store material other than unstabilized crude oil, facilities must use either:

(1) The tank-specific CH_4 composition data and the emission estimation methods provided in *Section 7.1 of AP-42: Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources* for each storage tank with a vapor-phase CH_4 concentration of 0.5% by volume or more; or

(2) The quantity of crude oil plus intermediate products received from off-site that are processed at the facility and a default EF specified in the rule.

Loading Operations

CH_4 emissions from loading operations must be calculated using vapor-phase CH_4 composition data (measured or process knowledge) and the emission estimation procedures provided in *Section 5.2 of AP-42: Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources*. Facilities must calculate CH_4 emissions only for loading materials that have an equilibrium vapor-phase CH_4 concentration equal to or greater than 0.5% by volume.

A checklist for data that must be monitored is available here: Subpart Y Monitoring Checklist.

What Information Must Be Reported?

In addition to the information required by the General Provisions in Subpart A, found at 40 CFR 98.3(c), the following must be reported:

- Data used to identify emission units and calculate the GHG emissions (e.g., unit ID, unit type, feed input, GHG calculation method, etc.); and
- GHG emissions at the unit level for each flare, catalytic cracking unit, fluid coking unit, catalytic reforming unit, on-site and off-site S recovery plant, asphalt blowing operations, DCU, and process vent.

What Records Must Be Maintained?

Reporters are required to retain records that pertain to their annual GHGRP report for at least three years after the date the report is submitted. Please see the Subpart A Information Sheet and 40 CFR 98.3(g) for general recordkeeping requirements. Specific recordkeeping requirements for Subpart Y are listed at 40 CFR 98.257.

When and How Must Reports Be Submitted?

Reporters must submit their annual GHGRP reports for the previous calendar year to the EPA by March 31st, unless the 31st falls on a Saturday, Sunday, or federal holiday, in which case reports are due on the next business day. Annual reports must be submitted electronically using the electronic Greenhouse Gas Reporting Tool (e-GGRT), the GHGRP's online reporting system.

Additional information on setting up user accounts, registering a facility, and submitting annual reports is available on the GHGRP Help webpage.

When Can a Facility Stop Reporting?

A facility may discontinue reporting under several scenarios, which are summarized in Subpart A (found at 40 CFR 98.2(i)) and the Subpart A Information Sheet.

For More Information

For additional information on Subpart Y, please visit the Subpart Y webpage. For additional information on the GHGRP, please visit the GHGRP website, which includes additional information sheets, data previously reported to the GHGRP, training materials, and links to Frequently Asked Questions (FAQs). For questions that cannot be answered through the GHGRP website, please contact us at: GHGreporting@epa.gov.

This Information Sheet is provided solely for informational purposes. It does not replace the need to read and comply with the regulatory text contained in the rule. Rather, it is intended to help reporting facilities and suppliers understand key provisions of the GHGRP. It does not provide legal advice; have a legally binding effect; or expressly or implicitly create, expand, or limit any legal rights, obligations, responsibilities, expectations, or benefits with regard to any person or entity.