Petroleum Refineries Monitoring Checklist

Final Rule: Mandatory Reporting of Greenhouse Gases

United States Environmental Protection Agency

What Must Be Monitored if not Using a CEMS?

For flares, measure these parameters …

Carbon dioxide emissions

If you monitor carbon content at least weekly:

- ☐ Volume of flare gas combusted during measurement period (daily or weekly) (standard cubic feet (scf)/period)
- ☐ Average molecular weight of flare gas combusted during measurement period (daily or weekly) (kilogram (kg)/kilogram-mole)
- ☐ Average carbon content of flare gas combusted during measurement period (daily or weekly) (kg C/kg flare gas)

Or:

- ☐ Volume of flare gas combusted during measurement period (daily or weekly) (scf/period)
- ☐ Mole percent CO_2 concentration in the flare gas stream during the measurement period (mole percent = percent by volume)
- ☐ Mole percent concentration of compound "x" in the flare gas stream during the measurement period (mole percent = percent by volume)

If you monitor heat content at least weekly:

- ☐ Volume of flare gas combusted during measurement period (daily or weekly) (million (MM) scf/period)
- ☐ Higher heating value (HHV) for flare gas during measurement period (daily or weekly) (British thermal units (Btu/scf = mmBtu/MMscf)

If you do not measure the higher heating value or carbon content of the flare gas at least weekly:

- ☐ Annual volume of flare gas combusted during normal operations from company records (MMscf/year)
- ☐ HHV for fuel gas or flare gas from company records (Btu/scf = mmBtu/MMscf)
- ☐ Number of start-up, shutdown, and malfunction events during the year exceeding 500,000 scf/day
- ☐ Volume of flare gas combusted during indexed start-up, shutdown, or malfunction event (scf/event)
- ☐ Average molecular weight of the flare gas during indexed start-up, shutdown, or malfunction event (kg/kg-mole)
- ☐ Average carbon content of flare gas combusted during indexed start-up, shutdown, or malfunction event (kg C/kg flare gas)

Methane emissions

- ☐ Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from measurement values or engineering calculations (kg C in methane in flare gas/kg C in flare gas) (default is 0.4)

For catalytic cracking units and traditional fluid coking units with rated capacities greater than 10,000 barrels per stream day, measure these parameters…

Carbon dioxide emissions

- ☐ Hourly average percent CO_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis)
- ☐ Hourly average percent CO concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis)

You must also determine the hourly average exhaust gas flow rate from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels by monitoring:

- ☐ Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dry scfh)

Or:

- ☐ Volumetric flow rate of air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh)
- ☐ Volumetric flow rate of oxygen enriched air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh)
- ☐ Oxygen concentration in oxygen enriched gas stream inlet to the fluid catalytic cracking unit regenerator or fluid coking unit burner based on oxygen purity specifications of the oxygen supply used for enrichment (percent by volume—dry basis)

Or:

- ☐ Volumetric flow rate of air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh)
- ☐ Volumetric flow rate of oxygen enriched air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh)

- ☐ Hourly average percent oxygen concentration in exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis)
- ☐ Hourly average percent CO_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis)
- ☐ Hourly average percent CO concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis)
- ☐ Nitrogen (N_2) concentration in oxygen enriched gas stream inlet to the fluid catalytic cracking unit regenerator or fluid coking unit burner based on measured value or maximum N_2 impurity specifications of the oxygen supply used for enrichment (percent by volume – dry basis)
- ☐ Hourly average percent N_2 concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis)

Methane and nitrous oxide emissions

Calculate emissions using either unit specific measurement data, a unit specific emission factor based on a source test of the unit, or default values provided in the rule.

For catalytic cracking units and traditional fluid coking units with rated capacities of 10,000 barrels per stream day or less (if you do not continuously or no less frequently than daily monitor the O_2, CO_2, and, if necessary, CO concentrations in the exhaust stack), measure these parameters…

Carbon dioxide emissions

- ☐ Annual throughput of unit from company records (barrels/yr)
- ☐ Carbon content of coke based on measurement or engineering estimate (kg C/kg coke) (default = 0.94)

Methane and nitrous oxide emissions

Calculate emissions using either unit specific measurement data, a unit specific emission factor based on a source test of the unit, or default values provided in the rule.

For fluid coking units that use flexicoking design, measure these parameters…

Use methods described in 40 CFR 98, subpart C (General Stationary Combustion Sources) or monitor same parameters for traditional fluid coking units.

For catalytic reforming units, if you continuously or no less frequently than daily monitor 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, calculate emissions following the requirements of catalytic cracking units with rated capacities greater than 10,000 barrels per stream day; otherwise, measure these parameters…

Carbon dioxide emissions

- ☐ Coke burn-off quantity per regeneration cycle from engineering estimates (kg coke/cycle)
- ☐ Carbon content of coke based on measurement or engineering estimate (kg C/kg coke); default = 0.94
- ☐ Number of regeneration cycles in year

Methane and nitrous oxide emissions

Calculate emissions using either unit specific measurement data, a unit specific emission factor based on a source test of the unit, or default values provided in the rule.

For onsite sulfur recovery plants and for sour gas sent off site for sulfur recovery, measure these parameters…

Carbon dioxide emissions

- ☐ Volumetric flow rate of sour gas feed (including sour water stripper gas) to the sulfur recovery plant, from measurement if available, engineering calculations, or company records (scf/year)
- ☐ Mole fraction of carbon in the sour gas to the sulfur recovery plant, from measurement if available or engineering calculations (kg-mole C/kg-mole gas); default = 0.20

Non-Claus sulfur recovery units may alternatively elect to monitor:

- ☐ Number of venting events per year
- ☐ Venting time for the event (hours)
- ☐ Average volumetric flow rate of process gas during the event (scf/hour) [or this may me be determined from process knowledge or engineering estimates]
- ☐ Mole fraction of CO_2 in process vent during the event (kg-mol GHG/kg-mol vent gas) [or this may me be determined from process knowledge or engineering estimates]

For coke calcining units, measure these parameters…

Carbon dioxide emissions

- ☐ Annual mass of green coke fed to the coke calcining unit from facility records (metric tons/year)
- ☐ Annual mass of petroleum coke dust collected in the dust collection system of the coke calcining unit from facility records (metric ton petroleum coke dust/year)
- ☐ Average mass fraction carbon content of green coke from facility measurement data (metric ton C/metric ton green coke)
- ☐ Average mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (metric ton C/metric ton petroleum coke)
- ☐ Annual mass of marketable petroleum coke produced by coke calcining unit from facility records (metric tons petroleum coke/year)

For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, measure these parameters…

Carbon dioxide emissions

- ☐ Annual quantity of asphalt blown (MMbbl/year)
- ☐ Emission factor for CO_2 from uncontrolled asphalt blowing from facility-specific test data (metric tons CO_2/MMbbl asphalt blown); default = 1,100.

Methane emissions

- ☐ Annual quantity of asphalt blown (MMbbl/year)
- ☐ Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (metric tons CH_4/MMbbl asphalt blown); default = 580

For controlled asphalt blowing operations, measure these parameters…

Carbon dioxide emissions

- ☐ Annual quantity of asphalt blown (MMbbl/year)
- ☐ Carbon emission factor from asphalt blowing from facility-specific test data (metric tons C/MMbbl asphalt blown); default = 2,750
- ☐ Emission factor for CO_2 from uncontrolled asphalt blowing from facility-specific test data (metric tons CO_2/MMbbl asphalt blown); default = 1,100

Methane emissions

- ☐ Annual quantity of asphalt blown (MMbbl/year)
- ☐ Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (metric tons CH_4/MMbbl asphalt blown); default = 580

For delayed coking units, measure these parameters…

Methane emissions

- ☐ Total number of vessel openings for all delayed coking unit vessels of the same dimensions during the year
- ☐ Volumetric void fraction of coking vessel prior to steaming (cf gas/cf of vessel); default = 0.6
- ☐ Height of coking unit vessel (feet)
- ☐ Diameter of coking unit vessel (feet)
- ☐ Gauge pressure of the coking vessel when opened to the atmosphere prior to coke cutting, or the gauge pressure of the coking vessel when depressurization gases are first routed to the atmosphere (psig)
- ☐ Mole fraction of methane in coking vessel gas (kg-mole CH_4/kg-mole gas); default = 0.01

For other process vents that exceed the volume percent thresholds provided in the rule, measure these parameters…

For each Greenhouse Gas

- ☐ Number of venting events per year
- ☐ Venting time for the event (hours)
- ☐ Average volumetric flow rate of process gas during the event (scf/hour) [or this may me be determined from process knowledge or engineering estimates]
- ☐ Mole fraction of each GHG in process vent during the event (kg-mol GHG/kg-mol vent gas) [or this may me be determined from process knowledge or engineering estimates]

For uncontrolled blowdown systems, measure these parameters…

The same methods (and thus same parameters measured) to estimate emissions as "Other process vents" can be used. Alternatively the following parameters can be measured to calculate emissions in conjunction with other emission/conversion factors:

- ☐ Annual quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year)
- ☐ Methane emission factor for uncontrolled blown systems (scf CH_4/MMbbl); default = 137,000

For equipment leaks, measure these parameters…

Process-specific CH_4 composition data (from measurement data or process knowledge) and any of the emission estimation procedures provided in the Protocol for Equipment Leak Emissions Estimates (EPA-453/R-95-017, NTIS PB96-175401), or estimate emissions by measuring the following…

- ☐ Number of atmospheric crude oil distillation columns at the facility
- ☐ Cumulative number of catalytic cracking units, coking units (delayed or fluid), hydrocracking, and full-range distillation columns (including depropanizer and debutanizer distillation columns) at the facility
- ☐ Cumulative number of hydrotreating/hydrorefining units, catalytic reforming units, and visbreaking units at the facility
- ☐ Number of hydrogen plants at the facility
- ☐ Number of fuel gas systems at the facility

For storage tanks (other than those processing unstabilized crude oil) that have a vapor-phase methane concentration of 0.5 volume percent or more, measure these parameters…

Tank-specific CH_4 composition data (from measurement data or product knowledge) and the AP-42 emission estimation methods provided in Section 7.1 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Areas Sources", including the TANKS Model (Version 4.09D) or similar programs, or estimate emissions by measuring the following in conjunction with emission factor…

- ☐ Annual quantity of crude oil plus the quantity of intermediate products received from offsite that are processed at the facility (MMbbl/year)

For storage tanks that process unstabilized crude oil, measure these parameters…

Tank-specific CH_4 composition data (from measurement data or product knowledge) and direct measurement of the gas generation rate, or estimate emissions by measuring the following …

- ☐ Annual quantity of unstabilized crude oil received at the facility (MMbbl/year)
- ☐ Pressure differential from the previous storage pressure to atmospheric pressure (psi)
- ☐ Mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-mole CH_4/kg-mole gas); default = 0.27 if measurement data are not available

For crude oil, intermediate, or product loading operations for which the equilibrium vapor-phase concentration of CH_4 is 0.5 volume percent or more, measure these parameters…

- ☐ Product–specific, vapor-phase CH_4 composition data (from measurement data or process knowledge) and the emission estimation procedures provided in Section 5.2 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources"

What Must Be Monitored if Using a CEMS?

For catalytic cracking units or fluid coking units, in addition to the Tier 4 Calculation Methodology and associated requirements specified in 40 CFR 98, subpart C (General Stationary Fuel Combustion Sources), monitor these parameters if applicable…

- ☐ Fuel use in the CO boiler or other post-unit combustion device

For sulfur recovery plants, in addition to the Tier 4 Calculation Methodology and associated requirements specified in 40 CFR 98, subpart C (General Stationary Fuel Combustion Sources), monitor these parameters…

- ☐ Fuel use in the Claus burner, tail gas incinerator, or other combustion sources that discharge via the final exhaust stack from the sulfur recovery plant

For coke calcining units, in addition to the Tier 4 Calculation Methodology and associated requirements specified in 40 CFR 98, subpart C (General Stationary Fuel Combustion Sources), monitor these parameters…

- ☐ Fuel use in the coke calcining unit that discharges via the final exhaust stack from the coke calcining unit

See also the information sheet for Petroleum Refineries at:
www.epa.gov/ghgreporting/documents/pdf/infosheets/PetroleumRefineries.pdf.

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