Petroleum Refineries

Subpart Y, Greenhouse Gas Reporting Program

Under the Mandatory Reporting of Greenhouse Gases (GHGs) rule, owners or operators of facilities that refine petroleum must report emissions from petroleum refining processes (subpart Y) and all other source categories located at the facility for which methods are defined in the rule, which may include stationary source combustion (subpart C), process emissions from hydrogen production plants (subpart P), process emissions from petrochemical plants (subpart X), and supplier of petroleum product emissions (subpart MM). Owners and operators are required to collect feedstock and product or emission data; calculate GHG emissions; and follow the specified procedures for quality assurance, missing data, recordkeeping, and reporting per the requirements of 40 CFR Part 98 Subpart Y – Petroleum Refineries.

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) by the 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 petroleum refineries, regardless of the products produced.

What Greenhouse Gases Must Be Reported?

The refinery processes and gases that must be reported are listed in the table below along with the rule subpart that specifies the calculation methodology that must be used. *Please note the table key on page 2.*

Table 1. Reporting Requirements for Refinery Processes

For this refinery process…	Report emissions of the listed GHGs by following the requirements of the 40 CFR part 98, subpart indicated…		
	Carbon Dioxide (CO_2)	**Methane (CH_4)**	**Nitrous Oxide (N_2O)**
Stationary combustion	C	C	C
Stationary combustion using fuel gas	C: Tier 3 (Equation C-5) or Tier 4[a]	C	C
Flares	Y	Y	Y
Catalytic cracking	Y	Y	Y
Traditional fluid coking	Y	Y	Y
Fluid coking with flexicoking design	C/Y	C/Y	C/Y
Catalytic reforming	Y	Y	Y
Onsite and offsite sulfur recovery	Y	-	-
Coke calcining	Y	Y	Y
Asphalt blowing	Y	Y	-
Equipment leaks	-	Y	-
Storage tanks	-	Y	-
Delayed coking	-	Y	-
Other process vents	Y	Y	Y
Uncontrolled blowdown systems	-	Y	-
Loading operations	-	Y	-
Hydrogen plants (nonmerchant)	P	-	-
Petrochemical Plants	X	X	X
Suppliers of Petroleum Products	MM	-	-

[a] For CO_2 emissions from combustion of fuel gas, the Tier 3 (equation C-5) or Tier 4 methodology must be used, as stated in the rule. Rule text supersedes preamble text when inconsistencies occur.

Key:

C = 40 CFR part 98, subpart C (General Stationary Combustion Sources)

P = 40 CFR part 98, subpart P (Hydrogen Production)

Y = 40 CFR part 98, subpart Y (Petroleum Refineries)

X = 40 CFR part 98, subpart X (Petrochemical Production)

MM = 40 CFR part 98, subpart MM (Suppliers of Petroleum Products)

- = Reporting from this process is not required

For refinery processes that are subject to subparts other than 40 CFR part 98, subpart Y, the information sheets for 40 CFR part 98, subparts C, P, X and MM summarize the requirements for calculating and reporting emissions.

How Must Greenhouse Gas Emissions Be Calculated?

Under 40 CFR part 98, subpart Y, owners or operators of petroleum refineries 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 methodology of 40 CFR part 98, subpart C 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 40 CFR part 98, 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 content of the flare gas; or

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

If the carbon content and heat content of the gas are not measured at least weekly, engineering estimates of heat content during normal flare use may be used, but CO_2 emissions from each startup, shutdown, and malfunction event exceeding 500,000 scf/day must be calculated separately, also using engineering estimates. CH_4 and N_2O emissions from flares must be calculated using the emission factors specified in 40 CFR part 98, subpart C.

Catalytic Cracking Units, Fluid Coking Units [CEMS]

For catalytic cracking units and 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 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, and 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 fluid coking unit using a coke burn-off factor and the carbon 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 and report those emissions by following the requirements of subpart C.

Calculate CH_4 and N_2O emissions using unit-specific measurement data, unit-specific emission factors based on a source test of the unit, or the equations specified in the rule.

Fluid coking units that use the flexicoking design may account for their GHG emissions either by using the methods specified for traditional fluid coking units, or by using the methods for stationary combustion specified in 40 CFR part 98, 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 part 98.253(c)(2)(i) through (iii) for catalytic cracking units and fluid coking units with rated capacities of 10,000 bbls/sd or less; or
(2) Calculate CO_2 emissions from the catalytic reforming unit catalyst regenerator using the quantity of coke burned off, the carbon content of the coke (measured or default value), and the number of regeneration cycles.

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

Onsite and Offsite Sulfur Recovery [CEMS]

For Claus sulfur recovery units, CO_2 emissions must be calculated using the volumetric flow rate of the sour gas (measured continuously or estimated from engineering calculations) and the carbon content of the sour gas stream (using a measured or a default value).

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

Coke Calcining Units [CEMS]

CO_2 emissions must be calculated from the difference between the carbon input as green coke and the carbon output as marketable petroleum coke, and as coke dust collected in the dust collection system. Calculate CH_4 and N_2O emissions using the same methods specified in 40 CFR part 98.253(c)(4) and (5) for catalytic cracking units and traditional fluid coking units.

Asphalt Blowing Operations

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

For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, CO_2 and CH_4 emissions must be calculated using facility-specific emission factors based on test data or, where test data are not available, default emission factors provided in the rule. For asphalt blowing operations controlled by a thermal oxidizer or flare, CH_4 and CO_2 emissions must be calculated by assuming that 98 percent of the CH_4 and other hydrocarbons generated by the asphalt blowing operation are converted to CO_2.

Equipment Leaks

CH_4 emissions from equipment leaks must be calculated using either default emission factors 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.

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 (based on direct measurement or product knowledge) and the measured gas generation rate; or
(2) An emission factor-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 (using either a measured or a default value), and an emission factor provided in the rule.

For storage tanks that have a vapor-phase CH_4 concentration of 0.5 percent by volume or more and 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 the AP-42: Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources; or
(2) The default emission factor specified in the rule.

Delayed Coking Units

CH_4 emissions from the depressurization of delayed coking vessels must be calculated by either:

(1) Following the method outlined below for ***Other Process Vents*** and calculating the CH_4 emissions from the subsequent opening of the vessel for coke cutting operations (if water or steam is added to the vessel after it is vented to the atmosphere, this option must be used); or
(2) Calculating the CH_4 emissions from the depressurization vent, the subsequent opening of the vessel for coke cutting operations, and the pressure of the coking vessel when the depressurization gases are first routed to the atmosphere.

On December 9, 2016 (81 FR 89261), the EPA finalized amendments to the delayed coking unit (DCU) emissions calculation methodology. The new method estimates emissions from DCU using a 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, the 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 methane emissions factor for use with the DCU steam generation model. These amendments are effective January 1, 2019 for the RY 2018 report (which must be submitted by March 31, 2019). Reporters must begin to collect the data necessary to calculate emissions in accordance with the amended method beginning January 1, 2018.

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, the mole fraction of the GHG in the exhaust gas, 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*** or a default emission factor and the sum of crude oil and intermediate products received from off site and processed at the facility.

Loading Operations

CH_4 emissions from loading operations must be calculated using the method in Section 5.2 of *AP-42: Compilation of Air Pollution 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 percent by volume.

A checklist for data that must be monitored is available at: https://www.epa.gov/ghgreporting/subpart-y-checklist

What Information Must Be Reported?

In addition to the information required by the General Provisions at 40 CFR 98.3(c), each refinery must report the following information:

- Data used to identify emission units and calculate the GHG emissions (e.g., unit ID, unit type, feed input, GHG calculation method); and
- GHG emissions at the unit level for each catalytic cracking unit, coking unit, catalytic reforming unit, onsite and offsite sulfur recovery plant, coke calcining unit, and process vent.

Facilities must enter required data into the electronic Greenhouse Gas Reporting Tool (e-GGRT) to be reported in the annual report, and must also enter into e-GGRT's *Inputs Verifier Tool* (IVT) the inputs to emission equations for which reporting is not required. IVT uses these entered data to calculate the equation results.

When and How Must Reports Be Submitted?

Annual reports must be submitted by March 31 of each year, unless the 31st is a Saturday, Sunday, or federal holiday, in which case the reports are due on the next business day. Annual reports must be submitted electronically using e-GGRT, the GHGRP's online reporting system. Additional information on setting up user accounts, registering a facility and submitting annual reports is available at https://ccdsupport.com/confluence/.

When Can a Facility Stop Reporting?

There are several scenarios under which a facility may discontinue reporting. These scenarios are summarized in the Subpart A Information Sheet as well as in an FAQ.

For More Information

For additional information on Subpart Y, visit the Subpart Y Resources webpage. For additional information on the Greenhouse Gas Reporting Program, visit the Greenhouse Gas Reporting Program Website, which includes information sheets on other rule subparts, data previously reported to the Greenhouse Gas Reporting Program, training materials, and links to frequently asked questions.

This document is provided solely for informational purposes. It does not provide legal advice, have legally binding effect, or expressly or implicitly create, expand, or limit any legal rights, obligations, responsibilities, expectations, or benefits in regard to any person. The series of information sheets is intended to assist reporting facilities/owners in understanding key provisions of the Greenhouse Gas Reporting Program.