

**§ 98.248 Definitions.**

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

*Product*, as used in § 98.243, means each of the following carbon-containing outputs from a process: the petrochemical, recovered byproducts, and liquid organic wastes that are not combusted onsite. Product does not include process vent emissions, fugitive emissions, or wastewater.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71963, Nov. 29, 2013]

**Subpart Y—Petroleum Refineries****§ 98.250 Definition of source category.**

(a) A petroleum refinery is any facility engaged in producing gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives, except as provided in paragraph (b) of this section.

(b) For the purposes of this subpart, 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.

(c) This source category consists of the following sources at petroleum refineries: Catalytic cracking units; fluid coking units; delayed coking units; catalytic reforming units; coke calcining units; asphalt blowing operations; blowdown systems; storage tanks; process equipment components (compressors, pumps, valves, pressure relief devices, flanges, and connectors) in gas service; marine vessel, barge, tanker truck, and similar loading operations; flares; sulfur recovery plants; and non-merchant hydrogen plants (i.e., hydrogen plants that are owned or under the direct control of the refinery owner and operator).

**§ 98.251 Reporting threshold.**

You must report GHG emissions under this subpart if your facility contains a petroleum refineries process

and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

**§ 98.252 GHGs to report.**

You must report:

(a) CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O combustion emissions from stationary combustion units and from each flare. Calculate and report the emissions from stationary combustion units under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C, except for emissions from combustion of fuel gas. For CO<sub>2</sub> emissions from combustion of fuel gas, use either Equation C-5 in subpart C of this part or the Tier 4 methodology in subpart C of this part, unless either of the conditions in paragraphs (a)(1) or (2) of this section are met, in which case use either Equations C-1 or C-2a in subpart C of this part. For CH<sub>4</sub> and N<sub>2</sub>O emissions from combustion of fuel gas, use the applicable procedures in § 98.33(c) for the same tier methodology that was used for calculating CO<sub>2</sub> emissions. (Use the default CH<sub>4</sub> and N<sub>2</sub>O emission factors for “Fuel Gas” in Table C-2 of this part. For Tier 3, use either the default high heat value for fuel gas in Table C-1 of subpart C of this part or a calculated HHV, as allowed in Equation C-8 of subpart C of this part.) You may aggregate units, monitor common stacks, or monitor common (fuel) pipes as provided in § 98.36(c) when calculating and reporting emissions from stationary combustion units. Calculate and report the emissions from flares under this subpart.

(1) The annual average fuel gas flow rate in the fuel gas line to the combustion unit, prior to any split to individual burners or ports, does not exceed 345 standard cubic feet per minute at 60 °F and 14.7 pounds per square inch absolute and either of the conditions in paragraph (a)(1)(i) or (ii) of this section exist. Calculate the annual average flow rate using company records assuming total flow is evenly distributed over 525,600 minutes per year.

(i) A flow meter is not installed at any point in the line supplying fuel gas or an upstream common pipe.

(ii) The fuel gas line contains only vapors from loading or unloading,

### § 98.253

waste or wastewater handling, and remediation activities that are combusted in a thermal oxidizer or thermal incinerator.

(2) The combustion unit has a maximum rated heat input capacity of less than 30 mmBtu/hr and either of the following conditions exist:

(i) A flow meter is not installed at any point in the line supplying fuel gas or an upstream common pipe; or

(ii) The fuel gas line contains only vapors from loading or unloading, waste or wastewater handling, and remediation activities that are combusted in a thermal oxidizer or thermal incinerator.

(b) CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O coke burn-off emissions from each catalytic cracking unit, fluid coking unit, and catalytic reforming unit under this subpart.

(c) CO<sub>2</sub> emissions from sour gas sent off site for sulfur recovery operations under this subpart. You must follow the calculation methodologies from § 98.253(f) and the monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of this subpart.

(d) CO<sub>2</sub> process emissions from each on-site sulfur recovery plant under this subpart.

(e) CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from each coke calcining unit under this subpart.

(f) CO<sub>2</sub> and CH<sub>4</sub> emissions from asphalt blowing operations under this subpart.

(g) CH<sub>4</sub> emissions from equipment leaks, storage tanks, loading operations, delayed coking units, and uncontrolled blowdown systems under this subpart.

(h) CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from each process vent not specifically included in paragraphs (a) through (g) of this section under this subpart.

(i) CO<sub>2</sub> emissions from non-merchant hydrogen production process units (not including hydrogen produced from catalytic reforming units) following the calculation methodologies, monitoring and QA/QC methods, missing data procedures, reporting require-

### 40 CFR Ch. I (7–1–14 Edition)

ments, and recordkeeping requirements of subpart P of this part.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79160, Dec. 17, 2010; 78 FR 71963, Nov. 29, 2013]

### § 98.253 Calculating GHG emissions.

(a) Calculate GHG emissions required to be reported in § 98.252(b) through (i) using the applicable methods in paragraphs (b) through (n) of this section.

(b) For flares, calculate GHG emissions according to the requirements in paragraphs (b)(1) through (b)(3) of this section.

(1) Calculate the CO<sub>2</sub> emissions according to the applicable requirements in paragraphs (b)(1)(i) through (b)(1)(iii) of this section.

(i) *Flow measurement.* If you have a continuous flow monitor on the flare, you must use the measured flow rates when the monitor is operational and the flow rate is within the calibrated range of the measurement device to calculate the flare gas flow. If you do not have a continuous flow monitor on the flare and for periods when the monitor is not operational or the flow rate is outside the calibrated range of the measurement device, you must use engineering calculations, company records, or similar estimates of volumetric flare gas flow.

(ii) *Heat value or carbon content measurement.* If you have a continuous higher heating value monitor or gas composition monitor on the flare or if you monitor these parameters at least weekly, you must use the measured heat value or carbon content value in calculating the CO<sub>2</sub> emissions from the flare using the applicable methods in paragraphs (b)(1)(ii)(A) and (b)(1)(ii)(B).

(A) If you monitor gas composition, calculate the CO<sub>2</sub> emissions from the flare using either Equation Y-1a or Equation Y-1b of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation Y-1a or Equation Y-1b of this section; otherwise, use weekly values.