an estimate based on engineering judgment of the fraction of the total emissions that is attributable to combustion of off-gas from the ethylene process unit.

(3) Information listed in §98.256(e) of subpart Y of this part for each flare that burns process off-gas.

(4) Name and annual quantity of each feedstock.

(5) Annual quantity of ethylene produced from each process unit (metric tons).


§ 98.247 Records that must be retained.

In addition to the recordkeeping requirements in §98.3(g), you must retain the records specified in paragraphs (a) through (c) of this section, as applicable.

(a) If you comply with the CEMS measurement methodology in §98.243(b), then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in §98.37, records of the procedures used to develop estimates of the fraction of total emissions attributable to combustion of petrochemical process off-gas as required in §98.246(b), and records of any annual average HHV calculations.

(b) If you comply with the mass balance methodology in §98.243(c), then you must retain records of the information listed in paragraphs (b)(1) through (b)(3) of this section.

(1) Results of feedstock or product composition determinations conducted in accordance with §98.243(c)(4).

(2) Start and end times and calculated carbon contents for time periods when off-specification product is produced, if you comply with the alternative methodology in §98.243(c)(4) for determining carbon content of feedstock or product.

(3) A part of the monitoring plan required under §98.3(g)(5), record the estimated accuracy of measurement devices and the technical basis for these estimates.

(4) The dates and results (e.g., percent calibration error) of the calibrations of each measurement device.

(c) If you comply with the combustion methodology in §98.243(d), then you must retain under this subpart the records required for the applicable Tier Calculation Methodologies in §98.37. If you comply with §98.243(d)(2), you must also keep records of the annual average flow calculations.


§ 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 incinerated onsite. Product does not include process vent emissions, fugitive emissions, or wastewater.

Subpart Y—Petrochemical and Other Processed Petroleum Refineries

§ 98.250 Definition of source category.

(a) A petrochemical 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;
§ 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\textsubscript{2}, CH\textsubscript{4}, and N\textsubscript{2}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\textsubscript{2} 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, except for 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\textsubscript{4} and N\textsubscript{2}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\textsubscript{2} emissions. (Use the default CH\textsubscript{4} and N\textsubscript{2}O emission factors for “Petroleum (All fuel types in Table C–1)” 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, 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\textsubscript{2}, CH\textsubscript{4}, and N\textsubscript{2}O coke burn-off emissions from each catalytic cracking unit, fluid coking unit, and catalytic reforming unit under this subpart.

(c) CO\textsubscript{2} 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\textsubscript{2} process emissions from each on-site sulfur recovery plant under this subpart.

(e) CO\textsubscript{2}, CH\textsubscript{4}, and N\textsubscript{2}O emissions from each coke calcining unit under this subpart.

(f) CO\textsubscript{2} and CH\textsubscript{4} emissions from asphalt blowing operations under this subpart.

(g) CH\textsubscript{4} emissions from equipment leaks, storage tanks, loading operations, delayed coking units, and uncontrolled blowdown systems under this subpart.

(h) CO\textsubscript{2}, CH\textsubscript{4}, and N\textsubscript{2}O emissions from each process vent not specifically included in paragraphs (a) through (g) of this section under this subpart.

(i) CO\textsubscript{2} emissions from non-merchant hydrogen production process units (not including hydrogen produced from

and non-merchant hydrogen plants (i.e., hydrogen plants that are owned or under the direct control of the refinery owner and operator).