Express Terms
Part 253 Mandatory Greenhouse Gas Reporting Program

Subpart 253-1 General Provisions

253-1.1 Purpose

The purpose of this Part is to establish a mandatory greenhouse gas (GHG) reporting program to provide information about GHG emissions from GHG emission sources.

253-1.2 Applicability

(a) This Part applies to greenhouse gases from GHG emission sources as set forth in this section.

(b) Reporting Categories. This Part applies to GHG emission sources, specifically the following persons that meet or exceed the thresholds established under subdivision (c) of this section. GHG emission sources may fall into multiple reporting entity categories.

(1) Owners and Operators of Facilities. The owner and operator of a facility within New York.

(2) Fuel suppliers.

(i) Suppliers of Natural Gas.

(ii) Suppliers of Liquid Fuels and Petroleum Products.

(iii) Suppliers of Liquefied Natural Gas and Compressed Natural Gas.

(iv) Suppliers of Coal.

(3) Waste Haulers and Transporters.

(4) Electric Power Entities.

(5) Suppliers of Agricultural Lime and Fertilizer.

(6) Anaerobic Digestion and Liquid Storage of Waste.

(c) Applicability Thresholds. The following applicability thresholds apply for Reporting

Entities:

(1) If a GHG emission source's annual emissions or activity in any emissions year from 2023 through 2025 meets or exceeds the thresholds identified in paragraph (3) of this subdivision, that person is a reporting entity as of January 1, 2026, and for all future years until the requirements for cessation set forth in subdivisions (n) or (o) of this section are met.

(2) If a GHG emission source's annual emissions or activity in any emissions year after January 1, 2026, meets or exceeds the thresholds identified below, that person is a reporting entity for that year and for all future years until the requirements for cessation set forth in subdivisions (n) or (o) of this section are met.

(3) The applicability threshold for each type of GHG emission source identified in this subdivision shall apply for emissions or activity categories as specified following the emission years set forth in paragraph (1) or (2) of this subdivision as follows:

(i) Owners and Operators of Facilities. The applicability threshold for owners and operators of facilities is 10,000 metric tons or more of CO_2e emissions per year, or a facility with budget unit(s) pursuant to Part 242 of this Title.

(ii) Fuel suppliers.

('a') Suppliers of Natural Gas. The applicability threshold for suppliers of natural gas is the cubic feet of natural gas necessary to generate any GHG emissions per emission year.

('b') Suppliers of Liquid Fuels and Petroleum Products. The applicability threshold for suppliers of liquid fuels and petroleum products is the gallons of affected liquid fuel necessary to generate any GHG emissions per emission year.

('c') Suppliers of Liquefied Natural Gas and Compressed Natural Gas. The applicability threshold for suppliers of liquefied natural gas and compressed natural gas is the cubic feet of liquified natural gas and/or compressed natural gas to generate any GHG emissions per emission year.

('d') Suppliers of Coal. The applicability threshold for suppliers of coal is the tonnage of coal necessary to generate any GHG emissions per emission year.

(iii) Waste haulers and transporters. The applicability threshold for waste haulers and transporters is as described in section 2.19 of this Part.

(iv) Electric power entities. The applicability threshold for electric power entities is any GHG emissions or imported Mwh.

(v) Suppliers of Agricultural Lime and Fertilizer. The applicability threshold for Suppliers of Agricultural Lime and Fertilizer is the quantity of agricultural lime and fertilizer necessary to generate any GHG emissions per emission year.

(vi) Anaerobic Digestion and Liquid Storage of Waste. The applicability threshold for facilities reporting emissions from anaerobic digesters or liquid storage of waste is as described in section 2.2 of this Part.

(d) Emissions Reported by Category. Persons that own or operate GHG emission sources that fall into the categories listed in subdivision (b) of this section, and meet the threshold listed in subdivision (c) of this section shall report as provided below:

(1) Facilities operators shall report emissions separately for each facility, and the applicability threshold shall apply to each facility separately.

(2) Fuel suppliers shall report emissions for all types of fuels that are owned in New York. A fuel supplier for multiple categories of fuel (liquid, gas, coal, LNG, or CNG) shall report annual emissions for these categories separately in one emissions report.

(3) Electric power entities shall report emissions separately for each facility or for each importer or exporter of electricity or retail provider.

(4) The applicability threshold for a waste transporter shall apply to the sum of emissions from all waste transported out of State by this person's waste transporters. The applicability thresholds apply to the person's emissions from all waste transporters operated by that person.

(e) Emissions Data Report. Any GHG emission source meeting the criteria in subdivisions (b) and (c) of this section must submit an annual emissions data report, except as provided in the cessation provisions of subdivisions (n) and (o) of this section. An emission source submitting annual data reports shall be known as a reporting entity. The emissions data report must cover all source categories and GHGs for which calculation methods are provided or referenced in this Part for the reporting source. Except as otherwise specified in this Part, the report must be compiled using the methods specified by source category in 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title).

(1) The department may request information from emission sources not identified in this Part to ascertain compliance or noncompliance with this Part.

(2) Emission sources reporting after January 1, 2026, under 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) shall notify the

department under which subpart of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) they are reporting and provide the department with the emissions reported if those emissions are not otherwise reported pursuant to this Part.

(3) The department is authorized to access any real property at which an emission source exists during normal business hours (7 a.m. to 7 p.m. Monday through Friday). Department representatives may inspect the real property unaccompanied by property representatives. Department representatives may traverse the property, inspect facilities, take measurements, analyze physical site characteristics, take environmental samples, sketch and photograph the property, and conduct other activities necessary to evaluate emissions and compliance with applicable statutory or regulatory requirements. The department may make reasonable efforts to share with the property owner or operator data collected during any access of real property. Establishment of a reporting account pursuant to section 1.6 of this Part may be considered written permission from the owner(s) of the real property on which an emission source is located for the department to access such property.

(f) Large Emission Sources. Emission sources meeting the thresholds identified in paragraphs (1) through (3) of this subdivision are considered large emission sources.

(1) Owners and Operators of Facilities. The applicability threshold for owners and operators of facilities is 25,000 metric tons or more of CO_2e per emissions year.

(2) Fuel suppliers.

(i) Suppliers of Natural Gas. The applicability threshold for suppliers of natural gas is 15,000,000 cubic feet or more of natural gas per emission year.

(ii) Suppliers of Liquid Fuels and Petroleum Products. The applicability threshold for suppliers of liquid fuels and petroleum products is 100,000 gallons or more of affected liquid fuels per emission year.

(iii) Suppliers of Liquefied Natural Gas and Compressed Natural Gas. The applicability threshold for suppliers of liquefied natural gas and compressed natural gas is 15,000,000 cubic feet or more of liquefied natural gas and/or compressed natural gas per emission year.

(iv) Suppliers of Coal. The applicability threshold for suppliers of coal is 500 U.S. short tons of coal per emission year.

(3) Waste Haulers and Transporters. The applicability threshold for waste haulers and transporters is 25,000 metric tons CO_2e per emission year. This applies to the sum of emissions reported for out-of-state landfill facilities and out of state combustion facilities for all of the waste exported out of New York by a waste transporter or a person operating multiple waste transporters.

(g) Calculating Facility GHG Emissions Relative to Thresholds. For emission sources specified in subdivision (b) of this section, the owner and operator must calculate, and report emissions as directed in section 1.4 and Subpart 2 of this Part.

(h) Hydrogen Fuel Cells. Operators of a hydrogen fuel cell unit must include emissions from the hydrogen fuel cell unit in calculating emissions for comparison to applicability thresholds.

(i) Fuel Suppliers. Liquid and gaseous fuel suppliers listed in this subdivision, as defined pursuant to this Part, are required to report under this Part when they own and distribute for sale any affected liquid or gaseous fuel in any quantity;

(1) position holders at terminals owning affected liquid fuels, as described in section 2.16 of this Part;

(2) enterers that own affected liquid fuels as described in section 2.16 of this Part;

(3) downstream owners, including below-the-rack distributors, of affected liquid fuels have reporting requirements pursuant to section 2.16 of this Part;

(4) owners of LPG that have reporting requirements pursuant to sections 2.16 and 2.17 of this Part;

(5) Energy Service Companies who provide gaseous fuels to end users in New York, as described in section 2.17 of this Part;

(6) operators of interstate pipelines delivering gaseous fuels, as described in section 2.17 of this Part;

(7) importers of compressed natural gas or liquefied natural gas into New York, as described in section 2.17 of this Part;

(8) local distribution companies who are public utility gas corporations or publicly-owned natural gas utilities delivering gaseous fuels, as described in section 2.17 of this Part;

(9) operators of intrastate pipelines delivering gaseous fuels as described in section 2.17 of this Part;

(10) all natural gas liquid fractionators, without regard to quantities produced, as described in section 2.17 of this Part;

(11) facilities that make liquefied natural gas products or compressed natural gas products by liquefying or compressing natural gas received from interstate pipelines, as described in section 2.17 of this Part.

(j) Electric Power Entities. The entities listed below are required to report under this Part:

(1) electricity importers and exporters, as defined pursuant to this Part;

(2) retail providers as defined pursuant to this Part.

(k) Petroleum and Natural Gas Systems. The facility types listed in this subdivision, as further specified in section 2.12 of this Part, are required to report emissions from stationary combustion, upstream out of state, fugitive, process, and vented:

(1) onshore petroleum and natural gas production facilities;

(2) onshore natural gas processing plants;

(3) onshore natural gas transmission compression facilities;

(4) onshore natural gas transmission pipelines;

(5) underground natural gas storage facilities;

(6) liquefied natural gas storage facilities;

(7) liquefied natural gas import and export facilities; and

(8) natural gas distribution facilities.

(l) Exemptions.

(1) GHG emissions reporting is not required for:

(i) fire suppression systems and equipment;

(ii) portable equipment at a facility when the fuel used in the equipment has been purchased at a retail location;

(iii) retailers of fuel unless the retailer is otherwise a facility or fuel supplier.

(2) Verification under this Part does not apply to the following:

(i) GHG emissions and facilities regulated pursuant to Part 242 of this Title.

(ii) GHG emissions associated with the fuel supplied by a fuel supplier to facilities regulated pursuant to Part 242 of this Title.

(iii) This exemption from verification does not apply to CO_2 budget units that have received a limited exemption pursuant to section 242-1.4(b) or (c) of this Title and whose primary NAICS code is not electricity generation. The primary NAICS code will be based on the one that most accurately describes the person's primary activity for its principal source of revenue, at the six-digit NAICS code level. The determination of which NAICS codes apply for the purposes of this subparagraph will be made by the department.

(iv) Owners and Operators of facilities in which the floor area dedicated to residential use accounts for 60 percent or more of its total floor area are exempted from the verification requirements under this Part if they submit to the department a certification that shall include:

('a') the total floor area of all buildings and structures associated with the facility, the uses of the facility, and the floor area associated with each use; and

('b') an attestation as follows: "I certify under penalty under the laws of the State of New York that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. I certify under penalty under the laws of the State of New York that the statement of information submitted to the department is true, accurate, and complete."

(v) N_2O emissions associated with the reporting requirements under section 2.2 of this Part. This exemption does not apply to N_2O emissions from the utilization of fuels at such reporting facilities.

(vi) GHG emissions associated with the reporting requirements for electric power entities under section 2.4 of this Part.

(vii) GHG emissions associated with the reporting requirements under subdivision 2.21(b) of this Part.

(m) Demonstration of Non-applicability. The department may request a demonstration from the owners and operators of an emission source that the emission source does not meet one or more of the applicability criteria specified in this Part. Such demonstration must be provided to the department within 30 days of receipt of a written request.

(n) Cessation of Reporting and Verification for Reduced Emissions. The requirements for the owners and operators of emission sources whose emissions are reduced below applicable reporting and verification thresholds are as follows for ceasing reporting and verification.

(1) Reporting for Large Emission Sources.

(i) Large emission sources pursuant to subdivision (f) of this section, must report and verify emissions until they are less than the thresholds specified in subdivision (f) of this section for three consecutive years, except as specified in this subparagraph. If annual emissions for an emission source exceed the thresholds specified in subdivision (f) of this section in any year after cessation requirements have been met, then the emission source is a large emission source and must resume verification as required pursuant to this Part.

('a') If an emission source's emissions drop below the threshold specified in subdivision (f) of this section in meeting the requirements for cessation in subparagraph (i) of this paragraph, but the emission source's total emissions remain above the threshold specified in subdivision (c) of this section, the emission source must continue to report under this Part until emissions drop below the threshold specified in subdivision (c) of this section for three consecutive years, and in this case the owner or operator of an emission source must meet the requirements in paragraph (2) of this subdivision to cease reporting under this Part.

('b') Fuel suppliers that cease to supply fuel in New York and whose emissions drop to zero for a consecutive three-year period. Pursuant to section 1.4(j)(2)(iv) of this Part, entities that cease to have a reporting obligation or qualify as a large emission source pursuant to subdivision (f) of this section as a fuel supplier due to a change in ownership or sale or relinquishment of an inventory position at a terminal must continue to report and verify emissions from the reportable fuel transactions that occurred prior to the change. Fuel suppliers that cease to supply fuel in New York and no longer have any reportable emissions must verify their emissions data report in the first year in which they report zero emissions. Any reporting year thereafter with zero reportable emissions is not subject to verification.

(ii) An emission source that meets the cessation requirements for reporting, and verification if applicable, pursuant to subparagraph (i) of this paragraph must notify the department in writing that it is ceasing to report, and ceasing to verify if applicable, pursuant to this Part and provide the reason(s) for the reduction of emissions. The notification must be submitted no later than the applicable reporting deadline for the year following the last emission year that the emission source is required to submit an emissions data report. Emission sources must provide the cessation notification to the address indicated in section 1.4(k) of this Part.

(2) Reporting Entities that are not Large Emission Sources.

(i) Facility operators and suppliers. The owners and operators of emission sources whose total reported emissions are below the reporting thresholds specified in subdivision (c) of this section in each reporting year must report under this Part until emissions are less than the reporting thresholds for three consecutive years. If total reported emissions for an emission source exceeds the reporting thresholds in any year after cessation requirements have been met, the owner or operator must resume reporting as required under this Part.

('a') Emission sources that have total reported emissions or fuel throughputs that exceed the thresholds in subdivision (f) of this section in a reporting year must have their emissions data report verified for three consecutive years, are a large emission source, and must follow cessation requirements in paragraph (1) of this subdivision.

('b') If in meeting the cessation requirements in this subparagraph a fuel supplier ceases to supply fuel in New York and emissions drop to zero, the person must continue to report until emissions are zero for a consecutive three-year period. Pursuant to section 1.4(j)(2)(iv) of this Part, entities that cease to have a reporting obligation as a fuel supplier due to a change in ownership or sale or relinquishment of an inventory position at a terminal must continue to report and verify emissions from the reportable fuel transactions that occurred prior to the change.

(ii) Electric power entities that import or export electricity from New York must report until there are zero imports or exports to report for a consecutive three-year period.

(iii) An emission source that meets the cessation requirements for reporting, and verification if applicable, pursuant to subparagraphs (i) and (ii) of this paragraph must notify the department in writing that it is ceasing to report, or verify if applicable, pursuant to this Part and provide the reason(s) for cessation of reporting, or verification if applicable. The notification must be submitted no later than the applicable reporting deadline for the year following the last emission year that the emission source is required to submit an emissions data report. Emission sources must provide the cessation notification to the address indicated in section 1.4(k) of this Part.

(iv) Owners and operators of emission sources that fully exit reporting pursuant to this paragraph must maintain the corresponding records required under section 1.7 of this Part and retain such records for five years following the submission of the final emissions data report to the department.

(o) Cessation of Reporting and Verification for Shutdown Facilities. The requirements for owners and operators of an emission source that cease to operate or permanently shut down as defined in this subdivision are as follows for ceasing reporting and verification.

(1) If the operations of an emission source are changed such that all applicable GHG-emitting processes and operations cease to operate or are permanently shut down, the owner or operator must submit an emissions data report for the year in which the facility's GHG-emitting processes and operations ceased to operate, and for the three years of non-operation that follow. The owner or operator must submit a notification to the department that announces the cessation of reporting and certifies to the cessation of all GHG-emitting processes and operations no later than the reporting deadline of the year following the cessation of operations or permanent shutdown.

(2) For the purposes of this provision, "cease to operate" means the facility did not operate any GHG-emitting processes for an entire calendar year. Continued operation of space heaters and water heaters as necessary until operations are restarted in a subsequent year does not preclude a facility from meeting the definition of "cease to operate" provided that the reporting entity's emissions from the space heaters and water heaters are below the applicable threshold pursuant to this section. If the emissions from the operation of space heaters and water heaters is greater than the reporting threshold pursuant to this section, the facility is subject to the reporting requirements of this Part. The owner or operator must resume reporting for any future calendar year during which any of the GHG-emitting processes or operations resume operation and are subject to reporting.

(3) For the purposes of this paragraph, permanently "shut down" means the emission source has objective evidence that operations are permanently shut down, including but not limited to, decommissioning, and cancelling air permits or other operating

permits. For this provision, permanent shutdown may include continued operation of space heaters and water heaters as necessary to support decommissioning activities. If the emissions from the operation of space heaters and or water heaters is greater than the applicable reporting threshold pursuant to this section, the facility is subject to the reporting requirements of this Part.

(4) Paragraph (1) of this subdivision does not apply to seasonal or other temporary cessation of operations.

(5) The owner or operator of an emission source must resume reporting for any future calendar year during which any of the GHG-emitting processes or operations resume operation and are subject to reporting.

(p) Emission Factor Adjustments. For reporting year 2031 and beyond, Reporting Entities shall use the updated emission factors specified by the department as published on the department website and used within the reporting mechanism pursuant to section 1.6 of this Part.

(1) Six months before the start of the 2031 reporting year and six months before the start of any reporting year thereafter, the department will issue a report updating the emission factors for use in this Part. The department will publicly post the report and invite public comment for 30 calendar days from the date the report is posted. The report will include:

(i) for the first report, previously reported emissions and activity data submitted under this Part and from other reliable sources will be compared to the existing emission factors and the methodologies used to establish those factors. For each subsequent report, emissions and activity data reported in the previous three years under this Part and from other reliable sources will be compared to established emission factors and methodologies;

(ii) the reports will highlight the difference in emission factors and data trends from the start of the reporting program up to the most recently issued report.

253-1.3 Definitions

(a) To the extent that they are not inconsistent with the specific definitions in subdivision (b) of this section, the general definitions in Part 200 of this Title and 40 CFR § 98.6 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) apply to this Part.

(b) General Definitions.

For the purposes of this Part, the following specific definitions apply:

(1) 'Absorbent Circulation Pump'. A pump commonly powered by natural pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

(2) 'Accuracy'. The closeness of the agreement between the result of the measurement and the true value of the particular quantity (or a reference value determined empirically using internationally accepted and traceable calibration materials and standard methods), taking into account both random and systematic factors.

(3) 'Acid Gas'. Hydrogen sulfide (H2S) and/or carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal.

(4) ‘Acid Gas Removal Unit (AGR)’. A process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators.

(5) ‘Adverse Emissions Data Verification Statement’. A verification statement rendered by a verification body attesting that the verification body cannot say with reasonable assurance that the submitted emissions data report is free of material misstatement, or that the emissions data submitted in the emissions data report contains correctable errors as defined pursuant to this section and thus is not in conformance with the requirement to fix such errors pursuant to section 4.2(b)(8) of this Part, or both.

(6) ‘Adverse Product Data Verification Statement’. A verification statement rendered by a verification body attesting that the verification body cannot say with reasonable assurance that the submitted emissions data report is free of material misstatement, or that the industrial product data submitted in the emissions data report contains correctable errors as defined pursuant to this section and thus is not in conformance with the requirements to fix such errors pursuant to section 4.2(b)(8) of this Part, or both.

(7) ‘Adverse Verification Statement’. An adverse emissions data verification statement or adverse product data verification statement.

(8) ‘Affected Liquid Fuels’. Liquid fuels or petroleum products owned in New York and destined for, or resulting in, final sale in New York.

(9) ‘Agricultural Liming Material’. All materials and all calcium and magnesium products in the oxide, hydrate, carbonate or silicate form or combinations thereof and intended for use in the correction of soil acidity, including such forms of material designated

as burned lime, hydrated lime, carbonate of lime, agricultural limestone, slag, and marl.

(10) ‘Agricultural Waste’. Manure, crop residue, animal carcasses, and other similar waste that is generated on a farm.

(11) ‘Aluminum Alloy’. An alloy in which aluminum is the predominant metal and the alloying elements may typically be copper, magnesium, manganese, zinc, or other elemental additives or any combination of elements added.

(12) ‘Aluminum and Aluminum Alloy Billet’. A solid bar of nonferrous metal produced by casting molten aluminum alloys that is suitable for subsequent rolling, casting, or extrusion.

(13) ‘Anaerobic Digester’. The system where wastes are collected and anaerobically digested in large containment vessels or covered lagoons. Anaerobic digesters stabilize waste by the microbial reduction of complex organic compounds to CO_2 and CH_4, which is captured and may be flared or used as fuel. Anaerobic digestion systems include but are not limited to covered storages, complete mix, plug flow, and fixed film digesters.

(14) ‘Anaerobic Reactor’. An enclosed vessel used for anaerobic wastewater treatment (e.g., upflow anaerobic sludge blanket, fixed film).

(15) ‘Anaerobic Treatment’. The biochemical decomposition of organic matter primarily into stabilized solids, CH_4, and CO_2 by microorganisms in the absence of O_2. For purposes of section 2.2 of this Part, anaerobic treatment does not include depositing waste in landfills.

(16) ‘Annual’. With a frequency of once a year; unless otherwise noted, annual events such as reporting requirements will be based on the calendar year.

(17) ‘API’. The American Petroleum Institute or API.

(18) ‘API Gravity’. A scale used to reflect the specific gravity (SG) of a fluid such as crude oil, or water. The API gravity is calculated as [(141.5/SG) - 131.5], where SG is the specific gravity of the fluid at 60°F.

(19) ‘Asphalt’. The dark brown to black cementitious material (solid, semisolid or liquid in consistency) of which the main constituents are bitumens that occur naturally or as a residue of petroleum refining.

(20) ‘Asset-Controlling Supplier’. Any person that owns or operates inter-connected electricity generating facilities or serves as an exclusive marketer for these facilities even though it does not own them and is assigned a supplier-specific identification number and system emission factor by the department for the wholesale electricity procured from its system and imported into New York. Asset controlling suppliers are considered specified sources.

(21) ‘Assigned Emissions Level’. An amount of GHG emissions, in CO_2e, assigned to the reporting entity by the department under the requirements of section 4.2(c)(5) of this Part.

(22) ‘Associated Gas’. A natural gas that is produced in association with the production of crude oil.

(23) ‘ASTM’. The American Society of Testing and Materials.

(24) ‘Atomic Hydrogen Content’. The mass fraction of all hydrogen atoms in a gas, mixture of gases, or a mixture of other materials.

(25) ‘Aviation Gasoline’. A complex mixture of volatile hydrocarbons, with or

without additives, suitably blended to be used in aviation reciprocating engines. Specifications can be found in ASTM D910–24, “Standard Specification for Aviation Gasolines” (2024) (see Table 1, section 200.9 of this Title).

(26) ‘Balancing Authority’. The responsible person that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area and supports interconnection frequency in real time.

(27) ‘Balancing Authority Area’. The collection of generation, transmission, and loads within the metered boundaries of a balancing authority. A balancing authority maintains load-resource balance within this area.

(28) ‘Barrel’. A volume equal to 42 U.S. gallons.

(29) ‘Basin’. Geological provinces as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG-CSD Geological Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laurie G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) (see Table 1, section 200.9 of this Title).

(30) ‘Below-The-Rack Distributor’. An owner of affected liquid fuels at the time such fuel is delivered for final sale or to the end user in New York.

(31) ‘Best Available Data and Methods’. Methods described by the department for emissions calculations set forth in this Part where reasonably feasible, or facility fuel use and other facility process data used in conjunction with department provided emission factors and other data, or other industry standard methods for calculating GHG emissions.

(32) ‘Bias’. Systematic error resulting in measurements that will be either consistently low or high relative to the reference value.

(33) 'Bigeneration Unit'. A unit that simultaneously generates electricity and useful thermal energy from the same fuel source but without waste heat recovery. An example of bigeneration includes a boiler generating steam that is split into two streams, and one stream powers a steam turbine to generate electricity, while the other stream is used for other industrial, commercial, heating, and cooling purposes that are not in support of or a part of the electricity generation system.

(34) 'Biodiesel'. A diesel fuel substitute produced from nonpetroleum renewable resources that meet the registration requirements for fuels and fuel additives established by the U.S. Environmental Protection Agency under section 211 of the Clean Air Act (42 U.S.C. 7545) (January 3, 2024) (see Table 1, section 200.9 of this Title). It includes biodiesel that is all of the following:

(i) registered as a motor vehicle fuel or fuel additive under 40 CFR part 79 (July 1, 2024) (see Table 1, section 200.9 of this Title);

(ii) a mono-alkyl ester;

(iii) meets American Society for Testing and Material designation ASTM D6751- 24 “Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels” (2024) (see Table 1, section 200.9 of this Title);

(iv) intended for use in engines that are designated to run on conventional diesel fuel; and

(v) derived from non-petroleum renewable resources.

(35) 'Biogas'. The combination of CO_2, CH_4, and other gases produced by the biological breakdown of organic matter in the absence of oxygen. Gas that is produced from

the breakdown of organic material in the absence of oxygen. Biogas is produced in processes including anaerobic digestion, anaerobic decomposition, and thermochemical decomposition. These processes are applied to biodegradable biomass materials, such as manure, sewage, municipal solid waste, green waste, and waste from energy crops, to produce landfill gas, digester gas, and other forms of biogas.

(36) ‘Biomass’. Non-fossilized and biodegradable organic material originating from plants, animals and micro-organisms, including products, by-products, residues and waste from agriculture, forestry and related industries, as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material.

(37) ‘Biomass-Derived Fuels or Biomass Fuels or Biofuels or Biomass-Based Fuels’. Fuels derived from biomass; includes but is not limited to biodiesel and ethanol.

(38) ‘Biosolids’. the accumulated semi-solids or solids resulting from treatment of municipal or industrial wastewater. Biosolids do not include grit, fixed solids, or screenings or ash generated from the incineration of biosolids.

(39) ‘Blendstock’. Any liquid compound or mixture of compounds (not including fuel or fuel additive) that is used or intended for use as a component of a fuel.

(40) ‘Blowdown’. The act of emptying or depressurizing a vessel. This may also refer to the discarded material such as blowdown water from a boiler or cooling tower.

(41) ‘Boiler’. An enclosed fossil or other fuel-fired combustion device, or other heat source, used to produce heat and to transfer heat to recirculating water, steam or other

medium.

(42) ‘Bone Dry Short Ton’. An amount of material that weighs 2,000 pounds at zero percent moisture content.

(43) ‘Bottom Ash’. Ash that collects at the bottom of a combustion chamber.

(44) ‘Bottoming Cycle’. A type of cogeneration system in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for electricity production.

(45) ‘British Thermal Unit or Btu’. The quantity of heat required to raise the temperature of one pound of water by 1°F at about 39.2°F.

(46) ‘BTEX’. Gaseous compounds of benzene, toluene, ethyl benzene, and xylenes.

(47) ‘Bubble Point Pressure’. The pressure, at the pressurized sample collection temperature, at which the first bubble of gas comes out of solution.

(48) ‘Bulk Transfer/Terminal System’. A fuel distribution system consisting of refineries, pipelines, vessels, and terminals. Fuel storage and blending facilities that are not fed by pipeline or vessel are considered outside the bulk transfer system.

(49) ‘Busbar’. A power conduit of a facility with electricity generating units that serves as the starting point for the electricity transmission system.

(50) ‘Butane or n-Butane’. A paraffinic straight-chain hydrocarbon with molecular formula C_4H_{10}.

(51) ‘Butylene or n-Butylene’. An olefinic straight-chain hydrocarbon with

molecular formula C_4H_8.

(52) ‘Bypass Dust’. Discarded dust from the bypass system dedusting unit of suspension preheater, precalciner and grate preheater kilns, consisting of fully calcined kiln feed material.

(53) ‘Calcination’. The thermal decomposition of carbonate minerals, such as calcium carbonate (the principal mineral in limestone) to form calcium oxide in a cement kiln.

(54) ‘Calcine’. To heat a substance so that it oxidizes or reduces.

(55) ‘Calendar Year’. Refers to a period of time based upon a calendar year commencing January 1 and terminating midnight December 31.

(56) ‘Calibrated Bag’. A flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to an emitting source such that the emissions inflate the bag to its calibrated volume.

(57) ‘Carbon Dioxide or CO_2’. A GHG, consisting of a molecular level of a single carbon atom and two oxygen atoms.

(58) ‘Carbon Dioxide Equivalent or CO_2 Equivalent or CO_2e’. The amount of carbon dioxide by mass that would produce the same global warming impact as a given mass of another GHG over an integrated 20-year time frame after emission. CO_2e shall be calculated using the CO_2e values in section 496.5 of this Title. For values not listed in section 496.5 of this Title, CO_2e shall be calculated using GWP20 values consistent with the Intergovernmental Panel on Climate Change (IPCC) Assessment Report, Table 7.SM.7 from Smith, C., Z.R.J. Nicholls, K. Armour, W. Collins, P. Forster, M. Meinshausen, M.D. Palmer, and M. Watanabe, 2021: The Earth’s Energy Budget, Climate Feedbacks, and Climate

Sensitivity Supplementary Material. In Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change. Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.), pp 16-27 (see Table 1, section 200.9 of this Title).

(59) 'Carbonate'. Compounds containing the ion CO_3^{-2}. Upon calcination, the carbonate radical decomposes to evolve carbon dioxide (CO_2). Common carbonates consumed in the mineral industry include calcium carbonate ($CaCO_3$) or calcite; magnesium carbonate ($MgCO_3$) or magnesite; and calcium-magnesium carbonate ($CaMg(CO_3)_2$) or dolomite.

(60) 'Carbonate-Based Raw Material'. Any of the following materials used in the manufacture of glass: Limestone, dolomite, soda ash, barium carbonate, potassium carbonate, lithium carbonate, and strontium carbonate.

(61) 'Catalyst'. A substance added to a chemical reaction, which facilitates or causes the reaction, and is not consumed by the reaction.

(62) 'CBOB'. Conventional blendstock for oxygenate blending. A petroleum product that, when blended with a specified type and percentage of oxygenate, is motor gasoline that is not certified to meet the requirements for reformulated gasoline in regulations promulgated by the U.S. EPA under 40 CFR § 1090.220 (July 1, 2024) (see Table 1, section 200.9 of this Title).

(63) 'Cement'. A building material that is produced by heating mixtures of

limestone and other minerals or additives at high temperatures in a rotary kiln to form clinker, followed by cooling and grinding with blended additives. Finished cement is a powder used with water, sand and gravel to make concrete and mortar.

(64) 'Cement Kiln Dust or CKD'. The fine-grained, solid, highly alkaline waste removed from cement kiln exhaust gas by air pollution control devices. CKD consists of partly calcined kiln feed material and includes all dust from cement kilns and bypass systems including bottom ash and bypass dust.

(65) 'Centrifugal Compressor'. Any equipment that increases the pressure of a process natural gas or CO_2 by centrifugal action, employing rotating movement of the driven shaft.

(66) 'Centrifugal Compressor Dry Seals'. A series of rings around the compressor shaft where it exits the compressor case that operate mechanically under the opposing forces to prevent natural gas or CO_2 from escaping to the atmosphere.

(67) 'Certification or Certify'. Refers to the procedure in 40 CFR § 98.4(e) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), as required for reports submitted to the department under this Part.

(68) 'CFR'. Code of Federal Regulations

(69) 'Chain of Title'. The sequence of historical transfers of title to a fuel or product from the producer to the reporting entity, which may include bills of lading.

(70) 'City Gate'. Is a point or measuring where custody transfer occurs between a natural gas transmission system pipeline company/operator and a distribution system company/operator.

(71) 'Clinker'. The mass of fused material produced in a cement kiln from which finished cement is manufactured by milling and grinding.

(72) 'Coal'. All solid fuels classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388–23 "Standard Classification of Coals by Rank" (2023) (see Table 1, section 200.9 of this Title).

(73) 'Coal Supplier or Supplier of Coal'. A person producing, importing, supplying, distributing, or selling coal.

(74) 'Cogeneration'. An integrated system that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential or simultaneous use of the original fuel energy. Cogeneration must involve generation of electricity and useful thermal energy and some form of waste heat recovery. Some examples of cogeneration include: (i) a gas turbine or reciprocating engine generating electricity by combusting fuel, which then uses a heat recovery unit to capture useful heat from the exhaust stream of the turbine or engine; (ii) steam turbines generating electricity as a by-product of steam generation through a fired boiler; (iii) cogeneration systems in which the fuel input is first applied to a thermal process such as a furnace and at least some of the heat rejected from the process is then used for power production. For the purposes of this Part, a combined-cycle power generation unit, where none of the generated thermal energy is used for industrial, commercial, or heating and cooling purposes (these purposes exclude any thermal energy use that is either in support of or a part of the electricity generation system), is not considered a cogeneration unit.

(75) 'Cogeneration System'. Individual cogeneration components including the

prime mover (heat engine), generator, heat recovery, and electrical interconnection, configured into an integrated system that provides sequential or simultaneous generation of multiple forms of useful energy (usually mechanical and thermal), at least one form of which the facility consumes on-site or makes available to other users for an end-use other than electricity generation.

(76) ‘Cogeneration Unit’. A unit that produces electric energy as an electricity generating unit and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential or simultaneous use of the original fuel energy and waste heat recovery.

(77) ‘Combustion Emissions’. GHG emissions occurring during the exothermic reaction of a fuel with oxygen.

(78) ‘Combustion Source’. A source of emissions resulting from combustion.

(79) ‘Commercial Fertilizer’. Any substances containing one or more recognized plant nutrients which is used for its plant nutrient content, and which is designed for use or claimed to have value in promoting plant growth, except unmanipulated animal and vegetable manures, agricultural liming material, wood ashes, gypsum, and other products exempted by regulation of the commissioner.

(80) ‘Community Choice Aggregator’. A municipality or group of municipalities that acts as an aggregator and broker for the sale of energy and other services to residents.

(81) ‘Component’. For the purposes of section 2.12 of this Part, each metal-to-metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier

through which natural gas or liquid can escape to the atmosphere.

(82) ‘Composting and Other Organics Processing Facility’. A facility that treats the readily biodegradable organic components in waste to produce a mature product for use as a source of nutrients, organic matter, liming value, or other essential constituent for a soil or to help sustain plant growth. The processes include, but are not limited to, composting, vermiculture, anaerobic digestion, fermentation, and class A processes. An organics waste processing facility also includes processes to convert biodegradable organic components in food scraps into animal feed including pet food.

(83) ‘Compressed Natural Gas or CNG’. Natural gas in high-pressure containers that is highly compressed (though not to the point of liquefaction), typically to pressures ranging from 2900 to 3600 psi.

(84) ‘Compressor’. Any machine for raising the pressure of a natural gas or CO_2 by drawing in low pressure natural gas and discharging significantly higher-pressure natural gas or CO_2.

(85) ‘Condensate’. Liquid hydrocarbons that were originally in the gaseous phase in the reservoir and liquids recovered by surface separation from natural gas.

(86) ‘Conflict-of-interest’. A situation in which, because of financial or other activities or relationships with other persons, a person is unable or potentially unable to render an impartial verification statement of an existing or potential client’s GHG emissions data report, or the person’s objectivity in performing verification services is or might be otherwise compromised.

(87) ‘Construction and Demolition Debris or C&D Debris’. Means waste

resulting from construction, remodeling, repair and demolition of structures, buildings and roads. C&D debris includes fill material, demolition wastes, and construction wastes. Materials that are not C&D debris (even if generated from construction, remodeling, repair and demolition activities) include municipal solid waste, friable asbestos-containing waste, corrugated container board, electrical fixtures containing hazardous liquids such as fluorescent light ballasts or transformers, fluorescent lights, furniture, appliances, tires, drums, fuel tanks, containers greater than 10 gallons in size, and any containers having more than one inch of residue remaining on the bottom.

(88) ‘Continuous Bleed’. The continuous venting of natural gas from a gas actuated pneumatic device to the atmosphere by design.

(89) ‘Continuous Emissions Monitoring System or CEMS’. The total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.

(90) ‘Continuous Physical Transmission Path’. The full transmission path shown in the physical path table of a single NERC e-tag from the first point of receipt closest to the generation source to the final point of delivery closest to the final sink.

(91) ‘Corn’ The kernels of the dent corn plant (Zea mays var. indentata.) that have been shelled and contain no more than 10 percent of other grains.

(92) ‘Correctable Errors’. Errors identified by the verification team that affect emission source data or industrial product data in the submitted emissions data report that result from a nonconformance with this Part. Differences that, in the professional judgment of the verification team, are the result of differing but reasonable methods of truncation or

rounding or averaging, where a specific procedure is not prescribed by this Part, are not considered errors and therefore do not require correction.

(93) ‘Cracking’. The process of breaking down larger molecules into smaller molecules, using catalysts and/or elevated temperatures and pressures.

(94) ‘Crude Oil’. A mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Depending upon the characteristics of the crude stream, it may also include any of the following:

(i) small amounts of hydrocarbons that exist in gaseous phase in natural underground reservoirs but are liquid at atmospheric conditions (temperature and pressure) after being recovered from oil well (casing-head) gas in lease separators and are subsequently commingled with the crude stream without being separately measured. Lease condensate recovered as a liquid from natural gas wells in lease or field separation facilities and later mixed into the crude stream is also included;

(ii) small amounts of non-hydrocarbons, such as sulfur and various metals;

(iii) drip gases, and liquid hydrocarbons produced from tar sands, oil sands, gilsonite, and oil shale;

(iv) petroleum products that are received or produced at a refinery and subsequently injected into a crude supply or reservoir by the same refinery owner or operator; and

(v) liquids produced at natural gas processing plants and natural gas fractionating facilities are excluded, unless the produced natural gas liquids are extracted from produced gas, associated gas, and waste gas at a facility and re-injected into barrels of crude oil produced by the same facility.

(95) ‘Customer’. A purchaser of electricity not for the purposes of retransmission or resale.

(96) ‘Customer Meter’. The meter that measures the transfer of gas from an operator to a consumer, including the riser, and fittings at residential, commercial, or industrial premise(s).

(97) ‘Degradable Organic Carbon (DOC)’ the fraction of waste (kg C/kg-dry mass of waste) that can be biologically degraded. This may include but is not limited to volatile solids in animal manure, biosolids and sources of biological oxygen demand in municipal and industrial wastewater.

(98) ‘Dehydrator’. A device in which an absorbent (including desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

(99) ‘Dehydrator Vent Emissions’. Natural gas and CO_2 release from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator to the atmosphere or a flare, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

(100) ‘Delayed Coking’. A process by which heavier crude oil fractions are thermally decomposed under conditions of elevated temperature and pressure to produce a mixture of lighter oils and petroleum coke.

(101) 'Delivered Electricity'. Electricity that was distributed from a purchasing-selling entity (PSE) and received by a PSE or electricity that was generated, transmitted, and consumed.

(102) 'Desiccant'. A material used in dehydrators to remove water from raw natural gas by adsorption or absorption. Desiccants include activated alumina, palletized calcium chloride, lithium chloride and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelletized solid adsorbent or absorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface or absorbed and dissolves the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto or absorbed into the desiccant material, leaving the dry gas to exit the contactor.

(103) 'Designated Representative'. The person responsible for certifying, signing, and submitting the GHG emissions data report.

(104) 'Destruction Device'. Means a flare, thermal oxidizer, boiler, turbine, internal combustion engine, or any other CH_4 destroying unit.

(105) 'Diesel Fuel'. Distillate Fuel No. 1 and Distillate Fuel No. 2, including dyed and nontaxed fuels.

(106) 'Digestate'. The solid and liquid material removed from an anaerobic digester once it has undergone anaerobic treatment.

(107) 'Direct Delivery of Electricity or Directly Delivered'. Electricity that meets any of the following criteria:

(i) the facility has a first point of interconnection with transmission facilities within the NYCA;

(ii) the facility has a first point of interconnection with distribution facilities used to serve end users within NYCA;

(iii) the electricity is scheduled for delivery from the specified source to NYCA via a continuous physical transmission path from interconnection of the facility in the balancing authority in which the facility is located to a sink located in New York; or

(iv) there is a private agreement from the facility to a person within New York State.

(108) ‘Disburse’. With respect to a position holder, to cause the physical transfer of liquid fuels or petroleum products from a terminal at a rack.

(109) ‘Disbursed for final sale or to an end user in New York.’ Disburse affected liquid fuels as reflected in the records of the terminal operator on in the shipping documents issued at the time of disbursement. If in the records or shipping document the destination of the fuel or product is in New York, then the fuel or product shall be treated as disbursed for final sale or to an end user in New York and be an affected liquid fuel unless a subsequent shipping document for this fuel contains corrected destination for diversion or a subsequent fuel owner (below the rack distributor) reports this fuel as being diverted.

(110) ‘Distillate Fuel Oil’. A classification for one of the petroleum fractions produced in conventional distillation operations and from crackers and hydrotreating process units. The generic term “distillate fuel oil” includes kerosene, kerosene-type jet fuel, diesel fuels (Diesel Fuels No. 1, No. 2, and No. 4), and fuel oils (Fuel Oils No. 1, No. 2, and No. 4).

(111) ‘Distribution Pipeline’. A pipeline that is designated as such by the

Pipeline and Hazardous Material Safety Administration (PHMSA) in 49 CFR § 192.3 (October 1, 2023) (see Table 1, section 200.9 of this Title).

(112) ‘District Heating Facility’. A facility that, at a central plant, produces hot water, steam and/or chilled water that is distributed through underground pipes to buildings and facilities connected to the system that are not part of the same facility. District Heating Facility does not include a facility that produces electricity.

(113) ‘Diversion or Diverted’. An owner of affected liquid fuels changing the destination for final sale to a jurisdiction that is not New York.

(114) ‘Double Valve Cylinder’. Means a metal cylinder equipped with valves on either side for collecting crude oil, condensate, or produced water samples.

(115) ‘Dry Gas or Dry Natural Gas’. Natural gas which remains after:

(i) the liquefiable hydrocarbon portion has been removed from the gas stream (i.e., gas after lease, field, and/or plant separation); and

(ii) any volumes of nonhydrocarbon gases have been removed where they occur in sufficient quantity to render the gas unmarketable.

Dry natural gas is also known as consumer-grade natural gas. The parameters for measurement are cubic feet at 60°F and 14.73 pounds per square inch absolute.

(116) ‘Dry Mass’. Mass of material that has been dried at 105°C until reaching a constant mass or 100 percent solids content.

(117) ‘EIA’. The Energy Information Administration. The Energy Information Administration (EIA) is a statistical agency of the U.S. Department of Energy.

(118) ‘Electrical Distribution Utility(ies) or EDU’. A person that owns and/or

operates an electrical distribution system, including:

(i) a public utility corporation as defined in section 2 of the Public Service Law;

(ii) a public utility company owned or operated by a municipality as those terms are defined in section 2 of the Public Service Law; or

(iii) an Electrical Cooperative as defined as a Cooperative in section 2 of the Rural Electric Cooperative Law, that provides electricity to retail end users in New York.

(119) 'Electric Power Entity or EPE'. An electricity importer, electricity exporter or a retail provider.

(120) 'Electricity Exporter'. A person that delivers exported electricity. The person that exports electricity is identified on the NERC e-Tag as the PSE on the last segment of the tag's physical path, with the point of receipt located inside New York and the point of delivery located outside New York.

(121) 'Electricity Generating Facility'. A facility that generates electricity and includes one or more generating units at the same location.

(122) 'Electricity Generation Provider'. A provider of the energy or generation component of electricity services, as distinguished from the provider of transmission and/or distribution service that provides the wires for the transport of electricity. Electricity generation providers may include electricity service providers, community choice aggregators, cogeneration facilities, and other entities in addition to electrical distribution utilities that may provide both generation and transmission/distribution service.

(123) 'Electricity Generating Unit or EGU'. Any combination of physically

connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power. An EGU may include a unit that generates electricity from fuel combustion or from other renewable energy sources, such as solar and wind.

(124) 'Electricity Generation System'. A cogeneration system, a bigeneration system, a combined cycle electricity generation system, or a system with boilers and steam turbine generators.

(125) 'Electricity Importers'. A person that delivers imported electricity. For electricity that is scheduled with a NERC e-Tag to a final point of delivery inside New York, the electricity importer is identified on the NERC e-Tag as the PSE on the last segment of the tag's physical path with the point of receipt located outside New York and the point of delivery located inside New York. For facilities physically located outside New York with the first point of interconnection to the New York State electric transmission system when the electricity is not scheduled on a NERC e-Tag, the importer is the facility operator or scheduling coordinator.

(126) 'Electricity Transaction'. The purchase, sale, import, export or exchange of electric power.

(127) 'Electricity wheeled through New York or wheeled electricity'. Electricity that is generated outside New York and delivered into New York with the final point of delivery outside New York. Electricity wheeled through New York is documented on a single NERC e-Tag showing the first point of receipt located outside New York, an intermediate point of delivery located inside New York, and the final point of delivery located outside New

York.

(128) ‘Emission Factor’. A unique value for determining an amount of a GHG emitted for a given quantity of activity (e.g., metric tons of carbon dioxide emitted per barrel of fossil fuel burned.)

(129) ‘Emissions or Greenhouse Gas Emissions’. Gaseous constituents of the atmosphere that absorb and emit radiation at specific wavelengths within the spectrum of terrestrial radiation emitted by the earth’s surface, the atmosphere itself, and by clouds. GHG emissions include carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride, and any other substance emitted into the air that may be reasonably anticipated to cause or contribute to anthropogenic climate change.

(130) ‘Emissions Data Report or Greenhouse Gas Emissions Data Report or Report’. The report prepared by an owner or operator or supplier each year and submitted as prescribed by the department that provides the information required by this Part. The emissions data report is for the submission of required data for the calendar year prior to the year in which the report is due. For example, a 2026 emissions data report would cover emissions and product data for the 2026 calendar year and would be reported in 2027.

(131) ‘Emissions Data Verification Statement’. The final statement rendered by a verification body attesting whether an emission source’s emissions data in its emissions data report is free of material misstatement, and whether the emissions data conforms to the requirements of this Part.

(132) ‘Emission Year’. The calendar year in which emissions occurred, were caused to occur, or an activity that causes or may cause emissions to occur, including the

calendar year in which the final sale or consumption of the fuel or product to an end user occurred in New York.

(133) ‘Emulsion’. Any mixture of crude oil, condensate, or produced water with varying quantities of natural gas entrained in the liquids.

(134) ‘End User’. A final purchaser or consumer of a product, such as fuels, thermal energy, or natural gas not for the purposes of retransmission or resale. In the context of fuels and natural gas consumption, an end user is the point to which natural gas is delivered for consumption. In the context of final sale or consumption of affected liquid fuels, an end user may take possession of the fuel at a filling station.

(135) ‘Energy Services Company or ESCO’. A person eligible to sell energy services to end-use customers using the transmission or distribution system of a utility.

(136) ‘Engineering Estimation’. For the purposes of sections 2.12 of this Part, means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

(137) ‘Enhanced Oil Recovery or EOR’. The use of certain methods such as steam (thermal EOR), water flooding or gas injection into new or existing wells to increase the recovery of crude oil from a reservoir. In the context of this rule, EOR also applies to injection of critical phase CO_2 into a crude oil reservoir to enhance the recovery of oil.

(138) ‘Enterer’. A person who imports into New York affected liquid fuels or petroleum products outside the bulk transfer/terminal system and who is the owner of affected liquid fuels or petroleum product upon import into New York.

(139) ‘Equipment’. Any stationary article, machine, or other contrivance, or combination thereof, which may cause the issuance or control the issuance of air contaminants; equipment shall not mean portable equipment, tactical support equipment, or electricity generators designated as backup generators in a permit issued by the department.

(140) ‘Equipment Leak’. Those emissions from equipment, components, and other point sources that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

(141) ‘Ethane’. A paraffinic hydrocarbon with molecular formula C_2H_6.

(142) ‘Ethanol’. An anhydrous alcohol with molecular formula C_2H

(143) ‘Ethylene’. An olefinic hydrocarbon with molecular formula C_2H_4.

(144) ‘Exchange Agreement’. A commitment between electricity market participants to swap energy for energy. Exchange transactions do not involve transfers of payment or receipts of money for the full market value of the energy being exchanged but may include payment for net differences due to market price differences between the two parts of the transaction or to settle minor imbalances.

(145) ‘Exclusive Marketer’. A marketer that has exclusive rights to market electricity for a generating facility or group of generating facilities.

(146) ‘Exported Electricity’. Electricity generated inside New York and delivered to serve load located outside New York. This includes electricity delivered from a first point of receipt inside New York, to the first point of delivery outside New York, with a final point of delivery outside New York. Exported electricity delivered across balancing authority areas is documented on NERC e-Tags with the first point of receipt located inside New York and the

final point of delivery located outside New York. Exported electricity does not include electricity generated inside New York then transmitted outside of New York, but with a final point of delivery inside New York.

(147) 'External Combustion'. Fired combustion in which the flame and products are separated from contact with the process fluid to which the energy is delivered. Process fluids may be air, hot water, or hydrocarbons. External combustion equipment may include fired heaters, industrial boilers, and commercial and domestic combustion units.

(148) 'Facility'. Unless otherwise specified in relation to natural gas distribution facilities and onshore petroleum and natural gas production facilities as defined pursuant to this Part, means:

(i) Any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right- of-way and under common ownership or common control, that emits, may emit, or may cause to emit any GHG. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

(ii) With respect to natural gas distribution, Facility includes the collection of all distribution pipelines and metering-regulating stations that are operated by a local distribution company within the State of New York.

(149) 'Farm Taps'. Pressure regulation stations that deliver gas directly from transmission pipelines to rural customers. In some cases, a nearby LDC may handle the billing of the gas to the customer(s).

(150) ‘Feedstock’. The raw material supplied to a process.

(151) ‘Field’. In the context of oil and gas systems, means the general area underlaid by one or more pools, or underground reservoirs containing a common accumulation of oil or gas or both.

(152) ‘Field Accuracy Assessment’. A test, check, or engineering analysis intended to confirm that a flow meter or other mass or volume measurement device is operating within an acceptable accuracy range. A field accuracy assessment should be conducted in a manner that does not interrupt operations or require removal of the meter or require primary element inspection. The selected method for field accuracy assessment will vary based on meter type and piping system design, and may be performed by the facility operator, a third-party meter servicing firm, or the original equipment manufacturer.

(153) ‘Filling Station’. Any facility, portion of a facility, or vehicle from which affected liquid fuels are transferred as the final sale or consumption into the fuel tank of a motor vehicle or other portable fuel tank. A filling station includes any temporary storage (at the facility or portion of the facility or in the vehicle) dedicated to holding that liquid fuel or petroleum product before such transfer.

(154) ‘Final Point of Delivery’. The sink specified on the NERC e-Tag, where defined points have been established through the NERC Registry. When NERC e-Tags are not used to document electricity deliveries, as may be the case within a balancing authority, the final point of delivery is the location of the load. Exported electricity is disaggregated by the final point of delivery on the NERC e-Tag.

(155) ‘Final Sale’. The transfer of affected liquid fuels through a filling station to

a vehicle’s tank or other receptacle for temporary storage and later combustion used in the operation of an engine. Or the transfer of liquid fuels or petroleum products to a storage vessel for later utilization in facility processes, products, space heating, equipment, portable equipment, or mechanisms. Includes transfer to storage for later use in non-road engines or equipment or fleet owned vehicles. Includes transfer to storage for later combustion in emergency generators or to create electricity in distributed generation units.

(156) ‘First Deliverer of Electricity or First Deliverer’. The owner or operator of an electricity generating facility in New York or an electricity importer.

(157) ‘First Point of Delivery in New York’. The first defined point on the transmission system located inside New York at which imported electricity and electricity wheeled through New York may be measured, consistent with defined points that have been established through the NERC Registry.

(158) ‘First Point of Receipt’. The generation source specified on the NERC e-Tag, where defined points have been established through the NERC Registry. When NERC e-Tags are not used to document electricity deliveries, as may be the case within a balancing authority, the first point of receipt is the location of the individual generating facility or unit, or group of generating facilities or units. Imported electricity and wheeled electricity are disaggregated by the first point of receipt on the NERC e-Tag.

(159) ‘Fixed Solids’. The solids in waste that are not degradable organic carbon. They are the portion of total solids that are not converted to gases after being brought to 600°C for at least 1 hour plus any petroleum-based plastics that are converted to gases by heating to 600°C for at least 1 hour.

(160) ‘Flare’. A combustion device, whether at ground level or elevated, that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame.

(161) ‘Flare Combustion Efficiency’. The fraction of liquid and gases sent to the flare, on a volume or mole basis, that is combusted at the flare burner tip.

(162) ‘Flare Stack Emissions’. CO_2, N_2O and CH_4 emissions resulting from the incomplete combustion of hydrocarbon gas in the flare.

(163) ‘Flash Analysis’. For purposes of section 2.12 of this Part, means laboratory methodologies for measuring the volume and composition of gases released from liquids, including the molecular weight of the total gaseous sample, the weight percent of individual compounds, and a Gas-Oil Ratio or Gas-Water Ratio required to calculate the specified emission rates as described in section 2.12 of this Part.

(164) ‘Flash Point’. The lowest temperature at which a volatile liquid can vaporize to form an ignitable mixture in air.

(165) ‘Flashing’. A process during which gas dissolved in crude oil, condensate, or produced water under pressure is released when subject to a decrease in pressure, such as when liquids are transferred from an underground reservoir to a tank on the earth’s surface or from a pressure vessel to an atmospheric tank. For purposes of section 2.12 of this Part, means the release of hydrocarbons and carbon dioxide from liquid to surrounding air when the liquid changes temperature and pressure, also known as phase change.

(166) ‘Floating-Piston Cylinder’. A metal cylinder containing an internal pressurized piston for collecting crude oil, condensate or produced water samples. For

purposes of section 2.12 of this Part, means a cylinder used for gathering produced water. The cylinder contains an internal piston controlled by gas pressure. The piston prevents sample liquid from flashing within the sampling cylinder and provides a means of extracting the sample liquid.

(167) ‘Flow Meter’. A measurement device consisting of one or more individual components that is designed to measure the bulk fluid movement of liquid or gas through a piped system at a designated point. Bulk fluid movement can be measured with a variety of devices in units of mass flow or volume.

(168) ‘Flow Monitor’. A component of the continuous emission monitoring system that measures the volumetric flow of exhaust gas.

(169) ‘Fluorinated Greenhouse Gas or Fluorinated GHG’. Greenhouse gases that contain fluorine including sulfur hexafluoride (SF_6), nitrogen trifluoride (NF_3), hydrofluoroolefin, and any fluorocarbon that includes but is not limited to any hydrofluorocarbon, any perfluorocarbon, any fully fluorinated linear, branched or cyclic alkane, ether, tertiary amine or aminoether, any perfluoropolyether, and any hydrofluoropolyether.

(170) ‘Food Waste’. The organic residues generated by the handling, storage, sale, preparation, cooking, and serving of foods.

(171) ‘Fractionates’. The process of separating natural gas liquids into their constituent liquid products.

(172) ‘Fractionator’. Plants that produce fractionated natural gas liquids (NGLs) extracted from produced natural gas and separate the NGLs individual component products:

ethane, propane, butanes and pentane-plus (C5+). Plants that only process natural gas but do not fractionate NGLs further into component products are not considered fractionators. Some fractionators do not process production gas but instead fractionate bulk NGLs received from natural gas processors. Some fractionators both process natural gas and fractionate bulk NGLs received from other plants.

(173) ‘Fuel’. A solid, liquid, or gaseous combustible material.

(174) ‘Fuel Analytical Data’. Data collected about fuel usage (including mass, volume, and flow rate) and fuel characteristics (including heating value, carbon content, and molecular weight) to support emissions calculation.

(175) ‘Fuel Cell’. A device that converts the chemical energy of a fuel and an oxidant directly into electrical energy without using combustion. Fuel cells require a continuous source of fuel and oxidant to operate.

(176) ‘Fuel Characteristic Data’. For the purpose of this Part, properties of a fuel used for calculating GHG emissions including carbon content, high heat value, and molecular weight.

(177) ‘Fuel Ethanol’. Ethanol that meets ASTM D4806-21A “Standard Specification for Denatured Fuel Ethanol for Blending with Gasolines for Use as Automotive Spark-Ignition Engine Fuel” (2021) (see Table 1, section 200.9 of this Title), specifications, for blending with gasolines for use as automotive spark-ignition engine fuel.

(178) ‘Fuel Flowmeter System’. A monitoring system which provides a continuous record of the flow rate of fuel oil or gaseous fuel. A fuel flowmeter system consists of one or more fuel flowmeter components, all necessary auxiliary components (e.g.,

transmitters, transducers, etc.), and a data acquisition and handling system (DAHS).

(179) 'Fuel Production Facility'. A facility, other than a refinery, in which motor vehicle fuel, diesel fuel or biomass-based fuel is produced.

(180) 'Fuel Supplier'. A supplier of natural gas, a supplier of coal, a supplier of affected liquid fuels, and/or a supplier of Liquefied Natural Gas and Compressed Natural Gas.

(181) 'Fuel Transaction'. The record of the exchange of fuel possession, ownership, or title from one person to another.

(182) 'Fugitive Emissions'. Those emissions which are unintentional and could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

(183) 'Full Verification'. All verification services as provided in section 4.2 of this Part.

(184) 'Gas'. The state of matter distinguished from the solid and liquid states by: relatively low density and viscosity; relatively great expansion and contraction with changes in pressure and temperature; the ability to diffuse readily; and the spontaneous tendency to become distributed uniformly throughout any container.

(185) 'Gas Gathering/Booster Stations'. Centralized stations where produced natural gas from individual wells is co-mingled, compressed for transport to processing plants, transmission and distribution systems, and other gathering/booster stations which co-mingle gas from multiple production gathering/booster stations. Such stations may include gas dehydration, gravity separation of liquids (both hydrocarbon and water), pipeline pig launchers and receivers, and gas-powered pneumatic devices.

(186) ‘Gas-to-oil Ratio or GOR’. The ratio of the volume of gas produced in standard cubic feet to each barrel of oil produced concurrently during any stated period.

(187) ‘Gas-to-water Ratio or GWR’. The ratio of gas produced from a barrel of produced water when cooling and depressurizing produced water to standard conditions, expressed in terms of standard cubic feet of gas per barrel of water.

(188) ‘Generated Electricity’. Electricity generated by an electricity generating unit at the emission source. Generated electricity does not include any electricity that is generated outside the facility and delivered into the facility with final destination outside of the facility.

(189) ‘Generated Energy’. Electricity or thermal energy generated by the electricity generating, cogeneration, or bigeneration units included in the emission source.

(190) ‘Generated Thermal Energy’. The thermal energy generated by a cogeneration unit or district heating facility that is sold to particular end-users and reported pursuant to section 2.5(a)(5)(i) of this Part, and the thermal energy used on-site by industrial processes or operations and heating and cooling operations that is not in support of or a part of the electricity generation or cogeneration system and is reported pursuant to section 2.5(a)(5)(iii) of this Part. Generated thermal energy does not include thermal energy that is vented, radiated, wasted, or discharged before it is used at industrial processes or operations, or, for a facility with a cogeneration unit, any thermal energy generated by equipment that is not an integral part of the cogeneration unit.

(191) ‘Generating Unit’. Any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together

to produce electric power.

(192) ‘Generation Providing Entity or GPE’. A facility or generating unit operator, full or partial owner, party to a contract for a fixed percentage of net generation from the facility or generating unit, party to a tolling agreement with the owner, or exclusive marketer recognized by the department that is either the electricity importer or exporter with prevailing rights to claim electricity from the specified source.

(193) ‘Geothermal’. Heat or other associated energy derived from the natural heat of the earth.

(194) ‘Graduated Cylinder’. For purposes of section 2.12 of this Part, means a measuring instrument for measuring fluid volume, such as a glass container (cup or cylinder or flask) which has sides marked with or divided into amounts.

(195) ‘Greenhouse Gas or GHG’. Carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and other fluorinated greenhouse gases.

(196) ‘Greenhouse Gas Emission Reduction or GHG Emission Reduction or Greenhouse Gas Reduction or GHG Reduction’. A calculated decrease in GHG emissions relative to a project baseline or source baseline over a specified period of time.

(197) ‘Greenhouse Gas Emission Source or Emission Source’. Any type of anthropogenic activity that releases, causes the release of, may cause the release of, or contributes to the release of greenhouse gases into the atmosphere.

(198) ‘Grid or Electric Power Grid’. A system of synchronized power providers and consumers connected by transmission and distribution lines and operated by one or

more control centers.

(199) 'Grit'. Any solid material that does not include degradable organic carbon such as sand, most plastics, or metal.

(200) 'Gross Generation or Gross Power Generated'. The total electrical output of the generating facility or unit, expressed in megawatt hours (MWh) per year.

(201) 'GWP20.' An assessment of the Global Warming Potential of greenhouse gases over an integrated 20-year time frame.

(202) 'Gypsum'. A mineral with the chemical formula $CaSO_4 \cdot 2H_2O$.

(203) 'Hazardous Waste'. A material that is defined in Part 371 of this Title to be both a solid waste and a hazardous waste.

(204) 'Heat Input Rate'. The product (expressed in MMBtu/hr) of the gross calorific value of the fuel (expressed in MMBtu/mass of fuel) and the fuel feed rate into the combustion device (expressed in mass of fuel/hr) and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

(205) 'Heavy Crude Oil or Heavy Crude'. A category of crude oil characterized by relatively high viscosity, a higher carbon-to-hydrogen ratio, and a relatively higher density having an API gravity of less than 20.

(206) 'High Bleed Pneumatic Devices'. Automatic, continuous or intermittent bleed flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously or intermittently (bleeds) to the atmosphere at a rate in excess of six standard cubic feet per hour.

(207) ‘High Heat Value or HHV’. The high or gross heat content of the fuel with the heat of vaporization included. The water vapor is assumed to be in a liquid state.

(208) ‘Horsepower Tested’. The total horsepower of all turbine and generator set units tested prior to sale.

(209) ‘Hydraulic Retention Time’. The average time in days that liquid is present in an anaerobic digester or reactor. The hydraulic retention time is equivalent to the average liquid volume held by the equipment divided by the average rate of removal.

(210) ‘Hydrocarbons’. Chemical compounds containing predominantly carbon and hydrogen.

(211) ‘Hydrofluorocarbons or HFCs’. A class of GHGs consisting of hydrogen, fluorine, and carbon.

(212) ‘Hydrogen’. Diatomic molecular hydrogen.

(213) ‘Hydrogen Plant’. A facility that produces hydrogen with steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes.

(214) ‘Imported Electricity’. Electricity generated outside New York and delivered to serve load located inside New York.

(i) Imported electricity includes:

(‘a’) Electricity delivered across balancing authority areas from a first point of receipt located outside New York, to the first point of delivery located inside New York, having a final point of delivery in New York.

(’b’) Electricity imported into New York from a facility or unit physically located outside New York with the first point of interconnection located inside New York State.

('c') Electricity that is a result of cogeneration located outside New York.

(ii) Imported electricity does not include:

('a') Electricity wheeled through New York, defined pursuant to this section.

('b') Electricity imported into New York by an Independent System Operator to obtain or provide emergency assistance under applicable emergency preparedness and operations reliability standards of the North American Electric Reliability Corporation or NPCC.

(215) 'Importer of Fuel'. A person that imports fuel into New York and who is the importer of record under Federal customs law. For imported fuel not subject to Federal customs law, the importer of fuel is the owner of the fuel upon its entering into New York if the eventual transfer of ownership of the product to an end user or marketer located in New York occurs at a location inside New York. However, where the transfer of ownership of the fuel to a New York end user or marketer occurs at a location outside of New York, the "importer of fuel" is the producer, marketer, or distributor that is the seller of the fuel to the end user or marketer located inside New York. Only importers of liquefied petroleum gas, compressed natural gas, and liquefied natural gas are subject to reporting as an importer of fuel.

(216) 'Importer of Record'. The owner or purchaser of the goods that are

imported into New York.

(217) ‘Independently Operated and Sited Cogeneration or Bigeneration Facility’. A cogeneration or bigeneration facility that is not located on the same facility footprint as its thermal host and has different operational control and different ownership than the thermal host.

(218) ‘Independently Operated Cogeneration or Bigeneration Facility Co-Located with the Thermal Host’. A cogeneration or bigeneration facility that is located on the same property footprint as its thermal host but has different operational control and different ownership than the thermal host.

(219) ‘Industrial, Institutional, Commercial Facility with Electricity Generation Capacity’. A facility whose primary business is not electricity generation and includes one or more electricity generating, cogeneration, or bigeneration units.

(220) ‘Industrial Product Data’. All product data or annual production data as required under section 2.22 of this Part.

(221) ‘Industrial Wastewater’. Water containing wastes from an industrial process. Industrial wastewater includes water that comes into direct contact with or results from the storage, production, or use of any raw material, intermediate product, finished product, by-product, or waste product. Examples of industrial wastewater include, but are not limited to, paper mill white water, wastewater from equipment cleaning, wastewater from air pollution control devices, rinse water, contaminated stormwater, and contaminated cooling water.

(222) ‘Intermittent Bleed Pneumatic Devices’. Automated flow control devices

powered by pressurized natural gas and used for automatically maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge all or a portion of the full volume of the actuator intermittently when control action is necessary, but do not bleed continuously. Intermittent bleed devices which bleed at a cumulative rate of six standard cubic feet per hour or greater are considered high bleed devices for the purposes of this regulation.

(223) ‘Internal Combustion’. The combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine, the expansion of the high-temperature and high-pressure gases produced by combustion, applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.

(224) Interstate Pipeline’. A pipeline or that part of a pipeline that is used in the transportation of fuel or carbon dioxide in interstate or foreign commerce.

(225) ‘Intrastate Pipeline’. A gas pipeline facility and transportation of gas within a State not subject to the jurisdiction of the Federal Energy Regulatory Commission under the Natural Gas Act (15 U.S.C. 717 et seq.) (2023) (see Table 1, section 200.9 of this Title). For purposes of this Part, only intrastate pipeline operators that physically deliver gas to end users in New York are subject to reporting under this Part. This definition includes onshore petroleum and natural gas production facilities and natural gas processing facilities, as defined pursuant to this Part, that deliver pipeline and/or non-pipeline quality natural gas to

one or more end users. Facility operators that operate an interconnection pipeline that connects their facility to an interstate pipeline, or that share an interconnection pipeline to an interstate pipeline with other nearby facilities, are not considered intrastate pipeline operators. Facilities that receive gas from an upstream LDC and redeliver a portion of the gas to one or more adjacent facilities are not considered intrastate pipelines.

(226) 'Inventory Position'. A contractual agreement with the terminal operator for the use of the storage facilities and terminaling services for the fuel.

(227) 'ISO'. The International Organization for Standardization.

(228) 'Isobutane'. A paraffinic branch chain hydrocarbon with molecular formula C_4H_{10}.

(229) 'Isobutylene'. An olefinic branch chain hydrocarbon with molecular formula C_4H_8.

(230) 'Isopentane'. The methylbutane or 2-methylbutane, branched chain, isomer of C_5H_{12}.

(231) 'Jurisdiction'. A U.S. state or Canadian province. For purposes of this Part, U.S. state means U.S. State, the District of Columbia, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, and American Samoa and includes the Commonwealth of the Northern Mariana Islands. For purposes of this Part, province means any Canadian province or territory.

(232) 'Kerosene'. A light petroleum distillate with a maximum distillation temperature of 400°F at the 10 percent recovery point, a final maximum boiling point of 572°F, a minimum flash point of 100°F, and a maximum freezing point of -22°F. Includes No.

1-K and No. 2-K, distinguished by maximum sulfur content (0.04 and 0.30 percent of total mass, respectively), as well as all other grades of kerosene called range or stove oil. “Kerosene” does not include kerosene-type jet fuel.

(233) ‘Kerosene-type Jet Fuel’. A kerosene-based product used in commercial and military turbojet and turboprop aircraft. The product has a maximum distillation temperature of 400°F at the 10 percent recovery point and a final maximum boiling point of 572 °F. Includes Jet A, Jet A–1, JP–5, and JP–8.

(234) ‘Kiln’. An oven, furnace, or heated enclosure used for thermally processing a mineral or mineral-based substance.

(235) ‘Landfill’. A facility where waste is intentionally placed and intended to remain and which is designed, constructed, operated and closed to minimize adverse environmental impacts.

(236) ‘Large Emission Sources’. Emission sources meeting the thresholds identified in section 1.2(f) of this Part.

(237) ‘Last Point of Delivery in New York’. The last defined point on the transmission system located inside New York at which exported electricity may be measured, consistent with defined points that have been established through the NERC Registry.

(238) ‘Lead and lead alloys’. Lead or the metal alloy that combines lead and other elements such as antimony, selenium, arsenic, copper, tin, or calcium.

(239) ‘Lead Verifier’. A person that has met all of the requirements in sections 4.3(b) or 4.3(c)(2) of this Part, and who may act as the lead verifier of a verification team providing verification services or as a lead verifier providing an independent review of

verification services rendered.

(240) ‘Lead Verifier Independent Reviewer or Independent Reviewer’. A lead verifier within a verification body who has not participated in conducting verification services for a reporting entity, or authorized project designee for the current reporting year who provides an independent review of verification services rendered to the reporting entity as required in section 4.2 of this Part.

(241) ‘Leak Detection’. The process of identifying equipment leaks or fugitive emissions.

(242) ‘Less Intensive Verification’. The verification services provided in interim years between full verifications; less intensive verification of an emission source’s emissions data report only requires data checks and document reviews of an emission source’s emissions data report based on the analysis and risk assessment in the most current sampling plan developed as part of the most current full verification services. This level of verification may only be used if the verifier can provide findings with a reasonable level of assurance.

(243) ‘Light Crude Oil’. A category of crude oil characterized by relatively low viscosity, a lower carbon-to-hydrogen ratio, and a relatively lower density having an API gravity of greater than or equal to 20.

(244) ‘Limestone’. A sedimentary rock composed largely of the minerals calcite and aragonite, which are different crystal forms of calcium carbonate ($CaCO_3$).

(245) ‘Limited Alternative Emissions’. Those emissions reported for an emission source or sources that are calculated using alternative methods selected by the operator,

subject to the limits specified in section 1.4(e) of this Part.

(246) ‘Liquefied Natural Gas or LNG’ means natural gas (primarily methane) that has been liquefied by reducing its temperature to -260°F at atmospheric pressure.

(247) ‘Liquefied Petroleum Gas or LP-Gas or LPG’. A petroleum hydrocarbon, such as propane, butane or isobutane which is normally a gas but which has been compressed and condensed to a liquid.

(248) 'Liquid Fuel or Petroleum Product’. Fuels or products typically delivered in a liquid form including, but not limited to, Gasoline RBOB; Distillate Fuel Oils; Renewable Diesel; Residual Fuel Oils; Liquified Petroleum Gas, L.P. gas and propane; Kerosene; Jet fuel; Aviation gasoline; Biomass-derived fuels or products; Lubricants; Asphalt and Road Oil; and Petroleum coke.

(249) ‘Liquid Hydrogen’. Hydrogen in a liquid state.

(250) ‘Liquid or Slurry Waste Storage’. A container for waste that is less than or equal to 15 percent solids by mass (kg-dry mass/kg) and is not equipped with surface aerators. The average residence time of waste in a container must be more than two days in order for that container to be considered a storage.

(251) ‘Local Distribution Company or LDC’. For purposes of this Part, means a company that owns or operates distribution pipelines, not interstate pipelines, that physically deliver natural gas to end users and includes public utility gas corporations, publicly owned natural gas utilities and intrastate pipelines that are delivering natural gas to end users.

(252) ‘Lookback Period’. The specified time period of historical data that the operators must use for missing data substitution as required by the regulation.

(253) ‘Low Bleed Pneumatic Devices’. Automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously or intermittently bleeds to the atmosphere at a rate equal to or less than six standard cubic feet per hour.

(254) ‘Marketer’. A purchasing-selling entity that delivers electricity and is not a retail provider.

(255) ‘Material Misstatement’. Any discrepancy, omission, or misreporting, or aggregation of the three, identified in the course of verification services that leads a verification team to believe that the total reported emissions (metric tons of CO_2e) or reported industrial product data contains errors greater than five percent, as applicable, in an emissions data report. Material misstatement is calculated separately for emissions and industrial product data, as specified in section 4.2(b)(11)(i) of this Part.

(256) ‘Maximum Potential Fuel Flow Rate or Maximum Fuel Consumption Rate’. The maximum fuel use rate the source is capable of combusting, measured in physical unit of the fuel (e.g. million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone-dry short tons for biomass-derived solids). When the source consists of multiple units, the maximum potential fuel use rate is the sum of the maximum potential fuel use rates of all the units aggregated as a source.

(257) ‘Megawatt Hour or MWh’. The electrical energy unit of measure equal to one million watts of power supplied to, or taken from, an electric circuit steadily for one hour.

(258) 'Meter/Regulator Run'. A series of components used in regulating pressure or metering natural gas flow or both.

(259) 'Metering/Regulating Station'. A station that meters the flow rate, regulates the pressure, or both, of natural gas. This does not include customer meters, customer regulators, or farm taps.

(260) 'Methane or CH_4'. A GHG consisting of a single carbon atom and four hydrogen atoms.

(261) 'Metric Ton or MT'. A common international measurement for mass, equivalent to 2204.6 pounds.

(262) 'Missing Data Period'. A period of time during which a piece of data is not collected, is invalid, or is collected while the measurement device is not in compliance with the applicable quality-assurance requirements. In the context of periodic fuel sampling, missing data period is the entire sampling period (e.g. week, month, or quarter) for which corresponding fuel characteristic data are not obtained. In the context of periodic fuel consumption monitoring and recording, a missing data period consists of the consecutive time intervals (e.g. hours, days, weeks, or months) for which fuel consumption during the time period is not monitored and recorded.

(263) 'MMBtu'. A million British thermal units.

(264) 'Motor Vehicle Fuel'. Gasoline. It does not include aviation gasoline, jet fuel, diesel fuel, kerosene, liquefied petroleum gas, natural gas in liquid or gaseous form, or racing fuel.

(265) 'Mscf'. One thousand standard cubic feet.

(266) ‘Municipal Solid Waste or MSW’. Municipal solid waste as defined in Part 360 of this Title.

(267) ‘Municipal Wastewater’. Wastewater from domestic, business, and industrial sources that is collected in city sewers and transported to a centralized wastewater treatment system such as a publicly owned treatment works.

(268) ‘Nameplate Generating Capacity’. The maximum electrical output (in MWe) that a generator can sustain over a specified period of time when not restricted by seasonal or other deratings as measured in accordance with the U.S. Department of Energy standards.

(269) ‘Naphthas’. Is a generic term applied to a petroleum fraction with an approximate boiling range between 122°F and 400°F. The naphtha fraction of crude oil is the raw material for gasoline and is composed largely of paraffinic hydrocarbons.

(270) ‘Natural Gas’. A naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases. Its constituents include the greenhouse gases CH_4 and carbon dioxide and may include natural gas liquids.

(271) ‘Natural Gas Distribution Facility’. The collection of all distribution pipelines, metering stations, and regulating stations that are operated by a local distribution company (LDC) that is regulated as a separate operating company by a public service commission or that are operated as an independent municipally owned distribution system.

(272) ‘Natural Gas Driven Pneumatic Pump’. A pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

(273) ‘Natural Gas Liquids or NGLs’. Those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods. Natural gas liquids can be classified according to their vapor pressures as low (condensate), intermediate (natural gasoline), and high (liquefied petroleum gas) vapor pressure. Generally, such liquids consist of ethane, propane, butanes, pentanes, and higher molecular weight hydrocarbons. Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

(274) ‘Natural Gas Liquid Fractionator’. An installation that fractionates natural gas liquids (NGLs) into their constituent liquid products (ethane, propane, normal butane, isobutene or pentanes plus) for supply to downstream facilities.

(275) ‘Natural Gas Supplier or Supplier of Natural Gas’. A person that distributes, supplies, or sells natural gas, renewable natural gas, biogas, biomethane, or blends thereof, to end users in New York, including the following:

(i) a public utility gas corporation operating in New York;

(ii) the owner and operator of an intrastate pipeline that distributes, supplies, or sells natural gas, renewable natural gas, biogas, biomethane, or blends thereof to end users in New York;

(iii) interstate pipeline operator who distributes, supplies, or sells natural gas, renewable natural gas, biogas, biomethane, or blends thereof to end users in New York; and

(iv) an energy services company who distributes, supplies, or sells natural gas, renewable natural gas, biogas, biomethane, or blends thereof to end users in New York.

(276) 'Natural Gasoline'. A mixture of liquid hydrocarbons (mostly pentanes and heavier hydrocarbons) extracted from natural gas. It includes isopentane. Natural gasoline is a natural gas liquid of intermediate vapor pressure.

(277) 'NERC e-Tag'. The North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow between or across balancing authority areas.

(278) 'Net Generation or Net Power Generated'. The gross generation minus station service or unit service power requirements and parasitic load, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.

(279) 'New York'. The State of New York.

(280) 'New York Control Area or NYCA'. The area under the electrical control of the NYISO.

(281) 'New York Independent System Operator or NYISO'. The not-for-profit organization responsible for the efficient and non-discriminatory administration of the wholesale electricity markets in New York State and for the safe and reliable operation of the New York Control Area.

(282) 'Nitric Acid'. HNO_3 of 100 percent purity.

(283) ‘Nitrous Oxide or N_2O’. A GHG consisting at the molecular level of two nitrogen atoms and a single oxygen atom.

(284) ‘Nonconformance’. The failure to use the methods or emission factors specified in this Part to calculate emissions, or the failure to meet any other requirements of the regulation.

(285) ‘Non-Submitted/Non-Verified Emissions Data Report’. An emissions data report that is not submitted to the department by the applicable reporting deadline, or for which a verification statement has not been issued by the applicable verification deadline.

(286) ‘Non-Thermal Enhanced Oil Recovery or Non-Thermal EOR’. The process of using methods other than thermal EOR, which may include water flooding or CO_2 injection, to increase the recovery of crude oil from a reservoir.

(287) ‘North American Industry Classification System (NAICS) code(s)’. The six- digit code(s) that represent the product(s)/activity(s)/service(s) at a facility or supplier as defined in North American Industrial Classification System Manual 2022 (see Table 1, section 200.9 of this Title).

(288) ‘Oil’. Crude petroleum oil and all other hydrocarbons, regardless of API gravity, that are produced at the wellhead in liquid form by ordinary production methods and that are not the result of condensation of gas.

(289) ‘Oil and Gas Systems Specialist’. A verifier accredited to meet the requirements of section 4.2(a)(2) of this Part for providing verification services to operators of petroleum refineries, hydrogen production units or facilities, and petroleum and natural gas systems listed in section 1.2(k) of this Part.

(290) ‘Onshore Petroleum and Natural Gas Production Facility’. All petroleum or natural gas equipment on a well pad, or associated with a well pad or to which emulsion is transferred and EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator that are located in a single basin as defined in 40 CFR § 98.238 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title). When a commonly owned cogeneration plant is within the basin, the cogeneration plant is only considered part of the onshore petroleum and natural gas production facility if the onshore petroleum and natural gas production facility operator or owner has a greater than 50 percent ownership share in the cogeneration plant. Where a person owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person owns or operates in the basin would be considered one facility.

(291) ‘On-site or Onsite’. In the context of GHG reporting means within the facility boundary.

(292) ‘Open-ended Valve or Line’. Any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid and one side open to atmosphere, either directly or through open piping.

(293) ‘Operational Control’. For a facility subject to this Part, means the authority to introduce and implement operating, environmental, health and safety policies. In any circumstance where this authority is shared among multiple persons and one such person holds a permit to operate from the department, that person is considered to have operational control for purposes of this Part.

(294) ‘Operator’. The person, including an owner, having operational control of a facility. Where petroleum and natural gas wells operate without a drilling or operating permit to identify them as an owner or operator, the person that pays the State or Federal business income taxes is considered the owner or operator for the purposes of this Part.

(295) ‘Organics Recycling Facility’. A facility that processes the organic components in waste to produce a mature product for use as a source of nutrients, animal feed, organic matter, liming value, or other essential constituent for a soil to help sustain plant growth. The processes include, but are not limited to, composting, vermiculture, anaerobic digestion, fermentation, and class A processes. An organics waste processing facility also includes processes to convert biodegradable organic components in waste to produce animal feed. The product no longer has the visual appearance of the waste from which it was produced.

(296) ‘Outside of the Facility Boundary’. Not within the physical boundary of the facility (regardless of ownership or operational control), or not in the same operational control of the reporting entity if within the same physical boundary of the facility. For example, a person outside of the facility boundary may include another facility not in the reporting entity’s operational control, another facility under the same operational control but considered a separate facility according to the definition of facility in this section, or an on-site industrial operation (e.g. a cogeneration system) within the facility fence line but that is operated by another operator and for which the on-site industrial operation has not been included in the reporting entity’s GHG report.

(297) ‘Parasitic Load’. The amount of electricity consumed by auxiliary

equipment that supports the electricity generation or cogeneration process. The equipment may include fans, pumps, drive motors, pollution control equipment, lighting, computer, CEMS, and other equipment.

(298) ‘Particular End-User’. A final purchaser of an energy product (e.g., electricity or thermal energy) for whom the energy product is delivered for final consumption and not for the purposes of retransmission or resale.

(299) ‘Pentane’. The n-pentane, straight chain, isomer of C_5H_{12} under the International Union of Pure and Applied Chemistry (IUPAC) nomenclature.

(300) ‘Pentanes Plus or C5+’. A mixture of hydrocarbons that is a liquid at ambient temperature and pressure and consists mostly of pentanes (five carbon chain) and higher carbon number hydrocarbons. Pentanes plus includes normal pentane, isopentane, hexanes-plus (natural gasoline), and plant condensate.

(301) ‘Percent Water Cut’. For purposes of section 2.12 of this Part, means the percentage of water by volume, of the total emulsion throughput as measured using ASTM D4007-22 (2022) (see Table 1, section 200.9 of this Title). The percent water cut is expressed as a percentage.

(302) ‘Perfluorocarbons or PFCs’. A class of greenhouse gases consisting, on the molecular level, of carbon and fluorine.

(303) ‘Performance Review’. An assessment conducted by department of an applicant seeking to become accredited as a verification body, verifier, lead verifier, or sector-specific verifier pursuant to section 4.3 of this Part. Such an assessment may include a review of applicable past sampling plans, verification reports, verification statements, conflict-

of-interest submittals, and additional information or documentation regarding the applicant's fitness for qualification.

(304) 'Person'. Any individual, organization, business entity, limited liability company, company, public or private corporation, political subdivision, government agency, department or bureau of the State, municipality, industry, public district, partnership or co-partnership, association, firm, trust, estate, or any other legal entity.

(305) 'Petroleum'. Oil removed from the earth and the oil derived from tar sands and shale.

(306) 'Petroleum Coke'. A black solid residue, obtained mainly by cracking and carbonizing of petroleum derived feedstocks, vacuum bottoms, tar and pitches in processes such as delayed coking or fluid coking. It consists mainly of carbon (90 to 95 percent), has low ash content, and may be used as a feedstock in coke ovens. This product is also known as marketable coke.

(307) 'Petroleum Refinery or Refinery'. 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. 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.

(308) 'Physical Address'. With respect to a United States parent company as defined in this section, means the street address, city, state, and zip code of that company's physical location.

(309) ‘Pipeline Dig-in’. Unintentional puncture or rupture to a buried natural gas transmission and distribution pipeline during excavation activities.

(310) ‘Pipeline Quality Natural Gas’. For the purpose of calculating emissions under this Part, natural gas having a high heat value greater than 970 Btu/scf and equal to or less than 1,100 Btu/scf, and which is at least 90 percent methane by volume, and which is less than five percent carbon dioxide by volume.

(311) ‘Point of Delivery or POD’. The point on an electricity transmission or distribution system where a deliverer makes electricity available to a receiver, or available to serve load. This point can be an interconnection with another system or a substation where the transmission provider’s transmission and distribution systems are connected to another system.

(312) ‘Point of Receipt or POR’. The point on an electricity transmission or distribution system where an electricity receiver receives electricity from a deliverer. This point can be an interconnection with another system or a substation where the transmission provider’s transmission and distribution systems are connected to another system.

(313) ‘Point Source’. Any separately identifiable stationary point from which greenhouse gases are emitted.

(314) ‘Portable’. Designed and capable of being carried or moved. Indications of portability include, but are not limited to, wheels, skids, carrying handles, dolly, or trailer. Equipment is not portable if any one of the following conditions exists: the equipment is attached to a foundation; the equipment or a replacement resides at the same location or facility for 12 or more consecutive months; the equipment is located at a seasonal facility and

operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year; or the equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.

(315) ‘Portable Pressurized Separator’. A sealed vessel that can be moved from one location to another by attachment to a motor vehicle without having to be dismantled and is used for separating and sampling crude oil, condensate, or produced water at the temperature and pressure of the separator and tank system required for sampling.

(316) ‘Position Holder’. A person that holds an inventory position in motor vehicle fuel, ethanol, distillate fuel, biodiesel, or renewable diesel as reflected in the records of the terminal operator or a terminal operator that owns motor vehicle fuel or diesel fuel in its terminal. Position holder does not include inventory held outside of a terminal, fuel jobbers (unless directly holding inventory at the terminal), retail establishments, or other fuel suppliers not holding inventory at a fuel terminal.

(317) ‘Positive Emissions Data Verification Statement’. A verification statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the emissions data in the submitted emissions data report is free of material misstatement and that the emissions data conforms to the requirements of this Part.

(318) ‘Positive Product Data Verification Statement’. A verification statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the industrial product data in the submitted emissions data report is free of material misstatement and that the industrial product data conforms to the requirements of

this Part.

(319) ‘Positive Verification Statement’. A verification statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement and that the emissions data report conforms to the requirements of this Part. This definition applies to the emissions data verification statement and the product data verification statement.

(320) ‘Power’. Electricity, except where the context makes clear that another meaning is intended.

(321) ‘Power Contract or Written Power Contract’. As used for the purposes of documenting specified versus unspecified sources of imported and exported electricity, means a written document, including associated verbal or electronic records if included as part of the written power contract, arranging for the procurement of electricity. Power contracts may be, but are not limited to, power purchase agreements, enabling agreements, electricity transactions, and tariff provisions, without regard to duration, or written agreements to import or export on behalf of another person, as long as that other person also reports to the department the same imported or exported electricity. A power contract for a specified source is a contract that is contingent upon delivery of power from a particular facility, unit, or asset-controlling supplier’s system that is designated at the time the transaction is executed.

(322) ‘Pressure Relief Valve or Device’. A valve, rupture disk, or similar device used only to release an unplanned, nonroutine discharge of gas from process equipment in order to avoid safety hazards or equipment damage.

(323) ‘Pressure Separator’. A pressure vessel used for the primary purpose of

separating crude oil and produced water or for separating natural gas and produced water.

(324) ‘Pressure Vessel’. Any vessel rated, as indicated by an American Society of Mechanical Engineers (ASME) pressure rating stamp and operated to contain normal working pressures of at least 15 psig without vapor loss to the atmosphere and may be used for the separation of crude oil, condensate, produced water, or natural gas.

(325) ‘Primary Fuel’. The fuel that provides the greatest percentage of the annual heat input to a stationary fuel combustion unit.

(326) ‘Prime Mover’. The type of equipment such as an engine or water wheel that drives an electric generator, including but not limited to reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells.

(327) ‘Process’. The intentional or unintentional reactions between substances or their transformation, including, but not limited to, the chemical or electrolytic reduction of metal ores, the thermal decomposition of substances, and the formation of substances for use as product or feedstock.

(328) ‘Process Emissions’. The emissions from industrial processes involving chemical or physical transformations other than fuel combustion. For example, the calcination of carbonates in a kiln during cement production or the oxidation of methane in an ammonia process results in the release of process CO_2 emissions to the atmosphere. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment.

(329) ‘Process Emissions Specialist’. A verifier accredited to meet the requirements of section 4.2(a)(2) of this Part for providing verification services to operators of

facilities engaged in cement production, glass production, lime manufacturing, pulp and paper manufacturing, iron and steel production, nitric acid production, and lead production.

(330) 'Process Gas'. Any gas generated by an industrial process.

(331) 'Process Heater'. Equipment for the heating of process streams (gases, liquids, or solids) other than water through heat provided by fuel combustion.

(332) 'Process Unit'. The equipment assembled and connected by pipes and ducts to process raw materials and to manufacture either a final or an intermediate product used in the onsite production of other products. The process unit also includes the purification of recovered by products.

(333) 'Process Vent'. An opening where a gas stream is continuously or periodically discharged during normal operation.

(334) 'Produced Water'. The resulting brine that is produced as a byproduct of crude oil or natural gas production.

(335) 'Producer'. A person who owns, leases, operates, controls, or supervises a New York production facility.

(336) 'Product'. An item or category of items manufactured from raw or recycled materials which performs a function or task and is functional upon completion of manufacturing.

(337) 'Product Data'. The sector-specific data specified in Subparts 2 and 5 of this Part, including requirements in 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title).

(338) 'Product Data Verification Statement'. The final statement rendered by a

verification body attesting whether an emission source's industrial product data in its emissions data report is free of material misstatement, and whether the product data conforms to the requirements of this Part.

(339) 'Professional Judgment'. The ability to render sound decisions based on professional qualifications and relevant GHG accounting and auditing experience.

(340) 'Propane'. A paraffinic hydrocarbon with molecular formula C_3H_8.

(341) 'Propylene'. An olefinic hydrocarbon with molecular formula C_3H_6.

(342) 'Public Utility Gas Corporation'. A gas corporation defined in New York Public Service Law section 2 that is also a public utility company or public utility corporation as defined in New York Public Service Law section 2.

(343) 'Publicly Owned Natural Gas Utility'. A municipality or municipal corporation, a municipal utility district, a public utility district, or a joint powers authority that includes one or more of these agencies that furnishes natural gas services to end users.

(344) 'Pump'. A device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

(345) 'Pump Seals'. Any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

(346) 'Purchasing-Selling Entity or PSE'. The person that is identified on a NERC e- Tag for each physical path segment.

(347) 'PURPA Qualifying Facility'. A facility that has acquired a "qualifying facility (QF)" certification pursuant to 18 CFR § 292.207 (April 1, 2024) (see Table 1, section

200.9 of this Title) under the Public Utility Regulatory Policies Act of 1978 (PURPA) (August 9, 2013) (see Table 1, section 200.9 of this Title).

(348) 'QA/QC'. Quality assurance and quality control.

(349) 'Qualified Positive Emissions Data Verification Statement'. A statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the emission source data in the submitted emissions data report is free of material misstatement and is in conformance with section 4.2(b)(8) of this Part, but the emissions data may include one or more other nonconformances with the requirements of this Part that do not result in a material misstatement.

(350) 'Qualified Positive Product Data Verification Statement'. A statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the industrial product data in the submitted emissions data report is free of material misstatement and is in conformance with section 4.2(b)(8) of this Part, but the product data may include one or more other nonconformance(s) with the requirements of this Part that do not result in a material misstatement.

(351) 'Qualified Positive Verification Statement'. A qualified positive emissions data verification statement or qualified positive product data verification statement.

(352) 'Quality-Assured Data or Quality-Assured Value'. The data obtained from a monitoring system that is operating within the performance specifications and the quality assurance/quality control procedures set forth in the applicable rules, for example 40 CFR part 60 (July 1, 2024) or part 75, (July 1, 2023) (see Table 1, section 200.9 of this Title), without unscheduled maintenance, repair, or adjustment.

(353) ‘Rack’ A mechanism for delivering motor vehicle fuel, diesel, or other liquid fuels or products from a refinery or terminal into a truck, trailer, railroad car, or other means of non-bulk transfer.

(354) ‘Reasonable Assurance’. A high degree of confidence that submitted data and statements are valid.

(355) ‘Reciprocating Compressor’. Equipment that increases the pressure of natural gas by positive displacement of a piston in a compression cylinder that is powered by an internal combustion engine or electric motor.

(356) ‘Reciprocating Compressors Rod Packing’. A seal comprised of a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to limit the amount of compressed natural gas that vents into the atmosphere.

(357) ‘Reciprocating Internal Combustion Engine or RICE or Piston Engine’. A reciprocating engine in which power, produced by heat and/or pressure that is developed in the engine combustion chambers by the burning of a mixture of air and fuel, is subsequently converted to mechanical work.

(358) ‘Recyclables Handling and Recovery Facility’. A facility that processes source-separated non-putrescible recyclables.

(359) ‘Recycled’. Refers to a material that is reused or reclaimed.

(360) ‘Refiner’. For purposes of this Part, a person that delivers transportation fuels to end users in New York that were produced by petroleum refineries owned by that person or a subsidiary of that person.

(361) ‘Refinery Fuel Gas or Still Gas’. Gas generated at a petroleum refinery, or

any gas generated by a refinery process unit, and that is combusted separately or in any combination with any type of gas or used as a chemical feedstock.

(362) 'Reformulated Gasoline Blendstock for Oxygenate Blending or RBOB'. The same meaning as defined in 40 CFR § 1090.80 (July 1, 2024) (see Table 1, section 200.9 of this Title).

(363) 'Relative Accuracy Test Audit or RATA'. A method of determining the correlation of continuous emissions monitoring system data to simultaneously collected reference method test data, for example as required in 40 CFR part 60 (July 1, 2024) (see Table 1, section 200.9 of this Title) and 40 CFR part 75 (July 1, 2023) (see Table 1, section 200.9 of this Title).

(364) 'Rendered Animal Fat or Tallow'. Fats extracted from animals which are generally used as a feedstock in making biodiesel.

(365) 'Renewable Diesel'. A motor vehicle fuel or fuel additive that is all of the following:

(i) registered as a motor vehicle fuel or fuel additive under 40 CFR part 79 (July 1, 2024) (see Table 1, section 200.9 of this Title);

(ii) not a mono-alkyl ester;

(iii) intended for use in engines that are designed to run on conventional diesel fuel; and

(iv) derived from nonpetroleum renewable resources.

(366) 'Renewable Energy'. Electrical energy produced by a system that generates electricity or thermal energy through use of the following technologies: solar

thermal, photovoltaics, on land and offshore wind, hydroelectric, geothermal electric, geothermal ground source heat, tidal energy, wave energy, ocean thermal, and fuel cells that do not use a fossil fuel resource in the process of generating electricity.

(367) ‘Renewable Natural Gas’. Biogas that meets pipeline quality natural gas standards.

(368) ‘Reporting Entity’. A facility owner, operator, supplier, or electric power entity subject to the requirements of this Part.

(369) ‘Reporting Period’. The calendar year that coincides with the emission year for the GHG report.

(370) ‘Reporting Year or Report Year’. Emission year.

(371) ‘Reservoir’. Any underground reservoir, natural or artificial cavern or geologic dome, sand or stratigraphic trap whether or not it was previously occupied by or containing oil or gas.

(372) ‘Residue Gas and Residue Gas Compression’. Respectively, production lease natural gas from which gas liquid products and, in some cases, non-hydrocarbon components have been extracted such that it meets the specifications set by a pipeline transmission company, and/or a distribution company; and the compressors operated by the processing facility, whether inside the processing facility boundary fence or outside the fence-line, that deliver the residue gas from the processing facility to a transmission pipeline.

(373) ‘Retail End-Use Customer or Retail End User’. A residential, commercial, agricultural, or industrial electric customer who buys electricity to be consumed as a final product and not for resale.

(374) ‘Retail Outlet or Retail Location’. Any establishment at which liquid fuels are sold or offered for final sale for use in motor vehicles, nonroad engines, nonroad vehicles, or nonroad equipment, including locomotive or marine engines.

(375) ‘Retail Provider’. A person that provides electricity to retail end users in New York and is an EDU, a community choice aggregator, or an ESCO.

(376) ‘Retail Sales’. Means electricity sold to retail end users.

(377) ‘Retailer’. Any person who owns, leases, operates, controls, or supervises a retail outlet.

(378) ‘Sector’. A broad industrial categorization such as specified in section 1.2 of this Part. Sector-specific verifier means a verifier accredited pursuant to section 4.3(c)(5)(i) of this Part, as one or more of the following types of specialists defined pursuant to this section: a transactions specialist, an oil and gas systems specialist, or a process emissions specialist.

(379) ‘Separator’. A sump or vessel used to separate crude oil, condensate, natural gas, produced water, emulsion or solids.

(380) ‘Separator and Tank System’. The first separator in a crude oil or natural gas production system and any tank or sump connected directly to the first separator.

(381) ‘Shale’. A very fine-grained, clastic sedimentary rock that forms when mud, silt, and clay-size mineral particles are consolidated and compacted into relatively impermeable layers. Shale is characterized by a finely laminated or stratified structure and is the most abundant sedimentary rock. Shale can contain varying amounts of organic matter, so it has the potential to become a hydrocarbon source rock. The pore size of shale

reservoirs ranges from nanometers to micrometers. Hydrocarbons in some shale reservoirs can be extracted using hydraulic fracturing.

(382) ‘Shale Gas’. Natural gas produced from wells that are completed in shale formations.

(383) ‘Short Ton’. A common international measurement for mass, equivalent to 2,000 pounds.

(384) ‘Shutdown’. The cessation of operation of an emission source for any purpose.

(385) ‘Simplified Block Diagram’. A diagram consisting of boxes, shapes, lines, arrows, and labels that meets the requirements of section 2.5(a)(6) or section 1.7(c) of this Part. A simplified block diagram is not an architectural drawing or an engineering drawing that shows the likeness of the physical objects being depicted and their actual locations and sizes in scale; it is a simplified graphical representation of the objects being depicted, their relative locations, and how they are connected through flows of energy or energy carrier (e.g. steam, water, electricity, or fuel).

(386) ‘Sink or Sink to Load or Load Sink’. The sink identified on the physical path of NERC e-Tags, where defined points have been established through the NERC Registry. Exported electricity is disaggregated by the sink on the NERC e-Tag, also referred to as the final point of delivery on the NERC e-Tag.

(387) ‘Solid Waste or Waste’. Solid waste or waste as defined in Part 360 of this Title, except as described in section 360.2(a)(3) of this Title.

(388) ‘Solids Retention Time’. The average time in days that solids are held in

an anaerobic digester or reactor. The solids retention time is equivalent to the average mass of solids present in the equipment divided by the average rate at which solids are removed.

(389) ‘Sorbent’. A material used to absorb or adsorb liquids or gases.

(390) ‘Sour Natural Gas’. Natural gas that contains significant concentrations of hydrogen sulfide (H2S) and/or carbon dioxide that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

(391) ‘Source Category’. Categories of emission sources as defined by tables A-3, A-4, and A-5 of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title).

(392) ‘Source of Generation or Generation Source’. The generation source identified on the physical path of NERC e-Tags, where defined points have been established through the NERC Registry. Imported electricity and wheels are disaggregated by the source on the NERC e-Tag, also referred to as the first point of receipt.

(393) ‘Specified Source’. A facility or unit which is permitted to be claimed as the source of electricity delivered. The reporting entity must have either full or partial ownership in the facility/unit or a written power contract to procure electricity generated by that facility/unit. Specified facilities/units include cogeneration systems. Specified source also means electricity procured from an asset-controlling supplier recognized by the department.

(394) ‘Stand-Alone Electricity Generating Facility’. An electricity generating facility whose primary business and sole industrial operation is electricity generation and is not a cogeneration or bigeneration facility.

(395) ‘Standard Conditions or Standard Temperature and Pressure (STP)’.

60°F and 14.7 pounds per square inch absolute.

(396) 'Standard Cubic Foot or SCF'. A measure of quantity of gas, equal to a cubic foot of volume at 60°F and either 14.696 pounds per square inch (1 atm) or 14.73 PSI (30 inches Hg) of pressure.

(397) 'Stationary'. Neither portable nor self-propelled, and operated at a single facility.

(398) 'Station Service'. Electricity that is used to operate an electric generating facility. It includes energy consumed for plant lighting, power, and auxiliary facilities, regardless of whether the electricity is produced at the plant or comes from another source.

(399) 'Steam Generator'. Equipment that produces steam using an external heat source.

(400) 'Storage Tank'. Any tank, other container, or reservoir used for the storage of organic liquids, excluding tanks that are permanently affixed to mobile vehicles such as railroad tank cars, tanker trucks or ocean vessels.

(401) 'Substitute Power or Substitute Electricity'. Electricity that is provided to meet the terms of a power purchase contract with a specified facility or unit when that facility or unit is not generating electricity.

(402) 'Sulfur Hexafluoride or SF_6'. A GHG consisting of a single sulfur atom and six fluorine atoms.

(403) 'Sump'. For purposes of section 2.12 of this Part means a lined surface impoundment or pit in the ground that, during normal operations, is used to temporarily store produced water.

(404) ‘Supplemental Firing’. An energy input to the cogeneration facility used only in the thermal process of a topping cycle plant, or in the electricity generating or manufacturing process of a bottoming cycle cogeneration facility.

(405) ‘Supplier’. A producer, importer, exporter, enterer, position holder, interstate pipeline operator, intrastate pipeline operator, energy service company, or local distribution company of a fossil fuel, fuel, petroleum product, agricultural lime or fertilizer, a fluorinated GHG, or products and systems.

(406) ‘Supplier of Affected Liquid Fuels or Supplier of Liquid Fuels or Petroleum Products’. A person that distributes, sells, transfers, delivers, or supplies affected liquid fuels or blends thereof, including position holders, enterers, and below-the-rack distributors.

(407) ‘Suppliers of Liquefied Natural Gas and Compressed Natural Gas’. A person producing, importing, supplying, distributing, or selling LNG and/or CNG and blends thereof, including:

(i) owners and operators of facilities in New York that make liquefied natural gas products or compressed natural gas products by liquefying or compressing natural gas received from interstate pipelines; and

(ii) importers of liquefied natural gas and compressed natural gas for sale or consumption to end users in New York.

(408) ‘System’. An assemblage of separate components that typically are connected and charged in the field with a fluorinated GHG to perform a function or task.

(409) ‘Tank’. Any container constructed primarily of non-earthen materials used for the purpose of storing, holding, or separating emulsion, crude oil, condensate, or

produced water and that is designed to operate below 15 psig normal operating pressure. For the purposes of section 2.12 of this Part, means a container, constructed primarily of non-earthen materials, used for holding or storing crude oil, condensate, produced water, or emulsion.

(410) ‘Target Temperature’. The temperature at which a pressurized hydrocarbon liquid is flashed and is therefore the temperature of the first atmospheric separator or tank.

(411) ‘Terminal’. A liquid fuel or petroleum product storage and distribution facility that is supplied by pipeline or vessel, and from which liquid fuels and petroleum products may be removed at a rack. Terminal includes a fuel production facility where fuels and products are produced and stored and from which fuel may be removed at a rack. Fuels and products that are not suitable for pipeline transport or supplied in small volumes may be delivered to a terminal by other means.

(412) ‘Terminal Operator’. Any person that owns, operates or otherwise controls a terminal that is supplied by pipeline or vessel and from which accountable fuel products may be removed at a rack.

(413) ‘Thermal Energy’. The thermal output produced by a combustion source used directly as part of a manufacturing process, industrial/commercial process, or heating/cooling application, but not used to produce electricity.

(414) ‘Thermal Enhanced Oil Recovery or Thermal EOR’. The process of using injected steam to increase the recovery of crude oil from a reservoir.

(415) ‘Thermal Host’. The user of the steam or heat output of a cogeneration or

bigeneration facility.

(416) ‘Throughput’. For natural gas, the average volume of gas such as mcf/day or mcf/year. For crude oil, the average volume of liquid processed by a vessel over a period of time, such as barrels per day. The throughput of crude oil or condensate may need to be calculated using the Percent Water Cut. The throughput of crude oil or condensate is calculated as the difference in volume between these liquids and the produced water. For cement, the maximum short tons of raw material put through the kiln. For iron/steel, the maximum capacity of carbon containing inputs and outputs put through the system.

(417) ‘Tier’. The level of calculation method from 40 CFR § 98.33 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) that is required for a stationary combustion source in section 2.7 of this Part.

(418) ‘Tier 1’. A stationary combustion calculation method that applies default values for emission factors and high heat value to generate an emissions estimate, as specified in 40 CFR § 98.33 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title).

(419) ‘Tier 2’. A stationary combustion calculation method that applies a default value for an emission factor and a fuel’s measured high heat value (or a boiler efficiency for steam-generating solid fuels) to generate an emissions estimate, as specified in 40 CFR § 98.33 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title).

(420) ‘Tier 3’. A stationary combustion calculation method that uses a fuel’s measured carbon content to generate an emissions estimate, as specified in 40 CFR § 98.33 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title).

(421) 'Tier 4'. A stationary combustion calculation method that uses quality assured data from a continuous emission monitoring system to generate an emissions estimate, as specified in 40 CFR § 98.33 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title). This method may also capture process emissions from a common stack.

(422) 'Tight Gas'. Natural gas produced from low-permeability sandstone and carbonate reservoirs.

(423) 'Tolling Agreement'. An agreement whereby a person rents a power plant from the owner. The rent is generally in the form of a fixed monthly payment plus a charge for every MW generated, generally referred to as a variable payment.

(424) 'Topping Cycle'. A type of cogeneration system in which the energy input to the plant is first used to produce electricity, and at least some of the reject heat from the electricity production process is then used to provide useful thermal output.

(425) 'Total Solids'. The mass of the material that remains after water is removed from waste by drying at 105°C until a constant mass is reached. Total solids in a sample equal the sum of volatile and fixed solids.

(426) 'Total Thermal Output'. The total amount of usable thermal energy generated by a cogeneration or bigeneration unit that can potentially be made available for use in any industrial or commercial processes, heating, or cooling applications, or delivered to other end users. This quantity excludes the heat content of returned condensate and makeup water, but includes the thermal energy used for supporting (but not directly used for) power generation, thermal energy used in other on-site processes or applications that are not in support of or a part of the electricity generation system, thermal energy provided or sold to

a particular end-user, and thermal energy that is otherwise not used. Thermal energy directly used for power generation (e.g., steam used to drive a steam turbine generator for electricity generation) is not included in total thermal output.

(427) 'Traceable'. That a standard used to calibrate a device has an unbroken chain of comparisons to a stated reference (such as a standard set by the National Institute of Standards and Technology), with each comparison having a stated uncertainty.

(428) 'Transactions Specialist'. A verifier accredited to meet the requirements of section 4.2(a)(2) of this Part for providing verification services to electric power entities; suppliers of petroleum products and biofuels; suppliers of natural gas, natural gas liquids, and liquefied petroleum gas; and suppliers of CO_2.

(429) 'Transmission-Distribution (T-D) Transfer Station'. A metering-regulating station where a local distribution company takes part or all of the natural gas from a transmission pipeline and puts it into a distribution pipeline.

(430) 'Transmission Pipeline'. A high-pressure cross-country pipeline transporting saleable quality natural gas from production or natural gas from processing to natural gas distribution pressure let-down, metering, regulating stations, where the natural gas is typically odorized before delivery to customers.

(431) 'Transporter or Solid Waste Transporter'. A person engaged in the off-site transportation of waste by means of air, rail, highway, or water conveyance.

(432) 'Turbine'. Any of various types of machines in which the kinetic energy of a moving fluid is converted into mechanical energy by causing a bladed rotor to rotate.

(433) 'Turbine Meter'. A flow meter in which a gas or liquid flow rate through the

calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

(434) ‘Type of Thermal Energy Product’. The form in which energy is transferred from a facility producing thermal energy to another facility, or if not transferred, the form in which the energy is used. Types of thermal energy products include steam, hot water, chilled water, and distilled water.

(435) ‘Uncertainty’. The degree to which data or a data system is deemed to be indefinite or unreliable.

(436) ‘United States Parent Company(s)’. The highest-level United States company(s) with an ownership interest in the reporting entity as of December 31 of the reporting year.

(437) ‘Unspecified Source of Electricity or Unspecified Source’. A source of electricity that is not a specified source at the time of entry into the transaction to procure the electricity.

(438) ‘Unspecified Waste’. Solid waste transported outside of New York for which the ultimate destination or location is unknown or is not a hazardous waste, combustion, composting, organics processing, organics recycling, or recyclables handling and recovery facility.

(439) ‘Upstream Entity’. The last person in the chain of title prior to the fuel being received by the reporting entity.

(440) ‘Upstream Out of State Emissions'. Greenhouse gases produced outside of the state that are associated with the generation of electricity imported into the state and

the extraction and transmission of fossil fuels imported into the state.

(441) ‘U.S. EPA or EPA’. The U.S. Environmental Protection Agency.

(442) ‘Vapor Recovery System’. Any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel.

(443) ‘Vegetable Oil’. Oils extracted from vegetation that are generally used as a feedstock in making biodiesel.

(444) ‘Vented Emissions’. CH_4, CO_2, or other greenhouse gases released to the atmosphere through seals or vent pipes, components, equipment, equipment blowdown, or direct venting of gas used to power equipment (such as pneumatic devices). Such emissions are typically associated with natural gas or hydrocarbon gas, not including stationary combustion flue gas.

(445) ‘Verification’. A systematic, independent and documented process for evaluation of a reporting entity’s emissions data report against the department’s reporting procedures and methods for calculation and reporting GHG emissions and product data as contained in this Part.

(446) ‘Verification Body’. A firm with accreditation from or accepted by the department that is able to render a verification statement and provide verification services for Reporting Entities subject to reporting under this Part.

(447) ‘Verification Services’. Services provided during verification as specified in section 4.2 of this Part.

(448) 'Verification Statement'. The final statement rendered by a verification body attesting whether a reporting entity's emissions data report is free of material misstatement, and whether it conforms to the requirements of this Part.

(449) 'Verification Team'. All of those working for a verification body, including all subcontractors, to provide verification services for a reporting entity.

(450) 'Verified Emissions Data Report'. An emissions data report that has been reviewed by a third-party verifier and has a verification statement, or statements, if applicable, submitted to the department.

(451) 'Verifier'. A natural person accredited by the department to carry out verification services as specified in section 4.2 of this Part.

(452) 'Verifier Review'. A verifier conducts all reviews and services in section 4.2 of this Part, except the material misstatement assessment pursuant to section 4.2(b)(11) of this Part.

(453) 'Vessel'. For the purposes of section 2.12 of this Part, means any container constructed primarily of non-earthen materials used for the purpose of storing, holding, or separating emulsion, crude oil, condensate, or produced water and that is designed to operate below a normal operating pressure of 15 psig.

(454) 'Volatile Solids or VS'. The portion of total solids in waste that can be converted to gases when brought to 600°C for at least 1 hour exclusive of any petroleum-based plastics.

(455) 'Well'. A boring in the earth for the purpose of the following:

(i) Exploring for or producing oil or gas.

(ii) Injecting fluids or gas for stimulating oil or gas recovery.

(iii) Re-pressuring or pressure maintenance of oil or gas reservoirs.

(iv) Disposing of oil field waste gas or liquids.

(v) Injection or withdrawal of gas from an underground storage facility.

(456) ‘Waste Gas’. A natural gas that contains a greater percentage of gaseous chemical impurities than the percentage of methane. For purposes of this definition, gaseous chemical impurities may include carbon dioxide, nitrogen, helium, or hydrogen sulfide.

(457) ‘Well Completions’. The process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment, steps that do not significantly vent natural gas to the atmosphere. This process may also include high rate flowback of injected gas, water, oil, and proppant used to fracture or re-fracture and prop open new fractures in existing lower permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

(458) ‘Well Testing Venting and Flaring’. Venting and/or flaring of natural gas at the time the production rate of a well is determined for regulatory, commercial, or technical purposes. If well testing is conducted immediately after a well completion or workover, then it is considered part of well completion or workover.

(459) ‘Well Workover’. The process(es) of performing one or more of a variety of maintenance or remedial operations on existing petroleum and natural gas wells to

increase or restore production. This process also includes high-rate flowback of injected gas, water, oil, and proppant used to re-fracture and prop-open new fractures in existing low permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

(460) ‘Wellhead’. The piping, casing, tubing and connected valves protruding above the earth’s surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. Wellhead equipment includes all equipment, permanent and portable, located on the improved land area (i.e. well pad) surrounding one or multiple wellheads.

(461) ‘Wet Natural Gas’. Natural gas in which water vapor exceeds the concentration specified for commercially saleable natural gas delivered from transmission and distribution pipelines. This input stream to a natural gas dehydrator is referred to as “wet gas”.

(462) ‘Wood Residuals’. Materials recovered from three principal sources: Municipal solid waste (MSW); construction and demolition debris; and primary timber processing. Wood residuals recovered from MSW include wooden furniture, cabinets, pallets and containers, scrap lumber (from sources other than construction and demolition activities), and urban tree and landscape residues. Wood residuals from construction and demolition debris originate from the construction, repair, remodeling and demolition of houses and non-residential structures. Wood residuals from primary timber processing include bark, sawmill slabs and edgings, sawdust, and peeler log cores. Other sources of wood residuals include, but are not limited to, railroad ties, telephone and utility poles, pier and dock timbers,

wastewater process sludge from paper mills, trim, sander dust, and sawdust from wood products manufacturing (including resinated wood product residuals), and logging residues.

253-1.4 Greenhouse Gas Reporting Requirements

(a) Emissions Monitoring and Reporting. Owners or operators of emission sources specified in section 1.2 of this Part must monitor emissions and submit emissions data reports to the department, except as otherwise provided in this Part, following the requirements specified in 40 CFR § 98.3 through .4 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) and, as applicable, section 2.21(b) of this Part.

(b) Reporting Deadlines. Each reporting entity must submit an emissions data report no later than June 1 of each emission year.

(c) Verification Requirement and Deadlines. The requirements of this subdivision apply to each reporting entity that has met any of the applicability requirements pursuant to section 1.2(f) of this Part in any year. These requirements also apply to each reporting entity that has not met the requirements for cessation of verification in section 1.2(n) or section 1.2(o) of this Part. Each reporting entity subject to verification must obtain third-party verification services for that report from a verification body that meets the requirements specified in Subpart 4 of this Part. Such services must be completed, and separate verification statements for emissions data and for product data, as applicable, must be submitted by the verification body to the department, by August 10 each year. Each reporting entity must ensure that these verification statements are submitted by this deadline. Contracting with a verification body without providing sufficient time to complete the verification statements by the applicable deadline will not excuse the reporting entity from this responsibility. These requirements are additional to the requirements in 40 CFR § 98.3(f) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title).

(d) Non-submitted/Non-verified Emissions Data Reports. The department may develop and assign an emissions level for an emission source that fails to submit an emissions data report or fails to obtain a positive emissions data verification statement or qualified positive emissions data verification statement by the applicable deadline. The department shall develop an assigned emissions level for the emission source as set forth in section 4.2(c)(5)(i) through (iii) of this Part.

(e) Calculation and Reporting of Limited Alternative Emissions. A facility operator may represent no more than three percent of a facility's total CO_2 equivalent emissions (including emissions from biomass-derived fuels and feedstocks), not to exceed 20,000 metric tons of CO_2e as limited alternative emissions. The reporting entity may estimate limited alternative emissions using methods of the operator's choosing, subject to the concurrence of the verification body that the methods used are reasonable, not biased toward significant under estimation or over estimation of emissions, and unlikely to exceed three percent of the reported emissions or 20,000 metric tons CO_2e. The reporting entity must separately identify and include in the emissions data report the emissions designated as limited alternative emissions. The reporting entity must determine CO_2 equivalence according to the CO_2 equivalence definition of this Part.

(f) Calculating, Reporting, and Verifying Emissions from Biomass-Derived Fuels. The reporting entity must separately identify and report all biomass-derived fuels. Except for a reporting entity that uses the methods of 40 CFR § 98.33(a)(2)(iii) or § 98.33(a)(4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), the reporting entity must separately identify, calculate, and report all direct emissions of CO_2 resulting from the combustion of biomass-derived fuels as specified in sections 2.5 and 2.7 of this Part for facilities, and sections 2.16 and 2.17 of this Part for suppliers. The reporting entity must meet the verification requirements in section 4.2(i) of this Part for biomass-derived fuels. Carbon dioxide combustion emissions from biomass-derived fuel will be identified as biomass-derived CO_2.

(1) When reporting solid waste, the reporting entity must separately report the mass, in short tons, of wood residuals recovered from construction and demolition (C&D) debris, agricultural waste, and municipal solid waste (MSW).

(2) When reporting the use of wood residuals from primary timber processing as a fuel, the reporting entity must report: the bone-dry mass received; information about the supplier, including the name, physical address, mailing address, contact person with phone number and e-mail address; and the corresponding identification number under which the wood was removed.

(3) When reporting biomethane, the reporting entity that is reporting biomass emissions from biomethane fuel must also report the following information for each contracted delivery:

(i) name and address of the biomethane vendor from which biomethane is purchased;

(ii) annual MMBtu delivered by each biomethane vendor.

(4) The reporting entity must also report the name, address, and facility type of the facility from which the biomethane is produced. In addition, relevant documentation including invoices, shipping reports, allocation and balancing reports, storage reports, in-kind nomination reports, and contracts must be made available for verifier or departmental review to demonstrate the receipt of eligible biomethane.

(5) Reporting of fuel consumption from biomass-derived fuel is subject to the requirements of subdivision (g) of this section and reporting of emissions from biomass-derived fuels is subject to the requirements of this Part.

(g) Measurement Accuracy Requirement. A reporting entity that does not meet the thresholds specified in section 1.2(f) of this Part, that is subject to the requirements of 40 CFR § 98.3(i) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) must meet those requirements for data used for calculating emissions or product data, except as otherwise specified in this subdivision. In addition, the following accuracy requirements apply to data used for calculating emissions and industrial product data for emission sources as specified in section 1.2(f) of this Part. A reporting entity that meets the requirements of section 1.2(f) in any reporting year must meet the requirements of paragraphs (1) through (10) of this subdivision for calibration and measurement device accuracy. Inventory measurement, stock measurement, or tank drop measurement methods are subject to paragraph (11) of this subdivision. The requirements of paragraphs (1) through (11) of this subdivision apply to fuel consumption monitoring devices, feedstock consumption monitoring devices, process stream flow monitoring devices, steam flow devices, product data measuring devices, mass and fluid flow meters, weigh scales, conveyer scales, gas chromatographs, mass spectrometers, calorimeters, and devices for determining density, specific gravity, and molecular weight. The provisions of paragraphs (1) through (11) of this subdivision do not apply to: stationary fuel combustion units that use the methods in 40 CFR § 98.33(a)(4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) to calculate CO_2 mass emissions; emissions reported as limited alternative emissions under subdivision (e) of this section; and devices that are solely used to measure parameters used to calculate emissions or product data from Reporting Entities that do not meet the thresholds specified in section 1.2(f) of this Part. Provisions of paragraphs (1) through (9) and (11) of this subdivision do not apply to stationary fuel combustion units that use the methods in 40 CFR part 75 appendix G § 2.3 (July 1, 2023) (see Table 1, section 200.9 of this Title) to calculate CO_2 mass emissions, but the provisions in paragraph (10) of this subdivision are applicable to such units.

(1) Except as otherwise provided in paragraphs (7) through (9) of this subdivision, all flow meter and other measurement devices used to provide data for the GHG emissions calculations or industrial product data must be calibrated prior to the year data collection is required to begin using the procedures specified in this section, and subsequently recalibrated according to the frequency specified in paragraph (4) of this subdivision. Each meter or measurement device must meet the applicable accuracy specification in paragraph (6) of this subdivision; however, each individual component of a flow meter device is not required to meet the accuracy specifications. The procedures and methods used to quality assure the data from each measurement device must be documented in the written monitoring plan required by section 1.7(e) of this Part.

(2) All flow meters and other measurement devices that provide data used to calculate GHG emissions or product data must be calibrated according to either the manufacturer's recommended procedures or a method specified in an applicable subpart of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title). The calibration method(s) used must be documented in the monitoring plan required under section 1.7(e) of this Part and are subject to verification under this Part and review by the department to ensure that measurements used to calculate GHG emissions or product data have met the accuracy requirements of this section.

(3) For facilities and suppliers that become subject to this Part after January 1, 2025, all flow meters and other measurement devices that provide data used to calculate GHG emissions or product data must be installed and calibrated no later than the date on which data collection is required to begin under this Part.

(4) Except as otherwise provided in paragraphs (7) through (9) of this subdivision, subsequent recalibrations of the flow meter and other measurement devices subject to the requirements of this section must be performed no less frequently than at one of the following time intervals, whichever is shortest:

(i) the frequency specified in a subpart of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) that is applicable under this Part;

(ii) the frequency recommended by the manufacturer;

(iii) once every 36 months;

(iv) immediately upon replacement of a previously calibrated meter.

(v) immediately upon replacement or repair of a device that is deemed out of calibration as determined in paragraph (6) of this subdivision; or

(vi) if the device manufacturer explicitly states in the product documentation that calibration is required at a period exceeding three years, the operator may follow the procedures in paragraph (9) of this subdivision to obtain department approval to relieve the operator from having to comply with subparagraphs (i) and (iii) of this paragraph.

(5) All standards used for calibration must be traceable to the National Institute of Standards and Technology or other similar national government body responsible for measurement standards.

(6) In addition to the specific calibration requirements specified in subparagraph (i) of this paragraph, and, if applicable, the field accuracy assessment requirements specified in subparagraph (ii) of this paragraph, all flow meter and other measurement devices covered by this section, regardless of type, must be selected, installed, operated, and maintained in a manner to ensure accuracy within ±5 percent.

(i) Perform all mass and volume measurement device calibration as specified in the original equipment manufacturers (OEM) documentation. If OEM documentation is unavailable, calibrate as specified in 40 CFR § 98.3(i)(2) through (3) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), except that a minimum of three calibration points must be used spanning the normal operating conditions. When using the three calibration points, one point must be at or near the zero-point, one point must be at or near the upscale point, and one point at or near the mid- point of the device’s operating range. If OEM documentation does not specify a method or is unavailable, and calibration methods specified in 40 CFR §98.3(i)(2) through (3) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) are not possible for a particular device, the procedures in section 1.11(b) of this Part must be followed to obtain approval for an alternative calibration procedure. Additionally:

(‘a’) Pressure differential devices must be inspected at a frequency specified in paragraph (4) of this subdivision unless the device is located at a refinery or hydrogen plant that operates continuously with infrequent outages. In such cases, the owner or operator of the refinery or hydrogen plant must inspect each device at a frequency of at least once every six years. The inspection must be conducted as described in the appropriate part of ISO 5167-2: 2022 Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full Part 2: Orifice plates (see Table 1, section 200.9 of this Title), or American Gas Association Report No. 3 Part 2 (2003) (see Table 1, section 200.9 of this Title), or a method published by an organization listed in 40 CFR § 98.7 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) applicable to the analysis being conducted. If the device fails any one of the tests, then the meter shall be deemed out of calibration. If OEM guidance for a particular pressure differential device recommends against disassembly and inspection of the device, disassembly and inspection requirements in this paragraph do not apply. Documentation of OEM guidance must be made available to verifiers and the department upon request.

(‘1’) Records of all tests, including an as-found condition, must be preserved pursuant to section 1.7 of this Part and made available to verifiers and the department upon request.

('2') Where inspection requirements apply, the primary element must also be photographed on both sides prior to any treatment or cleanup of the element to clearly show the condition of the element as it existed in the pipe.

('b') Devices used to measure total pressure and temperature must be calibrated using methods specified in paragraph (2) of this subdivision and at a frequency specified in paragraph (4) of this subdivision.

('c') If temperature and/or total pressure measurements are not available or are taken at a remote location, the uncertainty caused by this must be factored into the evaluation of the overall measurement accuracy required under paragraph (6) of this subdivision.

(ii) Operators and suppliers may conduct an annual field accuracy assessment of mass and volume measurement devices to test for field accuracy in years between successive calibrations to ensure the device is maintaining measurement accuracy within ±five percent. When performing a field accuracy assessment, the as-found condition must be recorded to ensure the device is measuring with accuracy within ±five percent. Should a device be found to be operating outside the ±five percent accuracy bounds, the device shall be deemed out of calibration. Records of all field accuracy assessments must clearly indicate the assessment procedure and the as-found condition, be preserved pursuant to section 1.7 of this Part, and be made available to verifiers and the department upon request. Device accuracy may be assessed using one of the following options:

('a') engineering analysis;

('b') OEM calibration guidance or other OEM recommended methods;

('c') standard industry practices; or

('d') portable instruments.

(iii) Pursuant to paragraph (10) of this subdivision, in the event of a failed calibration or recalibration, operators or suppliers who choose not to perform the annual field accuracy assessment specified in subparagraph (ii) of this paragraph for one or more mass or volume measurement devices must demonstrate data accuracy going back multiple years to the most recent successful calibration. Multiple years of data may be deemed invalid if accuracy cannot be demonstrated by other means, including strap-on meters or engineering methods. For operators and suppliers who conduct the annual field accuracy assessment, and a device is found to be out of calibration, accuracy must be demonstrated back to the most recent successful calibration or the most recent successful field accuracy assessment, whichever is most recent.

(7) The requirements of this subdivision do not apply under the following circumstances:

(i) Financial transaction meters are exempted from the calibration requirements of this subdivision if the supplier and purchaser do not have any common owners and are not owned by subsidiaries or affiliates of the same company. Financial transaction meters where the supplier and the purchaser do have common owners or are owned by subsidiaries or affiliates of the same company are exempt from the calibration requirements of this subdivision if one of the following is true:

(‘a’) the financial transaction meter is also used by other companies that do not share common ownership with the fuel supplier; or

(‘b’) the financial transaction meter is sealed with a valid seal from the county sealer of weights and measures or from a county certified designee; or

(‘c’) the financial transaction meter is operated by a third-party.

(ii) Upstream ethanol and additive meters used to ensure proper blendstock percentage for finished gasoline are exempted from the calibration requirements of this subdivision.

(iii) Non-financial transaction meters used by Public Utility Gas Corporations for purposes of reporting natural gas supplier emissions are exempt from the calibration requirements in paragraphs (1) through (6) of this subdivision if the supplier can demonstrate that the meters are operated and maintained in conformance with a standard that meets the measurement accuracy requirements of Chapter III of Title 16.

(8) For units and processes that operate continuously with infrequent outages, it may not be possible to meet deadlines for the initial or subsequent calibrations of a flow meter or other fuel measurement or sampling device, or inspection of orifice plates without disrupting normal process operation. In such cases, the owner or operator may submit a written request to the department to postpone calibration or inspection until the next scheduled maintenance outage. Such postponements are subject to the procedures of paragraph (9) of this subdivision and must be documented in the monitoring plan that is required under section 1.7(e) of this Part.

(9) In cases of continuously operating units and processes where calibration or

inspection is not possible without operational disruption, the operator must demonstrate by other means to the satisfaction of the department that measurements used to calculate GHG emissions and product data still meet the accuracy requirements of paragraph (6) of this subdivision. The department must approve any postponement of calibration or required recalibration beyond January 1, 2026.

(i) A written request for postponement must be submitted to the department not less than 30 days before the required calibration, recalibration, or inspection date. The department may request additional documentation to validate the operator's claim that the device meets the accuracy requirements of this section. The operator shall provide any additional documentation to the department within 10 working days of a request by the department.

(ii) The request must include:

('a') the date of the required calibration, recalibration, or inspection;

('b') the date of the last calibration or inspection;

('c') the date of the most recent field accuracy assessment, if applicable;

('d') the results of the most recent field accuracy assessment, if applicable, clearly indicating a pass/fail status;

('e') the proposed date for the next field accuracy assessment, if applicable;

('f') the proposed date for calibration, recalibration, or inspection which must be during the time period of the next scheduled shutdown. If the next shutdown will not occur within three years, this must be noted and a new request must be received every three years until the shutdown occurs and the calibration, recalibration or inspection is completed.

('g') a description of the meter or other device, including at a minimum:

('1') make;

('2') model;

('3') install date;

('4') location;

('5') annual emissions calculated or annual product data reported using data from the device;

('6') sources for which the device is used to calculate emissions or product data;

('7') calibration or inspection procedure;

('8') reason for delaying calibration or inspection;

('9') proposed method to assure the accuracy requirements of paragraph (6) of this subdivision are met; and

('10') name, title, phone number and e-mail of contact person capable of responding to questions regarding the device.

(10) If the results of an initial calibration, recalibration, or field accuracy assessment fail to meet the required accuracy specification, and the emissions or product

data estimated using the data provided by the device represent more than five percent of total facility emissions or product data on an annual basis, the operator must demonstrate by other means to the satisfaction of the verifier or the department that measurements used to calculate GHG emissions and product data still meet the ±five percent accuracy requirements going back to the last instance of successful field accuracy assessment or calibration of the device. Where the results of an initial calibration, recalibration, or field accuracy assessment fail to meet the accuracy specifications, the verifier shall note at a minimum a nonconformance as part of the emissions data verification statement.

(11) When using an inventory measurement, stock measurement, or tank drop measurement method to calculate volumes and masses, the method must be accurate to ±five percent for the time periods required by this Part, including annually for industrial product data. Techniques used to quantify amounts stored at the beginning and end of these time periods are not subject to the calibration requirements of this section. Uncertainties in beginning and end amounts are subject to verifier review for material misstatement under section 4.2(b)(11) of this Part. If any devices used to measure inputs and outputs do not meet the requirements of paragraphs (1) through (10) of this subdivision, the verifier must account for this uncertainty when evaluating material misstatements. Reported values must be calculated using Equations 1.4-1 and 1.4-2 as provided in this paragraph:

Equation 1.4-1: Fuel consumed (volume or mass) = (inputs during time period – outputs during time period) + (amount stored at beginning of time period) – (amount stored at end of time period)

Equation 1.4-2: Product produced (volume or mass) = (outputs during time period - inputs during time period) + (amount stored at end of time period - amount stored at beginning of time period)

(h) Reporting and Verifying Product Data. The reporting entity must separately identify, quantify, and report all product data as specified in sections 2.3, 2.11, and 2.12 of this Part. It is the responsibility of the reporting entity to obtain verification services for the product data. Product data will be evaluated for conformance and material misstatement independent of GHG emissions data. Industrial product data is evaluated for material misstatement and conformance, while the remaining reported product data is evaluated for conformance only. Emission sources must exclude inaccurate industrial product data and may elect to exclude accurate industrial product data. Reporting Entities that exclude industrial product data must report a description of the excluded data and an estimated magnitude using best available methods. The excluded industrial product data will not be used for the material misstatement assessment or for the total industrial product data variable described in section 4.2(b)(11)(i) of this Part. Operators of cement plants may not exclude industrial product data.

(i) Changes in Methodology. Except as specified below, where this Part permits a choice between different methods for the monitoring and calculation of GHGs and product data, the reporting entity must use the method chosen for all future emissions data reports, except as provided pursuant to paragraphs (1) and (2) of this subdivision.

(1) Changes in Prescribed Methods.

(i) Permanent Improvement in Monitoring or Calculation Methodology for Emissions Data. The reporting entity is permitted to permanently improve the emissions or product data monitoring or calculation method to a higher-tier monitoring or calculation method specified in this Part, such as the addition of a continuous emissions monitoring system. Permanent improvements to emissions monitoring or calculation methods do not require approval in advance by the department; however, the reporting entity must notify the department by the reporting deadline for the applicable reporting year.

(ii) Permanent Change to a Lower-Tier Methodology for Emissions Data. The reporting entity is permitted to submit a request for approval of a permanent change to a lower tier monitoring or calculation method specified in this Part for emissions data. The request must be provided to the department prior to January 1 of the year for which the data will be reported and must be approved by the department and implemented pursuant to the timing requirements in paragraphs (2) through (3) of this subdivision. The request must include a description of why the change in method is being proposed, a detailed description of the data that are affected by the method change, and a demonstration of differences in estimated data under the current and proposed methods.

(iii) Permanent changes to all industrial product data monitoring or calculation methods must be submitted to the department pursuant to paragraph (2) of this subdivision, except in the circumstances described in paragraph (4) of this subdivision.

(2) Alternative Methods. If a reporting entity identifies a situation where conventional metering or methods are not feasible, the reporting entity may submit a request to the department for approval of an alternative measurement/monitoring method that

achieves accuracy at an equivalent level to the ±five percent required by paragraph (g)(6) of this section. The alternative method request must be provided to the department prior to January 1 of the year for which the new method would be implemented for data collection. The request must include a description of why the change in method is being proposed, include a detailed description of the data that are affected by the alternative measurement/monitoring method, and include a demonstration of differences in estimated data under the current and proposed methods. The department may also approve the use of the alternative method in the current reporting year provided the reporting entity makes that request and shows that it has collected the necessary data to apply the alternative method to the entire current year.

(3) When permitted under paragraphs (1) and (2) of this subdivision, a change in the calculation or monitoring method must be made for an entire emission year and apply to the start of an emission year, except in the circumstances described in paragraph (4) of this subdivision.

(4) Use of a Temporary Methodology. The reporting entity is permitted to temporarily modify the emissions or product data monitoring or calculation method when necessary for the avoidance of missing data or to comply with the missing data provisions of this Part. For emissions data, in the event of an unforeseen breakdown in fuel analytical data monitoring equipment or CEMS equipment, the reporting entity must use the procedures in sections 3.1(h) and (i) of this Part, respectively, for seeking approval of interim data collection procedures. For all other instances that temporary methods are used, the department must be notified by the reporting deadline of the following information: a description of the

temporary method, the affected data, and the duration that the temporary method was used. A temporary method may be used for a period not to exceed 365 days unless the method is concurrently or subsequently submitted and approved by the department as a permanent method pursuant to the requirements in subparagraph (i)(1)(ii) or paragraph (2) of this subdivision. A reporting entity must be able to demonstrate during verification that the temporary method provides data accuracy within ±five percent as specified in paragraph (g)(6) of this section. Industrial product data that does not meet the required accuracy specification must be excluded using the procedure in subdivision (h) of this section to avoid an adverse verification statement.

(5) When regulatory changes impose new or revised reporting requirements or calculation methods on a reporting entity, the monitoring and calculation method must be in place on January 1 of the year in which data is first required to be collected pursuant to the reporting requirements.

(j) Changes in Ownership or Operational Control. If a reporting entity undergoes a change of ownership or operational control, the following requirements apply regarding notifications to the department and reporting responsibilities.

(1) Notifications. Prior to the change of ownership or operational control, the previous owner or operator of the reporting entity and the new owner or operator of the reporting entity must provide the following information to the department in a manner and method approved by the department. Required information must be submitted to the electronic address designated by the department.

(i) The previous owner or operator must notify the department via email of the ownership or operational control change including the name of the new owner or operator and the date of the ownership or operational control change.

(ii) The new owner or operator must notify the department via email of the ownership or operational control change, including the following information:

('a') previous owner or operator;

('b') new owner or operator;

('c') date of ownership or operator change; and

('d') name of a new Designated Representative pursuant to section 1.5(b) of this Part for the affected reporting entity's account in the New York State Greenhouse Gas Reporting Tool (NYS e-GGRT) specified in section 1.6 of this Part.

(2) Reporting Responsibilities. Except as specified in subparagraph (iv) of this paragraph, the owner or operator of record at the time of a reporting or verification deadline specified in this Part has the responsibility for complying with the requirements of this Part, including certifying that the emissions data report is accurate and complete, obtaining verification services, and completing verification.

(i) Except as specified in subparagraph (iv) of this paragraph, the owner or operator of record at the time of a reporting deadline is responsible for submitting the emissions data report covering the complete calendar year data.

(ii) Except as specified in subparagraph (iv) of this paragraph, if an ownership change takes place during the calendar year, reported data must not be split or subdivided for the year, based on ownership. A single annual data report must be submitted for the reporting entity by the current owner or operator. This report must represent required data for the entire calendar year.

(iii) Previous owners or operators are required to provide data and records to new owners or operators that are necessary and required for preparing annual emissions data reports required by this Part.

(iv) Fuel suppliers that cease to have reportable emissions as a result of an ownership change that affects supplier operations retain the responsibility for complying with the requirements of this Part, including certifying that the emissions data report is accurate and complete, obtaining verification services, and completing verification, for the emissions from all fuel transactions that occurred prior to the date of the change of ownership.

(k) Addresses. The electronic address designated by the department shall be substituted for the addresses provided in 40 CFR § 98.9 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) and used for any necessary notifications or materials that are not submitted by other means.

253-1.5 Greenhouse Gas Reporting Content

The emission sources specified in section 1.2 of this Part must develop, submit, and certify pursuant to 40 CFR § 98.4(e) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), GHG emissions data reports to the department each year in accord with the following requirements.

(a) General Contents. In addition to the items specified at 40 CFR § 98.3(c) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), each reporting entity must include in the emissions data report the following information:

(1) department identification number, including DECID and/or Public ID;

(2) county;

(3) geographic location;

(4) electricity generating units must also provide Energy Information Administration numbers including ORIS code;

(5) other business entity identifiers as required by the department.

(b) Designated Representative. Each reporting entity must designate a reporting representative and adhere to the requirements of 40 CFR § 98.4 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) for this representative and for any named alternate designated representatives. In addition to the text specified at 40 CFR § 98.4(e)(1) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), the certification statement signed by the designated representative, or any alternate designated representative must certify that the department or an authorized representative shall be allowed upon presentation of credentials and other documents as may be required by law to:

(1) enter upon the reporting entity's premises where a facility subject to the reporting requirements of this Part, is located or emissions-related activity is conducted, or where records subject to the reporting requirements of this Part;

(2) have access to and copy, at reasonable times, any records subject to the reporting requirements of this Part;

(3) inspect at reasonable times any emission sources, equipment (including monitoring and emission control equipment), practices, and operations regulated or required

pursuant to this Part; and

(4) sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the requirements of this Part.

(c) Corporate Parent, NAICS Codes, and Cogeneration. Each reporting entity must submit information to meet the requirements specified in 40 CFR §§ 98.3(c)(10), (c)(11) and (c)(4)(v) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) on Reporting of Corporate Parent Information, NAICS Codes and Cogeneration.

(d) Facility Level Energy Input and Output. The reporting entity must include in the emissions data report information about the facility's energy acquisitions and energy provided or sold as specified in this subdivision. For the purpose of reporting under this subdivision, the reporting entity may exclude any electricity that is generated outside the facility and delivered into the facility with final destination outside of the facility. The reporting entity may also exclude electricity consumed by operations or activities that do not generate any emissions, energy outputs, or products that are covered by this Part and that are neither a part of nor in support of electricity generation or any industrial activities covered by this Part. The reporting entity must report this information for the calendar year covered by the emissions data report, pro-rating purchases as necessary to include information for the full months of January and December.

(1) Electricity purchases or acquisition from sources outside of the facility boundary (MWh) and the name and department identification number of each electricity provider, as applicable.

(2) Facilities with a NAICS code listed in Table 2-9 in section 2.22 of this Part

must report the MWh from each electrical distribution utility that provides transmission and/or distribution service and the MWh from each electricity generation provider.

(3) Thermal energy purchases or acquisitions from sources outside of the facility boundary (MMBtu) and the name and department identification number of each energy provider, as applicable. If the operator acquires thermal energy from a PURPA Qualifying Facility and vents, radiates, wastes, or discharges more than 10 percent of the acquired thermal energy before using the energy in any industrial process, operation, or heating/cooling application, the reporting entity must report the amount of thermal energy actually needed and used, in addition to the amount of thermal energy received from the provider.

(4) Electricity provided or sold, as specified in section 2.5(a)(4) of this Part, if applicable.

(5) Thermal energy provided or sold to entities outside of the facility boundary: the reporting entity must report the amount of thermal energy provided or sold (MMBtu), the names and department identification number of each end-user as applicable, and the type of unit that generates the thermal energy. If section 2.5 of this Part applies to the operator, the reporting entity must follow the requirements of section 2.5(a)(5) in reporting the thermal energy generated by cogeneration or bigeneration units, and, if applicable, also separately report the information required in paragraph (4) of this subdivision for the thermal energy provided or sold that is not generated by cogeneration or bigeneration units.

(6) If the facility boundary includes more than one cogeneration system, boiler, or steam generator, and each unit/system or each group of units produces thermal energy for

different particular end-users or on-site industrial processes and operations, the reporting entity must report the disposition of generated thermal energy by unit/system or by group of units with the same dispositions, and by the type of thermal energy product provided.

(e) Increases and Decreases in Facility Emissions. The operator of a facility that meets the thresholds in section 1.2(f) of this Part must include the following information in the emissions data report:

(1) Whether a change in the facility's operations or status resulted in an increase or decrease of more than five percent in emissions of greenhouse gases in relation to the previous emission year.

(2) If there is an increase or decrease of more than five percent in emissions of greenhouse gases in relation to the previous year, the operator must provide a brief narrative description of what caused the increase or decrease in emissions. Include in this description any changes in air permit status.

(3) Verifiers must ensure the information reported pursuant to paragraph (1) of this subdivision is reported in conformance with this Part. Paragraph (2) of this subdivision, the narrative description, is not subject to the third-party verification requirements of this Part.

(f) Prohibited Submissions. No person shall submit any record, information, or report required by this Part that:

(1) falsifies, conceals, or covers up by any trick, scheme or device a material fact;

(2) makes any false, fictitious or fraudulent statement or representation;

(3) makes or uses any false writing or document knowing the same to contain

any false, fictitious or fraudulent statement or entry; or

(4) omits material facts from a submittal or record.

(g) Computation of Time.

(1) Unless otherwise stated, any time period scheduled under this Part to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(2) Unless otherwise stated, any time period scheduled under this Part to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(h) Holidays and Weekends. Unless otherwise stated, if the final day of any time period under this Part falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

253-1.6 Reporting Mechanism

Reporting Entities shall submit emissions data reports and any revisions to the reports through the NYS e-GGRT, or any other reporting tool approved by the department that will guarantee transmittal and receipt of data required by this Part.

253-1.7 Record Keeping

Each emission source that is required to report greenhouse gases under this Part must keep records as required by 40 CFR § 98.3(g) through (h) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) and as specified in this Subpart or as prescribed in the relevant section of Subpart 2 of this Part.

(a) Duration.

(1) Large emission sources as specified in section 1.2(f) of this Part, in any reporting year, must maintain all records specified in 40 CFR § 98.3(g) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), and records associated with revisions to emissions data reports as provided under 40 CFR § 98.3(h) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), for a period of 10 years from the date of emissions data report certification.

(2) An emission source that is required under Subpart 4 of this Part to verify its emissions must maintain all records for a period of 10 years from the date of emissions data report certification.

(3) Emission sources that do not meet the threshold requirements pursuant to section 1.2(f) of this Part or are not required to verify their emissions pursuant to Subpart 4 of this Part during any reporting year, must maintain required records for a period of five years from the date of certification.

(4) Large emission sources as specified in section 1.2(f) of this Part that fully exit reporting pursuant to section 1.2(n)(1) of this Part must maintain the corresponding records required under this section and retain such records for 10 years following the submission of the final emissions data report to the department.

(b) Requests for Records. Copies of any records or other materials maintained under the requirements of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) or this Part must be made available to the department upon request within 14 days of receipt of such request by the designated representative of the reporting entity, unless a different schedule is agreed to by the department.

(c) Types of Records to Retain. Emission sources must maintain the following records, including but not limited to:

(1) Information used to quantify or report emissions and product data in the emissions data report, underlying monitoring and metering data, invoices of receipts or deliveries, sales transaction data, calculation methods, protocols used, analysis results, calibration records, electricity transaction data, and other relevant information.

(2) A list of units, operations, processes, and activities for which GHG emissions were calculated.

(3) The data used to calculate the GHG emissions for each unit, operation, process and activity categorized by fuel or material type. These data include but are not limited to:

(i) the GHG emissions calculations and methods used;

(ii) analytical results for the development of site-specific emission factors;

(iii) the results of all required analyses for high heat value, carbon content, and other required fuel or feedstock parameters;

(iv) emissions data and input data, industrial product data and associated inputs; data associated with thermal energy provided, sold, purchased, or acquired; and data associated with electricity provided, sold, purchased, or acquired must be sufficient to allow for verification of each emissions data report; and

(v) any facility operating data or process information used for the GHG calculations.

(4) The annual GHG reports.

(5) Missing data computations for each missing data event, the cause of each event and the corrective actions taken to restore malfunctioning monitoring equipment.

(6) Continuous Monitoring System Records. The results of all required certification and quality assurance tests for continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHG emissions reported under this Part.

(d) Format for Retained Records. When possible, all records shall be kept in readable electronic format and must be recorded in a form that is suitable of expeditious inspection and review. Upon request by the department, the records required under this section must be made available as required in subdivision (b) of this section.

(e) GHG Monitoring Plan. Each facility operator or supplier that reports under section 1.2 of this Part, must complete and retain for review by a verifier or the department a written GHG monitoring plan that meets the requirements of this subdivision. Each facility operator or supplier that meets the thresholds in section 1.2(f) of this Part must submit to the department a GHG monitoring plan by December 31, 2026, or by the end of the first calendar in which the source first meets the thresholds in section 1.2(f) of this Part. Any source that is required to submit a GHG monitoring plan must resubmit that monitoring plan in any year in which a revision is made. Submissions of GHG monitoring plans should be sent to the electronic address designated by the department.

(1) The GHG monitoring plan shall include these elements:

(i) identification of positions of responsibility (i.e., job titles) for collection of the emissions data;

(ii) explanation of the processes and methods used to collect the necessary data for the GHG calculations; and

(iii) description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this Part.

(2) The GHG monitoring plan may rely on references to existing corporate documents provided that the elements of paragraph (1) of this subdivision are clearly recognizable.

(3) The owner or operator of the emission source shall revise the GHG monitoring plan as needed to reflect changes in production processes, monitoring instrumentation, and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime.

(4) Upon request by the department, the owner or operator of the emission source shall make all information that is collected in conformance with the GHG monitoring plan available for review during an audit.

(f) GHG Inventory Program for Electric Power Entities that Import or Export Electricity. In lieu of a GHG Monitoring Plan, electric power entities that import or export electricity must prepare GHG Inventory Program documentation that is maintained and available for department audit pursuant to the recordkeeping requirements of this section. The following information is required:

(1) information to allow the department to develop a general understanding of reporting entity boundaries, operations, and electricity transactions;

(2) reference to management policies or practices applicable to reporting pursuant to section 2.4 of this Part;

(3) list of key personnel involved in compiling data and preparing the emissions data report;

(4) training practices for personnel involved in reporting delivered electricity pursuant to section 2.4 of this Part, and responsible for data report certification, including documented training procedures;

(5) query of NERC e-Tag source data to determine the quantity of electricity (MWh) imported, exported, and wheeled for transactions in which the EPE is the PSE on the last physical path segment that crosses the border of New York, access to review the raw e-Tag data, a tabulated summary, and query description;

(6) reference to other independent or internal data management systems and records, including written power contracts and associated verbal or electronic records, full or partial ownership, invoices, and settlements data used to document whether reported transactions are specified or unspecified;

(7) description of steps taken and calculations made to aggregate data into reporting categories required pursuant to section 2.4 of this Part;

(8) records of preventive and corrective actions taken to address department findings of past nonconformances and material misstatements;

(9) log of emissions data report modifications made after initial certification; and

(10) a written description of an internal audit program that includes emissions data report review and documents ongoing efforts to improve the GHG Inventory Program.

253-1.8 Confidentiality.

(a) Public Information. Emissions data submitted to the department under this Part is public information and shall not be designated as confidential. Data reported to U.S. EPA under 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) which has been released to the public by U.S. EPA shall be considered public information by the department.

(b) Claim of Confidentiality. Any person submitting information to the department pursuant to this Part may claim such information as "confidential" by clearly identifying such information as "confidential." Any claim of confidentiality by a person submitting information must be based on the person's belief that the information marked as confidential is either trade secret or otherwise exempt from public disclosure under the section 87 of the Public Officers Law. All such requests for confidentiality shall be handled in accordance with the procedures specified in section 616.7 of this Title.

253-1.9 Enforcement.

(a) Penalties. Penalties may be assessed for any violation of this Part pursuant to article 71 of the Environmental Conservation Law.

(b) Report Violations. Each day or portion thereof that any report required by this Part remains unsubmitted, is submitted late, or contains information that is incomplete or inaccurate is a single, separate violation. For purposes of this section, “report” means any emissions data report, verification statement, or other document required to be submitted to the department by this Part.

(c) Each metric ton of CO_2e emitted but not reported as required by this Part is a separate violation.

(1) The department will not initiate enforcement action under this section until after any applicable verification deadline for the pertinent report.

(d) Each failure to measure, collect, record, or preserve information in the manner required by this Part constitutes a separate violation, except where the emission source can demonstrate that the failure results solely from maintenance or calibration required by this Part.

(e) Order On Consent. The department may revoke or modify any Order on Consent issued pursuant to this Part as a sanction for a violation of this Part.

(f) The violation of any condition of an Order on Consent that is issued pursuant to this Part is a separate violation.

(g) Any violation of this Part may be enjoined pursuant to article 71 of the Environmental Conservation Law.

(h) Access Rights. The department or an authorized representative shall be allowed upon presentation of credentials and other documents as may be required by law to:

(1) enter upon a reporting entity’s premises where a facility subject to the reporting requirements of this Part is located or emissions-related activity is conducted, or where records subject to the reporting requirements of this Part are kept;

(2) have access to and copy at reasonable times any records subject to the reporting requirements of this Part;

(3) inspect at reasonable times any emission sources, equipment (including monitoring and emission control equipment), practices, and operations regulated or required pursuant to this Part; and

(4) sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the requirements of this Part.

253-1.10 Severability.

Each provision of this Part shall be deemed severable, and in the event that any provision of this Part is held to be invalid, the remainder of this Part shall continue in full force and effect.

253-1.11 Standardized Methods.

(a) Applicable Methods. Entities that are required to report GHG emissions pursuant to this Part must use either those standardized methods and materials listed in 40 CFR § 98.7 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), or another similar method published by an organization listed in 40 CFR § 98.7 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) that is applicable to the analysis being conducted. For gaseous fuels, fuel characteristics may be determined using chromatographic analysis as specified in 40 CFR § 98.34(a)(6) or (b)(4) (Amended April 25, 2024) (see Table 1, section 200.9 of this Title). All methods used must be documented in the GHG Monitoring Plan that is as required by section 1.7(e) of this Part.

(b) Alternative Test Methods. Alternative test methods that are demonstrated to the satisfaction of the department to be equally or more accurate than the methods in subdivision (a) of this section may be used upon written approval by the department.

Subpart 253-2 Requirements for the Mandatory Reporting of Greenhouse Gas Emissions from Specific Types of Facilities, Suppliers, and Entities

253-2.1 Aluminum Production

The operator of a facility who is required to report under section 1.2 of this Part must comply with subpart F of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) in reporting stationary combustion and process emissions and related data from aluminum production to the department, except as otherwise provided in this section.

(a) CO_2, CH_4, and N_2O from Fuel Combustion. Operators must calculate and report fuel high heat value (in units of MMBtu/kg, MMBtu/scf, or MMBtu/gallon for solid, gaseous, or liquid fuels respectively). When calculating GHG emissions from fuel combustion, the operator must use a method in 40 CFR § 98.33(a)(1) to § 98.33(a)(4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) or 40 CFR § 98.33(c) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) as specified by fuel type in section 2.7 of this Part.

(b) Monitoring, Data, and Records. For each emissions calculation method chosen under subdivision (a) of this section, the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR § 98.34-.37 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), except as modified in subdivisions (c) and (d) of this section, and sections 2.7 and 3.1 of this Part.

(c) Missing Data Substitution Procedures. The operator must comply with 40 CFR § 98.65 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) when substituting for missing data, except as otherwise provided in paragraphs (1) through (2) of this subdivision.

(1) To substitute for missing data for emissions reported under section 2.7 of this Part (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 3.1 of this Part.

(2) For each missing value from paste or anode consumption, the operator must apply a substitute value according to the procedures in subparagraphs (i) through (ii) of this paragraph.

(i) If the data capture rate is at least 80 percent for the emission year, the operator must substitute for each missing value according to 40 CFR § 98.65(a) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title).

(ii) If the data capture rate is less than 80 percent for the emission year, the operator must substitute for each missing value with the maximum capacity of the system and the number of days per month.

(3) The operator must document and retain records of the procedure used for

all missing data estimates pursuant to the recordkeeping requirements of section 1.7 of this Part.

(d) Additional Product Data. In addition to the information required by 40 CFR § 98.66 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), the operator must report additional information as follows:

(1) annual production of aluminum products in short tons;

(2) a description of the product(s);

(3) the process used to produce the products, such as prebake or Soderberg electrolysis; and,

(4) if the facility is producing aluminum billets, the operator must report the production of aluminum and aluminum alloy billets in the emission year (short tons); and,

(5) facilities using a CEMS to report emissions from a combined flue stack are required to use the Tier 4 calculation method to report both combustion and total stack emissions under section 2.7 of this Part, pursuant to the provisions of section 2.7(g) of this Part. These facilities are also required to report process emissions under this section. To report process emissions, the operator must subtract the fuel combustion emissions value from the facility's total reported combined stack emissions value in order to calculate the facility's process emissions value, in metric tons, to be reported under this section. The operator must use Equation 2.1-1 as provided in this paragraph to calculate process emissions:

Equation 2.1-1: Eprocess = Etotal – Ecombustion

Where:

Eprocess = The annual process emissions from a facility’s combined flue stack using a CEMS (metric tons)

Etotal = The total annual emissions from a facility’s combined flue stack using a CEMS (metric tons)

Ecombustion = The annual combustion emissions from a facility’s combined flue stack using a CEMS (metric tons)

253-2.2 Anaerobic Digestion and Liquid Storage of Waste

The operator of a facility who is required to report under section 1.2 of this Part and that exceeds an applicability threshold pursuant to subdivision (a) of this section must report annual emissions and other data as specified in this section. Applicable facilities may include anaerobic digesters or reactors and liquid or slurry waste storages that are operated at solid waste management facilities or Concentrated Animal Feeding Operations or CAFO under section 750-1.2(a)(23) of this Title but does not include commercial chemical fertilizers or solid waste landfills.

(a) Applicability.

(1) Operators that treat waste in anaerobic digesters or reactors or store waste that contains degradable organic carbon as a liquid or slurry in storages must comply with the reporting requirements in subdivision (d) of this section if wastes imported to the facility or generated at the facility during the reporting year were in excess of at least one of the

following thresholds.

(i) 1 x 10^6 gallons of aqueous industrial food waste;

(ii) 7 x 10^8 gallons of municipal wastewater;

(iii) 1500 metric tons (wet mass) of food scraps, commercial food waste, or industrial food waste;

(iv) 430 metric tons (dry mass) of food scraps, commercial food waste, or industrial food waste;

(v) 1100 metric tons of stover, yard trimmings, or other plant biomass;

(vi) 1100 metric tons of paper or paper pulp;

(vii) 290 metric tons of fats, oils, or grease;

(viii) 600 metric tons of any other waste that contains degradable organic carbon; or

(ix) a combination of different waste types in amounts such that the following sum exceeds 1: gallons of aqueous industrial wastewater/(1 x 10^6) + gallons of municipal wastewater/(7 x 10^8) + wet metric tons of food waste/1500 + dry metric tons of food waste/430 + metric tons of plant biomass/1100 + metric tons of paper or paper pulp/1100 + metric tons of fats oils or grease/290 + metric tons of other waste that contains degradable organic carbon/600.

(2) Operators may comply with this section by submitting an abbreviated report as set forth in subdivision (b) of this section if either of the following apply during the reporting year:

(i) the facility is a Concentrated Animal Feeding Operations or CAFO under section 750-1.2(a)(23) of this Title with 2500 or fewer mature dairy cows present at any one time; or

(ii) the facility is a Concentrated Animal Feeding Operations or CAFO under section 750-1.2(a)(23) of this Title with more than 2500 mature dairy cows present at any one time, the facility imports less than 50 percent of any of the waste thresholds in paragraph (1) of this subdivision, and the facility does not heat waste in liquid or slurry storages or anaerobic digesters or reactors using fossil fuels.

(b) Abbreviated reporting. Abbreviated reports submitted by facilities that meet the criteria in paragraph (a)(2) of this section must include the following information for each liquid or slurry storage or anaerobic digester:

(1) the construction years and locations (decimal degrees longitude and latitude);

(2) operational volumes (gallons);

(3) the total amounts of waste (gallons) stored or treated;

(4) average solids and hydraulic retention times (days);

(5) whether flares or storage covers are used; and

(6) whether fossil fuels are consumed to assist in on-site biogas generation or combustion.

(c) Additional Emissions Data Collection. Operators that exceed the applicability threshold under section 2.20(a) of this Part are required to complete an Emissions Monitoring and Measurement Plan and report pursuant to section 2.20(a) of this Part in addition to the reporting requirements in this section.

(d) Reporting Requirements. Operators subject to reporting requirements under paragraph (a)(1) of this section must provide an annual report of the following operational information and activity data to the department.

(1) Operational information

(i) Annual reports for each anaerobic digester or reactor must include all of the following information:

(‘a’) the year constructed;

(‘b’) the location (decimal degrees latitude and longitude);

(‘c’) the operational volume (gallons);

(‘d’) the carryover masses (kg-dry mass) of grit or fixed solids in the equipment from the previous year; or an average accumulation rate (kg-dry mass/month) of grit or fixed solids which is defined as the mass (kg-dry mass) of these materials removed from the digester during the most recent clean out divided by the amount of time in months since the previous clean out;

(‘e’) the total volume (gallons) of material treated in the equipment during the reporting year;

(‘f’) the total volume (gallons) and source (e.g., stormwater, alley wash water) of water added to waste prior to treatment in the equipment during the reporting year;

(‘g’) dates during the reporting year when waste was not present in the equipment (e.g., during clean outs or repairs);

(‘h’) the approximate residual volume (gallons) of waste retained in the equipment after routine emptying;

('i') the type and number of any operational CH_4 destruction devices connected to the equipment and their respective installation date(s) or most recent replacement date(s);

('j') the type and number of vents to the atmosphere, open-ended valves or lines, and pressure relief valves or devices that are connected to the equipment;

('k') the range of internal operating temperatures (°C);

('l') the type and number of boilers or other heaters used to raise or maintain the internal operating temperature of the anaerobic equipment. Identify the fuel type consumed by each heater (e.g., natural gas, propane, biogas, etc.);

('m') any method(s) used to dewater digestate after anaerobic treatment (e.g., none, sedimentation or settling, centrifuge, hydrocyclone, roller drum, belt press/screen, screw press, stationary screen, vibrating screen, rotating screen);

('n') if dewatering of digestate occurs, the approximate percent moisture of the dewatered digestate, where percent moisture = (1-dry mass/mass before drying) x 100%;

('o') the total volume (gallons) of any liquid extracted by dewatering digestate;

('p') the average and maximum amount of time (days or hours) between the exit of digestate from the anaerobic equipment and dewatering the digestate, if applicable;

('q') the approximate percentage by volume of digestate that undergoes dewatering during the reporting year (e.g., 0 percent, 50 percent, 100 percent);

('r') whether digestate that exits the digester is open to the atmosphere or held and conveyed in a covered container, building, or pipeline prior to dewatering or final placement;

('s') whether any liquid extracted from the digestate is open to the atmosphere or held and conveyed in a covered container, building, or pipeline prior to subsequent treatment or final placement;

('t') any additional treatment steps other than dewatering that are performed on underwatered digestate;

('u') all final placement location types for underwatered digestate (e.g., landfilling, composting, land application) with the approximate percentages by volume going to each type;

('v') all final placement locations of solids from dewatered digestate (e.g., landfilling, composting, land application);

('w') any additional treatment steps that are performed on any liquid extracted from the digestate;

('x') all final placement locations of any liquid extracted from the digestate (e.g., return to the head of the wastewater treatment facility, wash water); and

('y') any coagulants or flocculants (e.g., ferrous sulfate, ferric sulfate, ferric chloride) that are added to waste prior to or after anaerobic treatment.

(ii) Each annual report that includes a liquid or slurry storage must include all of the following information.

('a') the year constructed;

('b') the location (decimal degrees latitude and longitude);

('c') the operational volume (gallons);

('d') the annual maximum depth (feet) of accumulated liquid or slurry waste in the storage;

('e') whether the storage is covered or uncovered and the cover material type and thickness (cm);

('f') the carryover masses (kg-dry mass) of grit or fixed solids in the storage from the previous year; or an average accumulation rate (kg-dry mass/month) of grit or fixed solids which is defined as the mass (kg-dry mass) of these materials removed from the storage during the most recent clean out divided by the amount of time in months since the previous clean out;

('g') the total volume (gallons) of liquid or slurry waste placed in the storage during the reporting year;

('h') the total volume (gallons) and source (e.g., stormwater, alley wash water) of water added to waste prior to placement in the storage;

('i') dates during the reporting year when waste was not present in the storage (e.g., during clean outs or repairs);

('j') the approximate volume (gallons) of waste retained in the equipment after routine emptying; and

('k') the type and number of any operational CH_4 destruction devices that are connected to covered storages and their respective installation date(s) or most recent replacement date(s);

(‘l’) the type and number of any vents to the atmosphere, open-ended valves or lines, and pressure relief valves or devices that are connected to any covered storages;

(‘m’) whether the stored waste is heated above ambient temperatures;

(‘n’) any method(s) used to dewater waste once it is removed from the storage (e.g., none, sedimentation or settling, belt press/screen);

(‘o’) if dewatering of waste occurs after storage, the approximate percent moisture of the dewatered waste (percent moisture = (1- dry mass/mass before drying) x 100 percent);

(‘p’) the total volume (gallons) of any liquid extracted by dewatering waste after storage;

(‘q’) the approximate percentage by volume of stored waste that undergoes dewatering during the reporting year (e.g., 0 percent, 50 percent, 100 percent);

(‘r’) whether any liquid extracted by dewatering stored waste is held in containers open to the atmosphere or held and conveyed in buildings, covered containers, or pipelines prior to subsequent treatment or final placement;

(‘s’) all final placement locations of undewatered waste after removal from the storage (e.g., landfilling, composting, land application);

(‘t’) all final placement locations of solids that are dewatered after storage (e.g., landfilling, composting, land application);

('u') all final placement locations or types of reuse of any liquid extracted by dewatering waste after storage (e.g., alley wash water);

('v') any additional treatment steps that are performed on any liquid extracted by dewatering waste after storage; and

('w') any coagulants or flocculants (e.g., ferrous sulfate, ferric sulfate, ferric chloride) that are added to waste prior to or after storage.

(2) Activity data

(i) The following methods should be used to report the total mass of nitrogen (N) present in waste that has been treated in each anaerobic digester or reactor during the reporting year.

('a') For waste that is dewatered within two days of exiting the anaerobic digester or reactor, measure the Kjeldahl N (mg N/liter) concentrations of the water extracted from the digestate using methods listed in 40 CFR § 136 table 1B (July 1, 2023) (see Table 1, section 200.9 of this Title). Measurements should be made at a frequency that corresponds to the average hydraulic retention time of the anaerobic digester or reactor, or whenever a batch of digestate has finished reacting and is removed and dewatered. Samples should be taken immediately after dewatering occurs. Calculate and report the total annual mass of N (Total $Mass_{N\_Kjeldahl}$) exiting the anaerobic equipment using Equation 2.2-1 as provided in this clause:

$$\text{Equation 2.2-1: Total } Mass_{N\_Kjeldahl} = \sum Volume_{extracted\ water\_i} \times [N_{Kjeldahl\_i}] \times 1/10^6$$

Where:

Total $Mass_{N\_Kjeldahl}$ = the total annual mass (kg-N) of Kjeldahl N present in water extracted by dewatering digestate immediately after it is removed from anaerobic equipment;

$Volume_{dewater\_i}$ = the ith volume of water (liters) extracted by dewatering a batch of digestate produced during the reporting year; and

$[N_{Kjeldahl\_i}]$ = the concentration of Kjeldahl N (mg N/liter) in the ith volume of water extracted by dewatering digestate immediately after anaerobic treatment during the reporting year.

$1/10^6$ = kg/mg

('b') For waste that is not dewatered within two days of exiting the anaerobic digester or reactor, measure the Kjeldahl N (mg N/liter) concentrations on the undewatered digestate using methods listed in 40 CFR § 136 table 1B (July 1, 2023) (see Table 200.9 of this Title). Measurements should be made at a frequency that corresponds to the average hydraulic retention time of the anaerobic digester or reactor, or whenever a batch of digestate has finished reacting and is removed from the digester or reactor. Samples should be taken immediately after the waste exits the digester or reactor. Calculate and report the total annual mass of N exiting the anaerobic equipment using Equation 2.2-2 as provided in this clause:

$$\text{Equation 2.2-2: Total Mass}_{N\_Kjeldahl} = \sum \text{Volume}_{digestate\_i} \times [N_{Kjeldahl\_i}] \times 1/10^6$$

Where:

Total $Mass_{N\_Kjeldahl}$ = the total annual mass (kg-N) of Kjeldahl N present in undewatered digestate exiting the anaerobic equipment during the reporting year;

$Volume_{digestate\_i}$ = the ith volume (liters) of undewatered digestate produced during the reporting year;

$[N_{Kjeldahl\_i}]$ = the concentration of Kjeldahl N (mg N/liter) in the ith volume of digestate produced during the reporting year; and

$1/10^6$ = kg/mg

(ii) For each anaerobic digester or reactor and liquid or slurry storage that is used to treat animal manure during the reporting year, report the following.

('a') the total number of animals of each type listed in Table 2-1 of this section, whose manure went into that digester, reactor or storage; and

('b') the average masses (lb) of the animals of each type listed in Table 2-1 of this section whose manure went into that digester, reactor, or storage; and

('c') the average number of days' worth of manure that went into that digester, reactor, or storage; and

('d') the estimated fraction of any volatile solids separated from the manure through dewatering or other physical processes before the manure went into the digester, reactor, or storage. This estimated fraction can either be taken from Table 2-2 of this section for the appropriate separation method, or shall be specified by the manufacturer of the solids separation equipment; and

('e') any methods used to dewater manure or remove volatile solids before the manure went into the digester, reactor, or storage.

Table 2-1: Animal Types
Dairy Cows
Dairy Heifers
Dairy Calves
Feedlot Steers
Feedlot Heifers
Market Swine <60 lbs
Market Swine 60-119 lbs
Market Swine 120-179 lbs
Market Swine >180 lbs
Breeding Swine
Feedlot Sheep
Goats
Horses
Hens ≥ 1 year
Pullets
Other Chickens
Broilers
Turkeys

Table 2-2: Solids Separation Processes	Estimated fraction of volatile solids removed
Gravity/sedimentation/settling	0.60
Mechanical:	
Stationary Screen	0.20
Vibrating Screen	0.15
Screw Press	0.25

Centrifuge	0.50
Roller Drum	0.25
Belt Press/Screen	0.50

(iii) For each anaerobic digester or reactor and liquid or slurry storage, report the total annual masses (kg-O_2) of the biochemical oxygen demand (BOD5), chemical oxygen demand (COD), or carbonaceous biochemical oxygen demand (CBOD5) entering the anaerobic equipment in domestic, business, and industrial wastewater streams. Measurements of individual wastewater streams should only be combined with other wastewater measurements that use the same type of oxygen demand measurement method. If measurements of different wastewater streams are made using different types of oxygen demand methods (e.g. BOD5 vs COD) they should be summed separately using the equations as provided in this subparagraph:

Equation 2.2-3: $\text{Total Mass}_{BOD5\_year} = \sum \text{Volume}_i \times BOD_{5\_i} \times 1/10^6$; or

Equation 2.2-4: $\text{Total Mass}_{COD\_year} = \sum \text{Volume}_j \times COD_j \times 1/10^6$; or

Equation 2.2-5: $\text{Total Mass}_{CBOD5\_year} = \sum \text{Volume}_k \times CBOD_{5k} \times 1/10^6$;

Where:

$\text{Total Mass}_{BOD5\_year}$, $\text{Total Mass}_{COD\_year}$, $\text{Total Mass}_{BOD5\_year}$ = the total mass (kg-O_2) of oxygen consumed during microbial respiration or chemical oxidation of organic matter present in wastewater streams treated during the reporting year;

$Volume_i$, $Volume_j$ $Volume_k$ = the volume (liters) of the i^{th}, j^{th}, or k^{th} wastewater streams;

BOD_{5_i} = the 5-day biochemical oxygen demand (mg O_2/liter) of the i^{th} wastewater stream measured using an appropriate method listed in 40 CFR § 136 table 1B (July 1, 2023) (see Table 200.9 of this Title);

COD_j = the chemical oxygen demand (mg O_2/liter) of the j^{th} wastewater stream measured using the appropriate method listed in 40 CFR § 136 table 1B (July 1, 2023) (see Table 200.9 of this Title);

$CBOD_{5\_k}$ = the chemical oxygen demand (mg O_2/liter) of the k^{th} wastewater stream measured using an appropriate method listed in 40 CFR § 136 table 1B (July 1, 2023) (see Table 200.9 of this Title); and

$1/10^6$ = kg/mg.

(iv) For each anaerobic digester or reactor and liquid or slurry waste storage, report the total masses (kg-dry mass or kg-wet mass) and sources of all other degradable organic carbon that is treated or stored during the reporting year and is not reported as animal manure in subparagraph (c)(2)(ii) of this paragraph or as sources of oxygen demand in subparagraph (c)(2)(iii) of this paragraph. This may include but is not limited to food scraps without packaging, food waste with packaging, bedding for animals, stover and other plant biomass, waste generated during ethanol production, yard trimmings, solids from treatment of wastewater from domestic, commercial or industrial sources, waste from industrial food and beverage processing, pulp and paper manufacturing waste, and petroleum refining waste. Waste may be reported as either wet mass (kg-wet mass) or dry mass (kg-dry mass), but wet mass measurements should not be combined with dry mass measurements.

(3) Quantified biogas methane destruction, emission, export, and fossil fuel combustion.

(i) For each anaerobic digester or reactor and covered liquid or slurry storage, it is optional to report the quantified total mass of CH_4 (kg) in generated biogas that is destroyed each year through combustion by flares, thermal oxidizers, boilers, turbines, internal combustion engines, or any other methane destroying units. This requires either continuously monitoring both the CH_4 fraction in the biogas (volume of CH_4 per volume of biogas) and the biogas flow rate, temperature and pressure to each methane destruction device that is connected to the digester, reactor, or covered storage according to clause (c)(3)(i)('a') or ('b') of this subparagraph or continuously monitoring the biogas flow rate and making weekly point measurements of the temperature, pressure, and CH_4 fraction of the biogas on route to each methane destruction device according to clause (c)(3)(i)('c') of this subparagraph.

('a') If a monitoring system fully integrates the flow rate, CH_4 fraction, temperature, and pressure of the biogas into a mass of CH_4 that is destroyed over a period of time, sum these masses over the reporting year and report the annual total mass in kg-CH4. Report the CH_4 destruction efficiency (mass of CH_4 destroyed/total mass of CH_4) of each methane destruction device connected to the digester, reactor, or covered storage. Report the destruction efficiency indicated by the device manufacturer if measurements are not available.

(‘b’) If an integrated monitoring system reports a volume of CH_4 (e.g., liters, cf, m^3) that is destroyed over a period of time, then these volumes may be summed over the reporting year and reported as a total volume of CH_4 along with the system manufacturer’s indicated standard pressure and temperature to which the volume measurements are normalized. Report the CH_4 destruction efficiency (mass of CH_4 destroyed/total mass of CH_4) of each methane destruction device connected to the digester, reactor, or covered storage. Report the destruction efficiency indicated by the device manufacturer if measurements are not available.

(‘c’) If the CH_4 fraction, pressure, and temperature of the biogas are not continuously monitored by an integrated system, and the biogas flow rate to a methane destruction device is continuously monitored, then integrate and report the volume of biogas (e.g., liters, cf, m^3) that is produced each calendar week during the reporting year. Measure and report the temperature, pressure, and CH_4 fraction of the biogas at a location representative of conditions at the flow meter at least once during each calendar week that biogas is generated. If temperature, pressure, and CH_4 fraction measurements are made only once per week, there should be at least three days between consecutive measurements. Indicate whether the biogas flow rate, pressure, temperature, and CH_4 fraction are measured before or after water vapor is stripped out of the biogas. Report the CH_4 destruction efficiency (mass of CH_4 destroyed/total mass of CH_4) of each methane destruction device connected to the digester, reactor, or covered storage. Report the destruction efficiency indicated by the device manufacturer if measurements are not available.

(ii) For each anaerobic digester or reactor and covered liquid or slurry storage, report the number of days during the reporting year that an installed CH_4 destruction device was not operational while waste was present in the digester, reactor, or storage.

(iii) For each anaerobic digester or reactor and covered liquid or slurry storage, it is optional to report the quantified total mass of CH_4 (kg) that is generated in biogas and emitted to the atmosphere through open-ended valves or lines, including unlit flares, using one of the quantification methods indicated in clauses (c)(3)(i)('a'), ('b'), or ('c') of this section.

(iv) For each anaerobic digester or reactor and liquid or slurry storage, report the quantity of natural gas or other fossil fuels that are burned in order to heat or otherwise maintain operation of the digester, reactor, or storage according to section 2.7 of this Part.

(v) For each anaerobic digester or reactor and liquid or slurry storage, report the total volume of biogas (e.g., liters, cf, m^3) or total mass of CH_4 (kg-CH_4) in biogas that is exported from the operation site during the reporting year.

(4) Domestic wastewater treatment operational information. In addition to reporting required under subdivision (c) of this section, for each anaerobic digester that operates at a facility that treats municipal wastewater, report the population currently served by the facility and identify any specific nitrogen removal steps that operate at that facility.

(5) Contact information. Provide the name, title, address, email address, and phone number of a contact person capable of responding to questions about digester, reactor, or storage operations.

(e) Monitoring, Data, and Records. Operators subject to reporting requirements of this section must retain the following records for five years substantiating the volumes and masses of waste that they report.

(1) Invoices, electronic records of transfer, bills of lading, or any other records that can be used to determine or verify imported waste quantities and types.

(2) An electronic record of entities from which waste was received and to which any biogas or products of waste treatment were supplied during the reporting year.

253-2.3 Cement Production.

The operator of a facility who is required to report under section 1.2 of this Part must comply with subpart H of 40 CFR part 98 (Amended April 25, 2024) (see Table 1, section 200.9 of this Title) in reporting annual stationary combustion and process emissions and other data from cement production to the department, except as otherwise provided in this section.

(a) CO_2, CH_4, and N_2O from Fuel Combustion. Operators must calculate and report fuel high heat value (in units of MMBtu/kg, MMBtu/scf, or MMBtu/gallon for solid, gaseous, or liquid fuels respectively). When calculating GHG emissions from fuel combustion, the operator must use a method in 40 CFR § 98.33(a)(1) to § 98.33(a)(4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) as specified by fuel type in section 2.7 of this Part.

(b) Monitoring, Data, and Records. For each emissions calculation method chosen under subdivision (a) of this section, the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR § 98.34 to § 98.37 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), except as modified in subdivisions (c) and(d) of this section and sections 2.7 and 3.1 of this Part.

(c) Missing Data Substitution Procedures. The operator must comply with 40 CFR § 98.85 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) when substituting for missing data, except as otherwise provided in paragraphs (1) through (4) of this subdivision.

(1) To substitute for missing data for emissions reported under section 2.7 of this Part (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 3.1 of this Part.

(2) If data for the carbonate content of clinker or cement kiln dust as required by 40 CFR § 98.83(d) (Amended April 25, 2024) (see Table 1, section 200.9 of this Title) are missing, and a new analysis cannot be undertaken, the operator must apply a substitute value according to the procedures in subparagraphs (i) through (iii) of this paragraph.

(i) If the data capture rate is at least 90 percent for the emission year, the operator must substitute for each missing value using the best available estimate of the parameter, based on all available process data.

(ii) If the data capture rate is at least 80 percent but not at least 90 percent for the emission year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter during the given emission year, as well as the two previous emission years.

(iii) If the data capture rate is less than 80 percent for the emission year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 1.7(a) of this Part.

(3) For each missing value of the monthly raw material consumption or monthly clinker production used to calculate emissions, the operator must apply a substitute value according to subparagraphs (i) and (ii) of this paragraph.

(i) If the data capture rate is at least 80 percent for the emission year, the operator must substitute for each missing value according to 40 CFR § 98.85(c) or 40 CFR § 98.85(d) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), as applicable.

(ii) If the data capture rate is less than 80 percent for the emission year, the operator must substitute for each missing value with the maximum short tons of clinker per day capacity of the system or the maximum short tons per day raw material throughput of the kiln, as applicable, and the number of days per month.

(4) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 1.7 of this Part.

(d) Additional Product Data. In addition to the information required by 40 CFR § 98.86 (Amended April 25, 2024) (see Table 1, section 200.9 of this Title), the operator must report the parameters provided in paragraphs (1) through (4) of this subdivision, whether or not a CEMS is used to measure CO_2 emissions.

(1) Annual quantity clinker produced (short tons).

(2) Annual quantity clinker consumed (short tons).

(3) Annual quantity of limestone and gypsum (including both natural and synthetic gypsum) consumed for blending (short tons).

(4) Annual quantity of cement substitute consumed, by type (short tons). This parameter is not subject to review for material misstatement under the requirements of section 4.2(b)(11) of this Part.

(5) Facilities using a CEMS to report emissions from a combined flue stack are required to use the Tier 4 calculation method to report both combustion and total stack emissions under section 2.7 of this Part, pursuant to the provisions of section 2.7(g) of this Part. These facilities are also required to report process emissions under this section. To report process emissions, the operator must subtract the fuel combustion emissions value from the facility's total reported combined stack emissions value in order to calculate the facility's process emissions value, in metric tons, to be reported under this section. The operator must use Equation 2.3-1 as provided in this paragraph to calculate process emissions:

Equation 2.3-1: $E_{process} = E_{total} - E_{combustion}$

Where:

$E_{process}$ = The annual process emissions from a facility's combined flue stack using a CEMS (metric tons)

E_{total} = The total annual emissions from a facility's combined flue stack using a CEMS (metric tons)

$E_{combustion}$ = The annual combustion emissions from a facility's combined flue stack using a CEMS (metric tons)

253-2.4 Electric Power Entities

An electric power entity that is required to report under section 1.2 of this Part must comply with the following requirements.

(a) General Requirements and Content for GHG Emissions Data Reports for Electricity Importers and Exporters.

(1) Greenhouse Gas Emissions. An electric power entity must report GHG emissions separately for each category of delivered electricity required, in metric tons of CO_2 equivalent (MT of CO_2e), according to the calculation methods in subdivision (b) of this section.

(2) Delivered Electricity. An electric power entity must report imported, exported, and wheeled electricity in MWh disaggregated by first point of receipt (POR) or final point of delivery, as applicable, and must also separately report imported and exported electricity from unspecified sources and from each specified source. Substitute electricity defined pursuant to this Part must be separately reported for each specified source, as applicable. First points of receipt and final points of delivery (POD) must be reported using the standardized code used in NERC e-Tags, as well as the full name of the POR/POD.

(3) Imported Electricity from Unspecified Sources. When reporting imported electricity from unspecified sources, an electric power entity must report for each first point of

receipt the following information:

(i) the amount of electricity from unspecified sources as measured at the first point of delivery in New York; and

(ii) GHG emissions, including those associated with transmission losses, as required in subdivision (b) of this section.

(4) Imported Electricity from Specified Facilities or Units. An electric power entity must report all direct delivery of electricity as from a specified source for facilities or units in which they are a generation providing entity (GPE) or have a written power contract to procure electricity. A GPE must report imported electricity as from a specified source when the importer is a GPE of that facility. When reporting imported electricity from specified facilities or units, the electric power entity must disaggregate electricity deliveries and associated GHG emissions by facility or unit and by first point of receipt, as applicable. The electric power entity must also report total GHG emissions and MWh from specified sources. Seller Warranty: The sale or resale of specified source electricity is permitted among entities on the e-tag market path insofar as each sale or resale is for specified source electricity in which sellers have purchased and sold specified source electricity, such that each seller warrants the sale of specified source electricity from the source through the market path.

(i) Claims of specified sources of imported electricity, defined pursuant to this Part, are calculated pursuant to subdivision (b) of this section, must meet the requirements in subdivision (e) of this section, and must include the following information:

(‘a’) Measured at Busbar. The amount of imported electricity from specified facilities or units as measured at the busbar; and ('b') Not Measured at Busbar. If the amount of imported electricity deliveries from specified facilities or units as measured at the busbar is not provided, report the amount of imported electricity as measured at the first point of delivery in New York, including estimated transmission losses as required in subdivision (b) of this section, and the reason why measurement at the busbar is not known.

(5) Imported Electricity Supplied by Asset-Controlling Suppliers. The reporting entity must separately report imported electricity supplied by asset-controlling suppliers recognized by the department. The reporting entity must:

(i) report the asset-controlling supplier standardized purchasing-selling entity (PSE) acronym or code, full name, and the department identification number;

(ii) report asset-controlling supplier power that was not acquired as specified power, as unspecified power;

(iii) report delivered electricity from asset-controlling suppliers as measured at the first point of delivery in New York; and,

(iv) report GHG emissions calculated pursuant to subdivision (b) of this section, including transmission losses.

(v) tagging ACS Power. To claim power from an asset-controlling supplier, the asset-controlling supplier must be identified on the physical path of the NERC e-Tag as the PSE at the first point of receipt, or in the case of asset controlling suppliers that are exclusive marketers, as the PSE immediately following the associated generation owner.

(6) Exported Electricity. The electric power entity must report exported electricity in MWh and associated GHG emissions in MT of CO_2e for unspecified sources

disaggregated by each final point of delivery outside New York, and for each specified source disaggregated by each final point of delivery outside New York, as well as the following information:

(i) Exported electricity as measured at the last point of delivery located in New York, if known. If unknown, report as measured at the final point of delivery outside New York.

(ii) Do not report estimated transmission losses.

(iii) Report GHG emissions calculated pursuant to subdivision (b) of this section.

(7) Exchange Agreements. The electric power entity must report delivered electricity under power exchange agreements consistent with imported and exported electricity requirements of this section. Electricity delivered into New York under exchange agreements must be reported as imported electricity, and electricity delivered out of New York under exchange agreements must be reported as exported electricity.

(8) Electricity Wheeled Through New York. The electric power entity that is the PSE on the last physical path segment that crosses the border of New York on the NERC e-tag must separately report electricity wheeled through New York, aggregated by first point of receipt, and must exclude wheeled power transactions from reported imports and exports. When reporting electricity wheeled through New York, the electric power entity must include the quantities of electricity wheeled through New York as measured at the first point of delivery inside New York. Only an electric power entity, as defined pursuant to this Part, must report wheeled electricity through New York.

(9) Record Keeping. The electric power entity must retain NERC e-Tags, written power contracts, settlements data, and all other information required to confirm reported electricity procurements and deliveries pursuant to the recordkeeping requirements of section 1.7 of this Part.

(10) Electricity Generating Units and Cogeneration Units in New York. Electric power entities that also operate electricity generating units or cogeneration units located inside New York that meet the applicability requirements of this Part must report GHG emissions to the department under section 2.5 of this Part.

(11) Electricity Generating Units and Cogeneration Units Outside New York. Operators and owners of electricity generating units and cogeneration units located outside New York that elect to report to the department under section 2.5 of this Part must fully comply with the reporting requirements of this Part.

(b) Calculating GHG Emissions.

(1) Calculating GHG Emissions from Unspecified Sources. For electricity from unspecified sources, the electric power entity must calculate the annual CO_2 equivalent mass emissions using Equation 2.4-1 as provided in this paragraph:

Equation 2.4-1: $CO_2e = MWh \times TL\ EF_{unsp}$

Where:

CO_2e = Annual CO_2 equivalent mass emissions from the unspecified electricity deliveries at each point of receipt identified (MT of CO_2e).

MWh = Megawatt-hours of unspecified electricity deliveries at each point of receipt identified.

EF_{unsp} = Default emission factor for unspecified electricity imports.

EF_{unsp} = 0.772 MT of CO_2e/MWh

TL = Transmission loss correction factor.

TL = 1.02 to account for transmission losses between the bus bar and measurement at the first point of receipt in New York.

(2) Calculating GHG Emissions from Specified Facilities or Units. For electricity from specified facilities or units, the electric power entity must calculate emissions using Equation 2.4-2 as provided in this paragraph:

Equation 2.4-2: $CO_2e = MWh \times TL \times EF_{sp}$

Where:

CO_2e = Annual CO_2 equivalent mass emissions from the specified electricity deliveries from each facility or unit claimed (MT of CO_2e).

MWh = Megawatt-hours of specified electricity deliveries from each facility or unit claimed.

EF_{sp} = Facility-specific or unit-specific emission factor and calculated using total emissions and transactions data as described below or published on the department’s website. The emission factor is based on data from the year prior to the reporting year.

TL = Transmission loss correction factor.

TL = 1.02 to account for transmission losses associated with generation outside of NYISO.

TL = 1.0 if the reporting entity provides documentation that demonstrates to the satisfaction of the department that transmission losses (1) have been accounted for, (2) are supported by NYISO, or (3) are compensated by using electricity sourced from within New York.

The department shall calculate facility-specific or unit-specific emission factors and publish them on the department's website using Equation 2.4-3 as provided in this paragraph:

Equation 2.4-3: $EF_{sp} = E_{sp} / EG$

Where:

E_{sp} = CO_2e emissions for a specified facility or unit for the report year (MT of CO_2e).

EG = Net generation from a specified facility or unit for the report year shall be based on data reported to the Energy Information Administration (EIA).

To register a specified unit(s) source of power pursuant to paragraph (e)(1) of this section, the emission source must provide to the department unit-level GHG emissions consistent with the data source requirements of this section and net generation data as reported to the EIA, along with contracts for delivery of power from the specified unit(s) to the reporting entity, and proof of direct delivery of the power by the reporting entity as an import to New York.

(i) For specified facilities or units whose operators are subject to this Part or whose owners or operators voluntarily report under this Part, Esp shall be equal to the sum of CO_2e emissions reported pursuant to section 2.5 of this Part.

(ii) For specified facilities or units whose operators are not subject to reporting under this Part or whose owners or operators do not voluntarily report under this Part, but are subject to the U.S. EPA GHG Mandatory Reporting Regulation 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), Esp shall be based on GHG emissions reported to U.S. EPA pursuant to 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title). For GHG emissions reported to U.S. EPA pursuant to 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), if it is not possible to isolate the emissions that are directly related to electricity production, the department may calculate Esp based on EIA data consistent with Form EIA-923 (2024) (see Table 1, section 200.9 of this Title). Emissions from combustion of biomass-derived fuels will be based on EIA data consistent with Form EIA-923 (2024) (see Table 1, section 200.9 of this Title) until such time the emissions are reported to U.S. EPA.

(iii) For specified facilities or units whose operators are not subject to reporting under this Part or whose owners or operators do not voluntarily report under this

Part, nor are subject to the U.S. EPA GHG Mandatory Reporting Regulation 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), E_{sp} is calculated using heat of combustion data reported to the EIA using Equation 2.4-4 as provided in this subparagraph.

Equation 2.4-4: $E_{sp} = 0.001 \times \Sigma(Q \times EF)$

Where:

0.001 = conversion factor kg to MT

Q = Heat of combustion for each specified fuel type from the specified facility or unit for the report year (MMBtu). For cogeneration, Q is the quantity of fuel allocated to electricity generation consistent with Form EIA-923 reporting (2024) (see Table 1, section 200.9 of this Title). For geothermal electricity, Q is the steam data reported to EIA consistent with Form EIA-923 (2024) (see Table 1, section 200.9 of this Title) (MMBtu).

EF = CO_2e emission factor for the specified fuel type as required by this Part (kg CO_2e /MMBtu). For geothermal electricity, EF shall be reported based on the fuel utilized at the facility and fuel consumed based on the information reported consistent with Form EIA-860 (2017) and EIA-923 (2024) (see Table 1, section 200.9 of this Title).

(iv) Facilities or units will be assigned an emission factor by the department based on the type of fuel combusted or the technology used when a U.S. EPA GHG Report or EIA fuel consumption report not available, including new facilities and facilities located outside the U.S.

(v) Meter Data Requirement. Electric power entities shall retain meter generation data to document that the power claimed by the reporting entity was generated by the facility or unit at the time the power was directly delivered.

(‘a’) A lesser of analysis is applicable to imports from specified sources for which the department has calculated an emission factor of zero, and for imports from a covered renewable energy system as defined in section 66-R of the Public Service Law excluding the following: (1) dynamically tagged power deliveries; (2) nuclear power; (3) asset controlling supplier power; and (4) imports from hydroelectric facilities for which a reporting entity’s share of metered output on an hourly basis is not established by power contract. A lesser of analysis is required pursuant to Equation 2.4-5 as provided in this clause:

Equation 2.4-5: Sum of Lesser of MWh = ΣHM_{sp} min(MG_{sp}*S_{sp}, TG_{sp})

Where:

ΣHM_{sp} = Sum of the Hourly Minimum of MG_{sp} and TG_{sp} (MWh).

MG_{sp} = metered facility or unit net generation (MWh).

S_{sp} = reporting entity’s share of metered output, if applicable.

TG_{sp} = tagged or transmitted energy at the transmission or sub-transmission level imported to New York (MWh).

(‘b’) An EPE may conduct the lesser of analysis voluntarily for those resources excluded in clause (‘a’) of this subparagraph.

(3) Calculating GHG Emissions of Imported Electricity Supplied by Asset-Controlling Suppliers. Based on annual reports submitted to the department pursuant to subdivision (d) of this section, the department will calculate and publish on the department’s website the system emission factor for all asset-controlling suppliers recognized by the department. The reporting entity must calculate emissions for electricity supplied using Equation 2.4-6 as provided in this paragraph:

Equation 2.4-6: $CO_2e = MWh \times TL \times EF_{ACS}$

Where:

CO_2e = Annual CO_2 equivalent mass emissions from the specified electricity deliveries from department-recognized asset-controlling suppliers (MT of CO_2e).

MWh = Megawatt-hours of specified electricity deliveries.

EFACS = Asset-Controlling Supplier system emission factor published on the department’s website (MT CO_2e/MWh). The department will assign the system emission factors for all asset-controlling suppliers based on a previous GHG report submitted to the department pursuant to subdivision (d) of this section. The supplier-specific system emission factor is calculated annually by the department. The calculation is derived from data contained in annual reports submitted pursuant to subdivision (d) of this section. The emission factor is based on data from two years prior to the reporting year.

TL = Transmission loss correction factor.

TL = 1.02 when deliveries are not reported as measured at a first point of receipt located within the balancing authority area of the asset-controlling supplier.

TL = 1.0 when deliveries are reported as measured at a first point of receipt located within the balancing authority area of the asset- controlling supplier.

The department shall calculate the system emission factor for asset-controlling suppliers using Equation 2.4-7 as provided in this paragraph:

Equation 2.4-7: EF_{ACS} = Sum of System Emissions MT of CO_2e / Sum of System MWh Sum of System Emissions, MT of CO_2e = $\Sigma E_{asp} + \Sigma(PE_{sp} * EF_{sp}) + \Sigma(PE_{unsp} * EF_{unsp}) - \Sigma(SE_{sp} * EF_{sp})$ Sum of System MWh = $\Sigma EG_{asp} + \Sigma PE_{sp} + \Sigma PE_{unsp} – \Sigma SE_{sp}$

Where:

ΣE_{asp} = Emissions from Owned Facilities. Sum of CO_2e emissions from each specified facility/unit in the asset-controlling supplier’s fleet, consistent with paragraph (2) of this subdivision (MT of CO_2e).

ΣEG_{asp} = Net Generation from Owned Facilities. Sum of net generation for each specified facility/unit in the asset-controlling supplier’s fleet for the emission year as reported to the department under this Part (MWh).

PE_{sp} = Electricity Purchased from Specified Sources. Amount of electricity purchased wholesale and taken from specified sources by the asset-controlling supplier for the emission year as reported to the department under this Part (MWh).

PE_{unsp} = Electricity Purchased from Unspecified Sources. Amount of electricity purchased wholesale from unspecified sources by the asset-controlling supplier for the emission year as reported to the department under this Part (MWh).

SE_{sp} = Electricity Sold from Specified Sources. Amount of wholesale electricity sold from specified sources by the asset-controlling supplier for the emission year as reported to the department under this Part (MWh).

EF_{sp} = CO_2e emission factor as defined for each specified facility or unit calculated consistent with paragraph (b)(2) of this section (MT CO_2e/MWh).

EF_{unsp} = Default emission factor for unspecified sources calculated consistent with paragraph (b)(1) of this section (MT CO_2e/MWh).

(c) Additional Requirements for Retail Providers. Retail providers must include the following information in the GHG emissions data report for each report year, in addition to the information identified in subdivisions (a), (b) and (g) of this section.

(1) Retail providers must report New York retail sales.

(2) Retail providers may elect to report the subset of retail sales attributed to the electrification of shipping ports, truck stops, and motor vehicles if metering is available to separately track these sales from other retail sales.

(3) For facilities or units located outside of New York that are fully or partially

owned by a retail provider that have GHG emissions greater than the default emission factor for unspecified imported electricity based on the most recent GHG emissions data report submitted to the department or U.S. EPA, the retail provider must include:

(i) information required in paragraph (e)(1) of this section in emission years with no reported imported electricity from the facility or unit;

(ii) the quantity of electricity from the facility or unit sold by the retail provider or on behalf of the retail provider having a final point of delivery outside New York, as measured at the busbar.

(iii) high GHG-Emitting Facilities or Units. For facilities or units that are operated by a retail provider or fully or partially owned by a retail provider and that have emissions greater than the default emission factor for unspecified electricity based on the most recent GHG emissions data report submitted to the department or to U.S.EPA, the retail provider must report the following information:

('a') when the product of net generation (MWh) and ownership share is greater than imported electricity (MWh), emissions associated with electricity not imported into New York must be reported using Equation 2.4-8 as provided in this clause:

Equation 2.4-8: CO_2e not imported = $(EG_{sp} * OS - I_{sp}) * EF_{sp}$.

Where:

EG_{sp} = facility or unit net generation, MWh.

OS = fraction ownership share.

I_{sp} = imported electricity, MWh.

$EF_{sp.}$ = facility or unit-specific emission factor, MT of CO_2e/MWh.

('b') list the replacement generation sources, locations, and whether they are new units when $I_{sp} <$ 90 percent of $EG_{sp}*OS$ and when a facility specified in the previous report year has no imported electricity in the current report year.

(iv) retail providers that report as electricity importers or exporters also must separately report electricity imported from specified and unspecified sources by other electric power entities to serve their load, designating the electricity importer. In addition, all imported electricity transactions documented by NERC e-Tags where the retail provider is the PSE at the sink must be reported.

(d) Additional Requirements for Asset-Controlling Suppliers. Owners or operators of electricity generating facilities or exclusive marketers for certain generating facilities may apply for an asset-controlling supplier designation from the department. Approved asset-controlling suppliers may request that the department calculate a supplier-specific emission factor pursuant to paragraph (b)(3) of this section. To apply for asset-controlling supplier designation, the applicant must:

(1) meet the requirements in this Part, including reporting pursuant to section 2.4 of this Part as applicable for each generating facility or unit in the supplier's fleet;

(2) include in its emissions data report wholesale power purchased and taken (MWh) from specified and unspecified sources and wholesale power sold from specified sources according to the specifications in this section, and as required for the department to

calculate a supplier-specific emission factor;

(3) retain documentation that the power sold by the supplier originated from the supplier's fleet of facilities and either that the fleet is under the supplier's operational control or that the supplier serves as the fleet's exclusive marketer;

(4) provide the supplier-specific department identification number to electric power entities who purchase electricity from the supplier's system.

(5) to apply for and maintain asset-controlling supplier status, the applicant shall submit as part of its emissions data report the following information, annually:

(i) general business information, including applicant's name and contact information;

(ii) list of officer names and titles;

(iii) data requirements under paragraph (b)(3) of this section;

(iv) data requirements under paragraph (e)(1) of this section;

(v) a list and description of electricity generating facilities for which the reporting entity is a generation providing entity pursuant to section 1.3(a) of this Part; and,

(vi) an attestation, in writing and signed by an authorized officer of the applicant, as follows:

"I certify under the laws of New York that I am duly authorized by [name of applicant] to sign this attestation on behalf of [name of applicant], that [name of applicant] meets the definition of an asset-controlling supplier as specified in section 1.3(b) of Part 253 of Title 6 of the New York Codes, Rules and Regulations, and that the information submitted herein is true, accurate, and complete."

(6) Asset-controlling suppliers must annually adhere to all reporting requirements of this Part or be removed from asset-controlling supplier designation.

(e) Requirements for Claims of Specified Sources of Electricity. Each reporting entity claiming specified facilities or units for imported or exported electricity must register its anticipated specified sources with the department pursuant to paragraph (1) of this subdivision by February 1 following each emission year to obtain associated emission factors calculated by the department for use in the emissions data report required to be submitted by June 1 of the same year. If an operator fails to register a specified source by the June 1 reporting deadline specified in section 1.4(d) of this Part, the operator must use the emission factor provided by the department for a specified facility or unit in the emissions data report required to be submitted by June 1 of the same year. Each reporting entity claiming specified facilities or units for imported or exported electricity must also meet requirements pursuant to paragraphs (2) through (5) of this subdivision in the emissions data report.

(1) Registration Information for Specified Sources. The following information is required:

(i) The facility names and, for specification to the unit level, the facility and unit names.

(ii) For sources with a previously assigned department identification number, the department facility or unit identification number or supplier number. For newly specified sources, the department will assign a unique identification number.

(iii) If applicable, the facility and unit identification numbers as used for reporting to the U.S. EPA Acid Rain Program, U.S. EPA pursuant to 40 CFR part 98

(Amended November 18, 2024) (see Table 1, section 200.9 of this Title), U.S. Energy Information Administration, Federal Energy Regulatory Commission's PURPA Qualifying Facility program, New York Public Service Commission, and NYISO, as applicable.

(iv) The physical address of each facility, including jurisdiction.

(v) Provide names of facility owner and operator.

(vi) The percent ownership share and whether the facility or unit is under the electricity importer's operational control.

(vii) Total facility or unit gross and net nameplate capacity when the electricity importer is a GPE.

(viii) Total facility or unit gross and net generation when the electricity importer is a GPE.

(ix) Start date of commercial operation and, when applicable, date of repowering.

(x) GPEs claiming additional capacity at an existing facility must include the implementation date, the expected increase in net generation (MWh), and a description of the actions taken to increase capacity.

(xi) Designate whether the facility or unit is a newly specified source, a continuing specified source, or was a specified source in the previous report year that will not be specified in the current report year.

(xii) Provide the primary technology or fuel type as listed below:

('a') variable renewable resources by type, defined for purposes of this Part as solar, wind, and run-of-river hydroelectricity;

('b') hybrid facilities such as solar thermal;

('c') hydroelectric facilities ≤ 30 MW, not run-of-river;

('d') hydroelectric facilities > 30 MW;

('e') geothermal binary cycle plant or closed loop system;

('f') geothermal steam plant or open loop system;

('g') units combusting biomass-derived fuel, by primary fuel type;

('h') nuclear facilities;

('i') cogeneration by primary fuel type;

('j') fossil sources by primary fuel type;

('k') co-fired fuels;

('l') municipal solid waste combustion;

('m') other.

(2) Emission Factors. The emission factor published on the department's website, calculated by the department according to the methods in subdivision (b) of this section, must be used when reporting GHG emissions for a specified source of electricity.

(3) Delivery Tracking Conditions Required for Specified Electricity Imports. Electricity importers must claim a specified source when the electricity delivery meets any of the criteria for direct delivery of electricity defined pursuant to this Part, and one of the following sets of conditions:

(i) the electricity importer is a GPE; or

(ii) the electricity importer has a written power contract for electricity generated by the facility or unit, subject to meeting all other specified source requirements.

(4) Additional Information for Specified Sources. For each claim to a specified source of electricity, the electricity importer must indicate whether one or more of the following descriptions applies:

(i) deliveries from specified sources previously reported as consumed in New York. Specified source of electricity has been reported in a 2026 emissions data report and is claimed for the current emission year by the same electricity importer, based on a written power contract or status as a GPE in effect prior to January 1, 2026 that remains in effect, or that has been renegotiated for the same facility or generating unit for up to the same share or quantity of net generation within 12 months following prior expiration; or a specified facility for which imported electricity was reported as greater than 80 percent of net generation in the 2026 emission year;

(ii) deliveries from existing federally owned hydroelectricity facilities by exclusive marketers. Electricity from specified federally owned hydroelectricity facility delivered by exclusive marketers;

(iii) deliveries from existing federally owned hydroelectricity facilities allocated by contract. Specified federally owned hydroelectricity source delivered by electricity importers with a written power contract in effect within 12 months after changes in rights due to Federal power allocation or redistribution policies, including acts of Congress, and not related to price bidding, that remains in effect or has been renegotiated for the same facility for up to the same share or quantity of net generation within 12 months following prior contract expiration;

(iv) deliveries from new facilities. Specified source of electricity is first registered pursuant to paragraph (1) of this subdivision and delivered by an electricity importer within 12 months of the start date of commercial operation and the electricity importer making a claim in the current emission year is either a GPE or purchaser of electricity under a written power contract;

(v) deliveries from existing facilities with additional capacity. Specified source of electricity is first registered pursuant to paragraph (e)(1) of this subdivision and delivered by a GPE within 12 months of the start date of an increase in the facility's generating capacity due to increased efficiencies or other capacity increasing actions.

(5) Substitute electricity. Report substitute electricity received from specified and unspecified sources pursuant to the requirements of this section.

253-2.5 Electricity Generation and Cogeneration Units

The operator of a facility who is required to report under section 1.2 of this Part must report as specified below and comply with subpart C of 40 CFR part 98 (Amended May 14, 2024) and subpart D of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), as applicable, in reporting emissions and other data from electricity generating and cogeneration units to the department, except as otherwise provided in this section. Notwithstanding the above, the operator of a facility with total facility nameplate generating capacity of less than 1 MW may elect to follow section 2.7 of this Part in reporting electricity generating units as general combustion sources, in lieu of the requirements of section 2.5 of this Part. If engineering estimation is used to report disposition of generated energy or energy flow data that are not used directly to determine emissions, facility operators must demonstrate accuracy of the chosen engineering estimation method.

(a) Information About the Electricity Generating Facility. Notwithstanding any limitations in 40 CFR part 75 (July 1, 2023) or part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), the operator of an electricity generating facility is required to include in the emissions data report the information listed in this subdivision, unless otherwise specified in subdivisions (e) and (g) of this section for geothermal facilities and facilities with renewable energy generation. Reporting of information specified in paragraphs (4) through (6) of this subdivision is optional for facilities that do not provide or sell any generated energy outside of the facility boundary.

(1) If applicable, facility identification numbers assigned by the New York Public Service Commission, U.S. Energy Information Administration, Federal Energy Regulatory Commission's PURPA Qualifying Facility program, and New York Independent System Operator.

(2) Total facility nameplate generating capacity in megawatts (MW).

(3) Indicate whether the facility is a stand-alone electricity generating facility, an independently operated cogeneration/bigeneration facility co-located with the thermal host, an independently operated and sited cogeneration/bigeneration facility, or an industrial, institutional, commercial facility with electricity generation capacity, as applicable. Also indicate whether the facility is a facility that does not provide any generated energy outside of the facility boundary, as applicable.

(4) The disposition of generated electricity in MWh, reported at the facility-level,

including for each of the following disposition categories, if applicable:

(i) Generated Electricity for Grid. Generated electricity provided or sold to a retail provider or electricity marketer who distributes the electricity over the electric power grid for wholesale or retail customers of the grid. The operator must report the name of the retail provider or electricity marketer.

(ii) Generated Electricity for Other Users. Generated electricity provided or sold directly to particular end-users. A reportable end-user includes any person, under the same or different operational control, that is not a part of the facility. Report each end-user's facility name, NAICS code, and department ID if applicable.

('a') In addition to reporting the overall amount of electricity provided or sold directly to end users, separately quantify and report the subset of generated electricity used to produce cooling energy (e.g., chilled water) to end-users outside of the facility boundary.

(iii) Generated Electricity for On-Site Industrial Applications Not Related to Electricity Generation. If the facility includes industrial processes or operations that are neither in support of nor a part of the power generation system, report the total amount of generated electricity used by those on-site industrial processes or operations.

(iv) In addition to reporting the overall amount of electricity used for on-site industrial applications not related to electricity generation, also separately quantify and report the subset of generated electricity that is used to produce cooling energy used on-site that is neither in support of nor a part of the power generation system.

(v) If the facility includes equipment that uses generated electricity to produce cooling (e.g., absorption chiller) for the sole purpose of maintaining temperature in the electricity generation or cogeneration system, account for such electricity as a part of the difference between gross generation and net generation (parasitic load) pursuant to paragraph (b)(2) of this section.

(vi) If a facility includes more than one electricity generating unit or cogeneration system, and each unit/system or each group of units generate electricity for different particular end-users or retail providers or electricity marketers, the operator must separately report the disposition of generated electricity by unit/system or by group of units. For the purpose of separate reporting of disposition, the operator may group similar units together if the generated electricity from the group of units is provided to the same destination.

(5) The operator of a cogeneration or bigeneration unit must report the disposition of the thermal energy (MMBtu) generated by the cogeneration unit or bigeneration unit ("generated thermal energy"), reported at the facility-level, including for each of the following disposition categories, if applicable:

(i) Generated Thermal Energy for Other Users. Thermal energy provided or sold to particular end-users (as defined in section 1.3 of this Part). A reportable end-user includes any person, under the same or different operational control, that is not a part of the facility. Report each end-user's facility name, NAICS code, department ID if applicable, and the types of thermal energy product provided. Exclude from this quantity the amount of thermal energy that is vented, radiated, wasted, or discharged before the energy is provided to the end-user.

(‘a’) In addition to reporting the overall amount of generated thermal energy for other users, separately quantify and report the subset of generated thermal energy that is used to produce cooling energy (e.g., chilled water) or distilled water for a particular end-user outside of the facility boundary.

(ii) Parasitic Steam Use. Thermal energy used for supporting power production that has been included in the quantity reported under paragraph (b)(3) of this section but that is not accounted for in the quantities reported under subparagraphs (i) and (iii) of this paragraph. This thermal energy quantity must not include steam directly used for power production, such as the steam used to drive a steam turbine generator to generate electricity. Activities for supporting power generation may include steam used for power augmentation, NOx control, sent to a de-aerator, or sent to a cooling tower.

(iii) Generated Thermal Energy for On-Site Industrial Applications Not Related to Electricity Generation. If the facility includes other industrial processes or operations that are neither in support of nor a part of the electricity generation or cogeneration system, report the total amount of generated thermal energy that is used by those on-site industrial processes or operations and heating or cooling applications. Exclude from this quantity the amount of thermal energy that is vented, radiated, wasted, or discharged before it is used at industrial processes or operations. This quantity does not include the amount of thermal energy generated by equipment that is not an integral part of the cogeneration unit.

(‘a’) In addition to reporting the overall amount of thermal energy for on-site industrial applications not related to electricity generation, also separately quantify and report the subset of generated thermal energy that is used on-site to produce cooling energy or distilled water that is neither in support of nor a part of the power generation system.

('b') If the facility includes equipment that uses generated thermal energy to produce cooling (e.g., absorption chiller) for the sole purpose of maintaining temperature in the electricity generation or cogeneration system, follow subparagraph (ii) of this paragraph in reporting such use of generated thermal energy.

('c') If a facility includes more than one cogeneration or bigeneration unit/system, and each unit/system or each group of units generates thermal energy for different particular end-users or on-site industrial processes or operations, the operator must report the disposition of generated thermal energy by unit/system or by group of units with the same dispositions. For the purpose of separate reporting of disposition, the operator may group similar units together if the generated thermal energy from the group of units is provided to the same destination.

(6) For the first year of reporting, operators of cogeneration or bigeneration units must submit a simplified block diagram depicting the following, as applicable: individual equipment included in the generation system (e.g. turbine, engine, boiler, heat recovery steam generator); direction of flows of energy specified in paragraphs (4) through (5) of this subdivision, (b)(2) through (4) and (b)(7) through (8) of this section, with the forms of energy carrier (e.g. steam, water, fuel) labeled; and relative locations of fuel meters and other fuel quantity measurements. If the cogeneration or bigeneration system is modified after the initial submission of the diagram, the operator must resubmit an updated diagram to the

department.

(b) Information About Electricity Generating Units. Notwithstanding any limitations in 40 CFR part 75 (July 1, 2023) or part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), the operator of an electricity generating unit must include in the emissions data report the information listed in this subdivision. For aggregation of electricity generating units, the operator must meet the applicable criteria in 40 CFR § 98.36(c)(1) through (4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), unless otherwise specified in section 2.7(h) of this Part and this subdivision. For an electricity generation system, the operator may aggregate all the units that are integrated into the system for the purpose of reporting data to the department. Operators of 40 CFR part 75 (July 1, 2023) (see Table 1, section 200.9 of this Title) units may also aggregate units to the system level according to this paragraph, notwithstanding the limitation in 40 CFR § 98.36(d)(1)(i) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title). If there is more than one system present at the facility, each system must be reported separately. For electricity generating units that are not part of an integrated generation system, aggregation of electricity generating units is limited to units of the same type, as specified in section 2.7(h) of this Part. Operators of geothermal facilities, hydrogen fuel cells, and renewable electricity generating units must follow subdivisions (e), (f), or (g) of this section, whichever is applicable, instead of subdivision (b) of this section. For bottoming cycle cogeneration units, the operator is not required to report the data specified in paragraphs (4) through (6) of this subdivision except for any fuels combusted for supplemental firing as specified in paragraph (7) of this subdivision.

(1) Basic information about the generating unit, including:

(i) nameplate generating capacity in megawatts (MW);

(ii) prime mover technology;

(iii) for aggregation of units, provide a description of the individual equipment included in the aggregation;

(iv) if the unit generates both electricity and thermal energy, indicate whether the unit is a cogeneration or a bigeneration unit. If the unit is a cogeneration unit, indicate whether it is topping or bottoming cycle.

(2) Net and gross power generated, in megawatt hours (MWh). The difference between net generation and gross generation is the parasitic load of electricity generation or cogeneration. The net generation quantity represents the amount of generated electricity that can be provided to the disposition categories in paragraph (a)(4) of this section.

(3) If the unit is a cogeneration or bigeneration unit, the operator must report the total thermal output (MMBtu), as defined pursuant to this Part, that was generated by the unit and can be potentially used in other industrial operations that are not electricity generation, including thermal energy that is vented, radiated, wasted, or discharged. Exclude from this quantity the heat content of returned condensate and makeup water and steam used to drive a steam turbine generator for electricity generation. The total thermal output quantity represents the amount of generated thermal energy that can be provided to the thermal energy disposition categories in paragraph (a)(5) of this section.

(4) Fuel consumption by fuel type, reported in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone-dry short tons

for biomass-derived solids.

(5) If not already reported under the requirements of 40 CFR § 98.36(b) (Amended May 14, 2024) for subpart C units and 40 CFR § 98.46 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) for subpart D units, the operator must report annual CO_2, CH_4, and N_2O emissions from the unit, expressed in metric tons of each gas.

(6) If used to calculate CO_2 emissions, the operator must report weighted or arithmetic average carbon content and high heat value by fuel type, whichever is used in calculating emissions as specified in 40 CFR § 98.33 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), unless already required to report under 40 CFR § 98.36(e)(2)(ii)(C) and (iv)(C) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title).

(7) For cogeneration systems, where supplemental firing has been applied to support electricity generation or thermal output, report the information in paragraphs (4) through (6) of this subdivision. Indicate by fuel type the portion of the total fuel consumption (MMBtu) that is used for supplemental firing and indicate the purpose of the supplemental firing.

(8) Other Heat Input for Electricity Generation. If the electricity generation unit uses additional heat input that is not already accounted for in paragraphs (4) through (6) of this subdivision (for example, if steam or heat is acquired from outside of the electricity generation system boundary or acquired from another facility for the generation of electricity), report the amount of acquired steam or heat (MMBtu). For bottoming cycle cogeneration units only, also report the input steam to the steam turbine (MMBtu) and the output of the

heat recovery steam generator (MMBtu).

(c) Emissions from Fuel Combustion and Sorbent. When calculating CO_2, CH_4, and N_2O emissions from fuel combustion, the operator who is subject to subpart C of 40 CFR part 98 (Amended May 14, 2024) or subpart D of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) must use a method in 40 CFR § 98.33(a)(1) through (4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) as specified by fuel type in section 2.7 of this Part, except that for CO_2 emissions the operator who is subject to subpart D of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) may elect instead to follow the provisions in 40 CFR § 98.43 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), within the limitations of section 1.4(i) of this Part.

(1) The operator of a Subpart D unit must report emissions from fuels combusted within the emission year but not reported pursuant to 40 CFR part 75 (July 1, 2023) (see Table 1, section 200.9 of this Title) requirements, such as prior to initial provisional or monitoring certification of CEMS. The operator must use a method in 40 CFR § 98.33(a)(1) through (4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) as specified by fuel type in section 2.7 of this Part, or if applicable, according to the limited alternative emissions provisions in section 1.4(e) of this Part.

(2) The operator of a Subpart D unit with contractual deliveries of biomethane or biogas is subject to the requirements in section 4.2(i) of this Part and must follow the procedure in section 2.7(e)(4) through (5) of this Part in calculating emissions from biomethane, biogas, and natural gas.

(3) The operator of a Subpart D unit who reports CO_2 emissions using emission calculation methods specified in 40 CFR part 75 (July 1, 2023) (see Table 1, section 200.9 of this Title), and who operates a unit with a wet flue gas desulfurization system, must indicate the portion of the total reported CO_2 emissions that is generated from sorbent injection for acid gas removal.

(d) Monitoring, Data, and Records. For each emissions calculation method chosen under subdivision (c) of this section, the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR § 98.34-.37 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), except as modified in sections 2.5, 2.7, and 3.1 of this Part.

(e) CO_2 and CH_4 Emissions from Geothermal Facilities. Operators of geothermal generating facilities must report CO_2 and CH_4 emissions from geothermal energy sources, the amount of geothermal steam used (MMBtu) if steam quantity is used in calculating emissions, and applicable requirements in paragraphs (a)(1) through (4) of this section, subparagraphs (b)(1)(i) through (iii) of this section, and paragraph (b)(2) of this section. Operators of geothermal generating facilities must also report whether the source is, (1) a geothermal binary cycle plant or closed loop system, or (2) a geothermal steam plant or open loop system.

The operator must calculate annual emissions of CO_2 and CH_4 from geothermal energy sources using source specific emission factors derived from a measurement plan approved by the department. The operator must submit to the department a measurement plan at least 45 days prior to the first test date. The measurement plan must include testing at least annually, and more frequently as needed. Upon approval of the measurement plan by the department, the test procedures in that plan must be performed as specified in the plan.

(f) Hydrogen Fuel Cells. Operators of stationary hydrogen fuel cell units must include the following information in the annual GHG emissions data report:

(1) basic information about the generating unit specified in paragraphs (b)(1) through (2) of this section;

(2) fuel or feedstock consumption by fuel/feedstock type, reporting in units of million standard cubic feet for gases, gallons for liquids, short tons for non- biomass solids, and bone-dry short tons for biomass-derived solids;

(3) the provider of each fuel or feedstock, and the user's customer account number;

(4) cogeneration information in paragraph (b)(3) of this section, if applicable.

(5) CO_2 emissions from the hydrogen fuel cell, calculated using one of the following methods:

(i) The fuel and feedstock mass balance approach in 40 CFR § 98.163(b) (Amended April 25, 2024) (see Table 1, section 200.9 of this Title). If the fuel's carbon content is not known, the facility operator may use the default carbon content percentage value listed in Table 3-1 of section 3.1(c) of this Part.

(ii) For natural gas and biogas, if the fuel heat input is measured by the facility operator or by the fuel supplier, the operator may use Equation 2.5-1 as provided in this subparagraph to estimate emissions.

Equation 2.5-1: CO_2 (MT/year) = H (MMBtu/year) x EF (kg CO_2/MMBtu) x 0.001 (MT/kg)

Where:

CO_2 = Annual CO_2 emissions from fuel and feedstock consumption (metric tons/year)

H = Total fuel heat input for the year (MMBtu/year)

EF = Default CO_2 emission factor. Use 53.02 kg CO_2/ MMBtu for natural gas. Use 52.07 kg CO_2/MMBtu for biogas.

0.001 = Conversion factor from kg to metric tons.

(iii) For biogas fuels, the facility operator may elect to use the best available estimation and engineering estimation approach to calculate emissions.

(g) On-site Renewable Electricity Generation. The requirements in this subdivision apply to facilities that meet the applicability for reporting under section 1.2 of this Part and are not otherwise exempted from reporting under section 1.2(l) of this Part. If such facility includes non-fuel-based renewable electricity generating units with nameplate generating capacity of greater than 0.5 MW, the operator must report the nameplate generating capacity (MW), gross power generated (MWh) by the non-fuel-based renewable electricity generating units, and the applicable information in subdivision (a) of this section.

For facility operators that do not operate other electricity generating units that are subject to the requirements in subdivisions (a) through (f) of this section, reporting of information specified in subparagraph (a)(4)(iii) of this section and paragraphs (a)(5) through

(6) of this section is optional.

(h) Missing Data Substitution Procedures. To substitute for missing data for emissions reported under this section or section 2.7 of this Part (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 3.1 of this Part. Facilities reporting under 40 CFR part 75 (July 1, 2023) (see Table 1, section 200.9 of this Title) must substitute for missing data under the requirements of that part, as specified in 40 CFR § 98.45 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title).

253-2.6 Electronics Manufacturing

The operator of a facility who is required to report under section 1.2 of this Part must comply with subpart I of 40 CFR part 98 (Amended April 25, 2024) (see Table 1, section 200.9 of this Title) in reporting stationary combustion and process emissions and related data from electronics manufacturing to the department, except as otherwise provided in this section.

(a) CO_2, CH_4, and N_2O from Fuel Combustion. Operators must calculate and report fuel high heat values ((in units of MMBtu/kg, MMBtu/scf, or MMBtu/gallon for solid, gaseous, or liquid fuels respectively). When calculating GHG emissions from fuel combustion, the operator must use a method in 40 CFR § 98.33(a)(1) through (4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) or 40 CFR § 98.33(c) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) as specified by fuel type in section 2.7 of this Part.

(b) Monitoring, Data, and Records. For each emissions calculation method chosen under subdivision (a) of this section, the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR § 98.34-.37 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), except as modified in subdivisions (c) through (d) of this section, and sections 2.7 and 3.1 of this Part.

(c) Missing Data Substitution Procedures. The operator must comply with 40 CFR § 98.95 (Amended April 25, 2024) (see Table 1, section 200.9 of this Title) when estimating missing data, except as otherwise provided in paragraphs (1) through (3) of this subdivision.

(1) To substitute for missing data for emissions reported under section 2.7 of this Part (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 3.1 of this Part.

(2) For each missing value of the use of fluorinated heat transfer fluid, the operator must apply a substitute value according to the procedures in subparagraphs (i) through (ii) of this paragraph.

(i) If the data capture rate is at least 80 percent for the emission year, the operator must substitute for each missing value according to 40 CFR § 98.95(b) (Amended April 25, 2024) (see Table 1, section 200.9 of this Title).

(ii) If the data capture rate is less than 80 percent for the emission year, the operator must substitute for each missing value with the maximum capacity of the system and the number of days per month.

(3) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 1.7 of this

Part.

(d) Additional Product Data. In addition to the information required by 40 CFR § 98.96 (Amended April 25, 2024) (see Table 1, section 200.9 of this Title), the operator must report the additional parameters provided in paragraph (1) of this subdivision.

(1) Facilities using a CEMS to report emissions from a combined flue stack are required to use the Tier 4 calculation method to report both combustion and total stack emissions under section 2.7 of this Part, pursuant to the provisions of section 2.7(g). These facilities are also required to report process emissions under this section. To report process emissions, the operator must subtract the fuel combustion emissions value from the facility's total reported combined stack emissions value in order to calculate the facility's process emissions value, in metric tons, to be reported under this section. The operator must use Equation 2.6-1 as provided in this paragraph to calculate process emissions:

Equation 2.6-1: Eprocess = Etotal – Ecombustion

Where:

Eprocess = The annual process emissions from a facility's combined flue stack using a CEMS (metric tons)

Etotal = The total annual emissions from a facility's combined flue stack using a CEMS (metric tons)

Ecombustion = The annual combustion emissions from a facility's combined flue stack using a CEMS (metric tons)

253-2.7 Facility Fuel Utilization and Combustion Sources

The operator of a facility who is required to report under section 1.2 of this Part must comply with subpart C of 40 CFR part 98 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) in reporting stationary fuel combustion emissions and related data to the department, except as otherwise provided in this section.

(a) CO_2 from Steam Producing Units. The operator of a steam producing unit combusting municipal solid waste or solid biomass fuels may use Equation C-2c of 40 CFR § 98.33(a)(2)(B)(iii) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), unless required to use Tier 3 or 4 by subpart C of 40 CFR part 98 (Amended November 18, 2024) or part 75 (July 1, 2023) (see Table 1, section 200.9 of this Title). Operators of steam producing units combusting fossil-based solid fuels must select applicable Tier 3 or Tier 4 pursuant to subpart C of 40 CFR part 98 (Amended November 18, 2024) or part 75 (July 1, 2023) (see Table 1, section 200.9 of this Title) methods.

(b) CEMS CO_2 Monitoring. Notwithstanding the allowed use of oxygen concentration monitors in 40 CFR § 98.33(a)(4)(iv) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), an operator installing a continuous emissions monitoring system that includes a stack gas volumetric flow rate monitor after January 1, 2026, and who reports CO_2 emissions using this system, must install and use a CO_2 monitor. An operator without a CO_2 monitor who uses a CEMS and O_2 concentrations to calculate and report a unit's CO_2 emissions, and who conducts a RATA for the unit, must at least annually include in the RATA the direct monitoring of CO_2 concentration and flow, and the calculation of CO_2 mass per hour. The operator must retain these results pursuant to the recordkeeping requirements of section 1.7 of this Part and make them available to the department upon request. The requirements of this subdivision do not apply to facilities for which pipeline natural gas is the only fuel consumed.

(c) Choice of Tier for Calculating CO_2 Emissions. Notwithstanding the provisions of 40 CFR § 98.33(b) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), the operator's selection of a method for calculation of CO_2 emissions from combustion sources is subject to the following limitations by fuel type and unit size. The operator is permitted to select a higher tier than that required for the fuel type or unit size as specified in this subdivision.

(1) The operator may select the Tier 1 or Tier 2 calculation method specified in 40 CFR § 98.33(a) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) for any fuel listed in Table 2-3 of this section that is combusted in a unit with a maximum rated heat input capacity of 250 MMBtu/hr or less, subject to the limitation at 40 CFR § 98.33(b)(1)(iv) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title).

(2) The operator may select the Tier 2 calculation method specified in 40 CFR § 98.33(a)(2) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) for natural gas when it is pipeline quality, and for distillate fuels listed in Table 2-3 of this section. Tier 1 may be selected when the fuel supplier is providing pipeline quality natural gas measured in units of therms or million Btu. Equation C-2c of 40 CFR § 98.33(a) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) may be selected for the units specified in subdivision (a) of this section.

(3) The operator may select any calculation method specified in 40 CFR § 98.33(a) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) when calculating emissions that are shown to be limited alternative emissions under section 1.4(e) of this Part, or for a fuel providing less than 10 percent of the annual heat input to a unit with a maximum rated heat input capacity of 250 MMBtu/hr or less, unless not permitted under 40 CFR § 98.33(b) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title).

(4) The operator must use either the Tier 3 or the Tier 4 calculation method specified under 40 CFR § 98.33(a)(3) through (4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) for any other fuel, including non-pipeline quality natural gas and fuel with emissions identified as biomass-derived CO_2, subject to the limitations of 40 CFR § 98.33(b)(4) through (5) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) requiring use of the Tier 4 method. The operator using Tier 3 must determine annual average carbon content with weighted fuel use values, as required by Equation C-2b of 40 CFR § 98.33 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title). When fuel mass or volume is measured by lot, the term "n" in Equation C-2b is substituted as the number of lots received in the year.

(d) Source Test Option for N_2O and CH_4. In lieu of other methods specified in this Part, a facility operator may conduct site-specific source testing to derive emission factors and determine annual emissions of N_2O or CH_4 from any combustion source. Alternatively, the operator may use the results of an applicable test method specified in Title 17, California Code of Regulations, section 95471 (June 17, 2010) (see Table 1, section 200.9 of this Title). For source testing:

(1) The facility operator must submit to the department a test plan at least 45 days prior to the first test date. The test plan must provide for testing at least annually, and more frequently as needed to account for seasonal variations in fuels or processes.

(2) The plan must specify conduct of performance and stack tests consistent with the requirements of approved department or U.S. EPA test methods. Process rates during the test must be determined in a manner that is consistent with the procedures used for GHG report accounting purposes.

(3) Upon approval of the test plan by the department, the test procedures in that plan must be repeated as specified in the plan. The department must be notified at least 10 days in advance of subsequent tests.

(e) Procedures for Biomass CO_2 Determination. Emission sources must use the following procedures when calculating emissions from biomass-derived fuels that are intermixed with fossil fuels:

(1) When combusting municipal solid waste (MSW) or any other fuel for which the biomass fraction is not known, the operator must follow the procedures specified in 40 CFR § 98.33(e)(3) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) to specify a biomass fraction.

(2) For the analysis conducted under the requirements of 40 CFR § 98.34(e) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) for partially biogenic fuels other than MSW, the operator may choose to analyze monthly fuel samples. The operator must collect such samples weekly and combine a portion of each weekly sample to form a monthly composite mixture. The monthly composite mixture must be homogenized and well

mixed prior to withdrawal of a sample for analysis.

(3) When calculating emissions from a biomethane and natural gas mixture using the annual MMBtu of fuel combusted in place of the product of Fuel and HHV in Equation C-2a as described in 40 CFR § 98.33(a)(2) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), the operator must calculate emissions based on contractual deliveries of biomethane subject to the requirements of section 4.2(i) of this Part, using the natural gas emission factor in Equation 2.7-1 as provided in this paragraph:

$$\text{Equation 2.7-1: } E_{biomass} = EF_{natural\ gas} \times MMBTu_{biomethane} \times 0.001$$

Where:

$E_{biomass}$ = The annual biomass CO_2, CH_4 or N_2O emissions from biomethane (metric tons)

$E_{natural\ gas}$ = The annual fossil CO_2, CH_4 or N_2O emissions from natural gas (metric tons)

$EF_{natural\ gas}$ = The natural gas emission factor from tables C-1 and C-2 of 40 CFR part 98 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) (kg/MMBtu)

$MMBtu_{annual}$ = The total delivered MMBtus for the reporting year based on utility bills or meters meeting the accuracy requirements of section 1.4(g) of this Part

$MMBtu_{biomethane}$ = The total biomethane deliveries subject to the requirements of section 4.2(i) of this Part for the reporting year based on contractual deliveries

(4) When calculating emissions from a biomethane and natural gas mixture as described in 40 CFR § 98.33(a)(4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) using a continuous emission monitoring system (CEMS), or when calculating those emissions according to subpart D of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), the reporting entity must calculate the biomethane emissions as described in paragraph (3) of this subdivision, with the remainder of emission being natural gas emissions.

(5) When calculating emissions from a biogas and natural gas mixture using 40 CFR § 98.33(a)(4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) or the carbon content method described in 40 CFR § 98.33(a)(3) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), or when calculating those emissions according to subpart D of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), the reporting entity must calculate biogas emissions using a carbon content method as described in 40 CFR § 98.33(a)(3) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), with the remainder of emissions being natural gas emissions.

(f) Fuel Sampling Frequencies. The operator who collects and analyses fuel samples to conduct the monitoring analyses required under 40 CFR § 98.34 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) must sample at the frequencies specified in that section, except in the following cases.

(1) Natural gas that is outside the range of pipeline quality as defined in section

1.3 of this Part must be sampled and analyzed at least monthly by the reporting entity or the fuel supplier.

(2) Under 40 CFR § 98.34(b)(3)(ii)(E) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), in cases where equipment necessary to perform daily sampling and analysis of carbon content and molecular weight for refinery fuel gas is not in place, such equipment must be installed, and procedures established to implement daily sampling and analysis no later than January 1, 2026.

(3) The operator is estimating CO_2 emissions using a CEMS under 40 CFR § 98.33(a)(4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title).

(g) Fuel Use for CEMS Units. The operator who estimates and reports CO_2 emissions using a CEMS under 40 CFR § 98.33(a)(4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) must also report the quantity of each type of fuel combusted in the unit or group of units (as applicable) during the reporting year, in standard cubic feet for gaseous fuels, gallons for liquid fuels, short tons for solid fuels, bone dry short tons for biomass-derived solids, and high heat value in MMbtus/unit for each quantity of fuel. Fuel use monitoring devices for units covered under this subdivision are exempt from the provisions of section 1.4(g) of this Part.

(h) Additional Reporting Requirements. Facility combustion processes may include but are not limited to furnaces, kilns, generators, boilers, engines, incinerators, combustion turbines, process heaters, or smelters used for producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use. All facilities are required to report individual fuel volumes as required by 40 CFR § 98.36(b) and (c)

(Amended May 14, 2024) (see Table 1, section 200.9 of this Title) under this section for fuel used in combustion processes at the facility, including the following additional information.

(1) Following the reporting requirements set forth by 40 CFR § 98.36 (c)(2)(x) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), the operator must supplementally report annual CO_2 mass emissions from units sharing a common stack or duct.

(2) Facilities using the Tier 4 methodology to report emissions from a combined flue stack must also indicate the use of a CEMS and must report total emissions and combustion emissions in metric tons from the combined stack under this section.

(i) Aggregation of Units. Facility operators may elect to aggregate units according to 40 CFR § 98.36(c) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), except as otherwise provided in this subdivision. Facility operators that are reporting under more than one source category in Subpart 2 of this Part and that elect to follow 40 CFR § 98.36(c)(1), (c)(3), (c)(4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), must not aggregate units that belong to different source categories. For the purpose of unit aggregation, units subject to subpart C of 40 CFR part 98 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) that are associated with one source category must not be grouped with other units associated with another source category, except when 40 CFR § 98.36(c)(2) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) applies. Aggregation of stationary fuel combustion units is limited to units of the same type, where the unit type categories are: boiler, reciprocating internal combustion engine, turbine, process heater, and other (none of the above). When reporting under the provisions of 40 CFR §

98.36(c)(1) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) for an aggregation of units or 40 CFR § 98.36(c)(3) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) for common pipe configurations, the requirements can be met by separately reporting the fuel use by fuel type as a percentage of the aggregated fuel consumption attributed to each individual unit or each group of units of the same type. Units subject to section 2.5 of this Part must use the criteria for aggregation in section 2.5(b). Facility operators that choose to aggregate units according to the common stack provision in 40 CFR § 98.36(c)(2) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) using CEMS may report emissions according to 40 CFR § 98.36(c)(2) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), but they must separately report the fuel use by fuel type as a percentage of the aggregated fuel consumption attributed to each individual unit or each group of units of the same type, such that the grouping of units still meets the limitations for unit aggregation specified elsewhere in this subdivision.

(j) Pilot Lights. The operator must include emissions from pilot lights in the emissions data report. The operator may apply appropriate methods from 40 CFR § 98.33 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) or engineering methods to calculate these emissions when pilot lights are unmetered. Pilot lights fueled from a common fuel source may be aggregated for reporting. Emissions reported from pilot lights may be reported as limited alternative emissions consistent with the requirements of section 1.4(e) of this Part. Pilot lights are not subject to the measurement device calibration requirements of section 1.4 of this Part, but pilot light emissions calculations are subject to verification.

(k) Electricity Generating and Cogeneration Units. The operator of a facility that includes electricity generating and cogeneration units meeting the applicability criteria of section 1.2 of this Part must meet the requirements specified in section 2.5 of this Part.

(l) Fuel Supplier Information. The operator who is reporting emissions from the combustion or use of fuels must report the name(s) of the supplier(s) of fuels to the facility, the operator's fuel supplier customer account number(s), fuels supplier service account identification number(s) or other primary account identifier(s), and the annual MMBtu delivered to each account according to billing statements, and what type of fuel supplier provided the fuel (e.g., a position holder, enterer, intrastate natural gas pipeline operator, ESCO). In the case that the fuel is purchased from a person other than a fuel supplier, the operator must report the supplier's name and customer or service account identification number but may report the annual MMBtu delivered based on the seller's billing statement.

(m) Information on Natural Gas Supplied to Downstream Users. The operator who is reporting emissions from the combustion of natural gas must report whether any of the natural gas reported pursuant to subdivision (l) of this section was supplied to downstream users outside of the operator's facility boundary. If so, the operator must report the name of the facility and the annual MMBtu delivered to each user according to billing statements or financial records.

(n) Procedures for Missing Data. To substitute for missing data for emissions reported under section 2.7 of this Part, the operator must follow the requirements of section 3.1 of this Part.

(o) Upstream Out of State Emissions. Facilities reporting in this section must also estimate CO_2e emissions from fossil fuels for the upstream out-of-state emissions associated with the use of these fuels in New York pursuant to the emission factors specified in section 2.18 of this Part.

(p) Other combustion or fuel utilization sources within a facility boundary. Facility owners or operators must report emissions from the use of fuels purchased or delivered to that facility within the reporting year that have not been reported elsewhere in this section or Subpart. Emissions from the fuel must be reported regardless of the type of process that used the fuel. This includes reporting emissions from emergency generators, non-permanent equipment, non-road equipment, and other mechanisms at the facility, provided the owner or operator of the facility took delivery of the fuel for use onsite.

(1) Fuels purchased at an offsite retail location and used on site are not required to be reported by the facility.

(2) A facility owner or operator may report emissions for this subdivision as the difference between total annual fuel purchases or deliveries in a reporting year and the fuel consumed or used in metered processes or inventoried emission sources at the facility in the same reporting year as reported elsewhere in this section or Subpart.

(q) Facilities reporting in this section may make a demonstration to the department that the fuels or products supplied by a fuel supplier or otherwise utilized at the facility were used to make a durable product which is ultimately not combusted or used as fuel.

(i) Without a demonstration, fuel and products are assumed to be combusted or otherwise emitted as a fugitive or vented emission.

(ii) The demonstration must meet the requirements of the department.

(iii) Facilities making successful demonstrations for quantities of fuel or product determined to be turned into durable products would be required to report the upstream out-of-state emissions associated with the fossil fuels in these products pursuant to section 2.18 of this Part.

Table 2-3: Petroleum Fuels for Which Tier 1 or Tier 2 Calculation Methodologies May Be Used Under Paragraph (c)(1) Of This Section		
Fuel Type	Default High Heat Value	Default CO_2 Emission Factor
	MMBtu/gallon	kg CO_2/MMBtu
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG) *** or Propane	0.092	62.98
Propylene	0.091	65.95
Ethane	0.096	62.64
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73
Natural Gasoline	0.110	66.83
Motor Gasoline (finished)	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22
***Commercially sold as "propane" including grades such as HD5.		

253-2.8 Glass Production

The operator of a facility who is required to report under section 1.2 of this Part must comply with subpart N of 40 CFR part 98 (Amended April 25, 2024) (see Table 1, section

200.9 of this Title) in reporting stationary combustion and process emissions and related data from glass production to the department, except as otherwise provided in this section.

(a) CO_2, CH_4, and N_2O from Fuel Combustion. Operators must calculate and report high heat value (in units of MMBtu/kg, MMBtu/scf, or MMBtu/gallon for solid, gaseous, or liquid fuels respectively). When calculating GHG emissions from fuel combustion, the operator must use a method in 40 CFR § 98.33(a)(1) through (4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) or 40 CFR § 98.33(c) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) as specified by fuel type in section 2.7 of this Part.

(b) Monitoring, Data, and Records. For each emissions calculation method chosen under subdivision (a) of this section, the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR § 98.34-.37 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), except as modified in subdivisions (c) through (d) of this section, and sections 2.7 and 3.1 of this Part.

(c) Missing Data Substitution Procedures. The operator must comply with 40 CFR § 98.145 (Amended April 25, 2024) (see Table 1, section 200.9 of this Title) when estimating missing data, except as otherwise provided in paragraphs (1) through (3) of this subdivision.

(1) To substitute for missing data for emissions reported under section 2.7 of this Part (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 3.1 of this Part.

(2) For each missing value of the monthly amounts of carbonate-based raw materials charged to any continuous glass melting furnace, the operator must apply a

substitute value according to the procedures in subparagraphs (i) through (ii) of this paragraph.

(i) If the data capture rate is at least 80 percent for the emission year, the operator must substitute for each missing value according to 40 CFR § 98.145(a) (Amended April 25, 2024) (see Table 1, section 200.9 of this Title).

(ii) If the data capture rate is less than 80 percent for the emission year, the operator must substitute for each missing value with the maximum short tons per day raw material capacity of the continuous glass melting furnace.

(3) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 1.7 of this Part.

(d) Additional Product Data. In addition to the information required by 40 CFR § 98.146 (Amended April 25, 2024) (see Table 1, section 200.9 of this Title), the operator must report the additional parameters provided in paragraphs (1) through (6) of this subdivision whether or not a CEMS is used to measure CO_2 emissions.

(1) The operator of a flat glass manufacturing facility must report the annual quantity of glass pulled from the melting furnace (short tons).

(2) The operator of a container glass manufacturing facility must report the annual quantity of glass pulled from the melting furnace (short tons).

(3) The operator of a fiberglass manufacturing facility must report the annual quantity of glass pulled from the melting furnace (short tons).

(4) The operator of a specialty glass manufacturing facility must report the

annual quantity of glass pulled from the melting furnace (short tons).

(5) The operator of a glass manufacturing facility must report the cullet ratio used in glass production if applicable (percentage).

(6) Facilities using a CEMS to report emissions from a combined flue stack are required to use the Tier 4 calculation method to report both combustion and total stack emissions under section 2.7 of this Part, pursuant to the provisions of section 2.7(g) of this Part. These facilities are also required to report process emissions under this section. To report process emissions, the operator must subtract the fuel combustion emissions value from the facility's total reported combined stack emissions value in order to calculate the facility's process emissions value, in metric tons, to be reported under this section. The operator must use Equation 2.8-1 as provided in this paragraph to calculate process emissions:

Equation 2.8-1: $E_{process} = E_{total} – E_{combustion}$

Where:

$E_{process}$ = The annual process emissions from a facility's combined flue stack using a CEMS (metric tons)

E_{total} = The total annual emissions from a facility's combined flue stack using a CEMS (metric tons)

$E_{combustion}$ = The annual combustion emissions from a facility's combined flue stack using a CEMS (metric tons)

253-2.9 Hydrogen Production

The operator of a facility who is required to report under section 1.2 of this Part must comply with subpart P of 40 CFR part 98 (Amended April 25, 2024) (see Table 1, section 200.9 of this Title) in reporting emissions and other data from molecular hydrogen production to the department, except as otherwise provided in this section.

(a) Definition of Source Category. This source category is defined consistent with 40 CFR § 98.160(b) through (c) (Amended April 25, 2024) (see Table 1, section 200.9 of this Title). This category is further defined as a hydrogen production source that produces molecular hydrogen whether sold to other entities or consumed on-site.

(b) CO_2, CH_4, and N_2O from Fuel Combustion. Operators must calculate and report fuel high heat value (in units of MMBtu/kg, MMBtu/scf, or MMBtu/gallon for solid, gaseous, or liquid fuels respectively). When calculating GHG emissions from fuel combustion under subpart C as specified at 40 CFR § 98.162(b) through (c) (Amended April 25, 2024) (see Table 1, section 200.9 of this Title), the operator must use a method in 40 CFR § 98.33(a)(1) through (4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) or 40 CFR § 98.33(c) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) as specified by fuel type in section 2.7 of this Part.

(c) Monitoring, Data, and Records. For each emissions calculation method chosen under subdivision (b) of this section, the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34-.37 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), except as modified in subdivision (h) of this section and sections 2.7 and 3.1 of this Part.

(d) CO_2 Emissions from Hydrogen Production Units. When calculating CO_2 emissions from hydrogen production units under the fuel and feedstock material balance approach specified at 40 CFR § 98.163(b) (Amended April 25, 2024) (see Table 1, section 200.9 of this Title), the operator must apply the weighted average carbon content values (the term CC_n in Equations P-1 through P-3) and, for gaseous fuels and feedstocks, the weighted average molecular weight values obtained according to the frequencies specified in paragraph (e)(2) of this section.

(e) Fuel and Feedstock Contents. For each hydrogen production unit, operators must report the following information:

(1) When monitoring GHG emissions with a CEMS as specified in 40 CFR § 98.163(a) (Amended April 25, 2024) (see Table 1, section 200.9 of this Title), the operator must report the monthly carbon content, atomic hydrogen content (excluding hydrogen atoms contained in steam), and molecular hydrogen content for each feedstock. The reported values must be weighted averages from the results of one or more analyses per month.

(2) When monitoring GHG emissions without a CEMS as specified in 40 CFR § 98.163(b) (Amended April 25, 2024) (see Table 1, section 200.9 of this Title), the operator must report the monthly weighted average atomic hydrogen content (excluding hydrogen atoms contained in steam) and weighted average molecular hydrogen content for each feedstock from the results of one or more analyses per month. The operator must also report the monthly carbon content for each fuel and feedstock, and the molecular weight for each gaseous fuel and feedstock as follows:

(i) The reported values must be weighted averages from the results of one or more analyses per month for natural gas or standardized materials specified in Table 2-3 in 253-2.7(q) of this Part.

(ii) The reported values must be weighted averages from the results of daily sampling for each month for nonstandard materials not specified in Table 2-3 in 253-2.7(q) of this Part. For liquid and solid fuels and feedstocks, daily samples may be combined to generate a monthly composite sample for carbon content analysis.

(f) Weighted Average Sampling. Where this section requires sampling of a parameter on a more frequent basis than subpart P of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), the operator or supplier must comply with the following:

(1) The samples must be spaced apart as evenly as possible over time, taking into account the operating schedule of the relevant unit or facility.

(2) The operator or supplier must calculate and report a weighted average of the values derived from the samples by using Equation 2.9-1 as provided in this paragraph:

Equation 2.9-1:

$$V_E = \frac{\sum_{j=1}^{n} (V_j \times M_j)}{\sum_{j=1}^{n} M_j}$$

Where:

VE = The value of the parameter to be reported under subpart P 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) for period E.

j = Each period during period E for which a sample is required by this Part.

N = The number of periods j in period E.

Vj = The value of the sample for period j.

Mj = The mass of the sampled material processed or otherwise used by the relevant unit or facility in period j.

(3) The operator or supplier must keep records of the date and result for each sample or composite sample and mass measurement used in Equation 2.9-1 in paragraph (2) of this subdivision, and of the calculation of each weighted average included in the emissions data report, pursuant to the record keeping requirements of section 1.7 of this Part.

(g) Data Reporting Requirements. When reporting data as specified in 40 CFR § 98.166 (Amended April 25, 2024) (see Table 1, section 200.9 of this Title), the operator must also report the mass of carbon and methane for which GHG emissions are calculated and reported by the facility using other calculation methods provided in this regulation (e.g., carbon in waste diverted to a fuel system or flare, where the CO_2 and CH_4 emissions are calculated and reported using other methods specified in this Part). To avoid double-counting, these emissions must be subtracted from the total facility emissions.

(h) Missing Data Substitution Procedures. The operator must comply with paragraphs

(1) through (2) of this subdivision.

(1) To substitute for missing data for emissions reported under section 2.7 of this Part (stationary combustion units and units using continuous emissions monitoring systems); the operator must follow the requirements of section 3.1 of this Part.

(2) For all other data required for emissions calculations in this section, the operator must follow the requirements of subparagraphs (i) through (iii) of this paragraph.

(i) If the analytical data capture rate is at least 90 percent for the emission year, the operator must substitute for each missing value using the best available estimate of the parameter, based on all available process data.

(ii) If the analytical data capture rate is at least 80 percent but not at least 90 percent for the emission year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter during the given emission year, as well as the two previous emission years.

(iii) If the analytical data capture rate is less than 80 percent for the emission year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 1.7(a) of this Part.

(i) Additional Product Data. Operators must report the total annual mass of on-purpose and by-product gaseous hydrogen produced (metric tons) and total annual mass of liquid hydrogen sold (metric tons). Operators must separately report all gaseous and all liquid hydrogen sold or otherwise transferred (metric tons) to hydrogen vehicle fueling stations and include the name of the purchaser (or receiver) and the quantity sold or transferred to each facility or person.

(j) Hydrogen producers shall use the methodology found in 40 CFR § 98.253(b) (Amended April 25, 2024) (see Table 1, section 200.9 of this Title) to calculate and report CO_2, CH_4, and N_2O emissions from all flaring at their facility, except that emissions from flare pilots shall be included in facility reported emissions.

253-2.10 Iron and Steel Production

The operator of a facility who is required to report under section 1.2 of this Part must comply with subpart Q of 40 CFR part 98 (Amended April 25, 2024) (see Table 1, section 200.9 of this Title) and 40 CFR § 98.180-.188 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) in reporting stationary combustion and process emissions and related data from iron and steel production to the department, except as otherwise provided in this section.

(a) CO_2, CH_4, and N_2O from Fuel Combustion. Operators must calculate and report fuel high heat value (in units of MMBtu/kg, MMBtu/scf, or MMBtu/gallon for solid, gaseous, or liquid fuels respectively). When calculating GHG emissions from fuel combustion at a stationary combustion unit under 40 CFR § 98.172(a) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), the operator must use a method in 40 CFR § 98.33(a)(1) through (4) or 98.33(c) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) as specified by fuel type in section 2.7 of this Part.

(b) Monitoring, Data, and Records. For each emissions calculation method chosen under subdivision (a) of this section, the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR § 98.34-.37 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), except as modified in subdivisions (c) through (d) of this section, section 2.7, and section 3.1 of this Part.

(c) Missing Data Substitution Procedures. The operator must comply with 40 CFR § 98.175 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) when substituting for missing data, except as otherwise provided in paragraphs (1) through (2) of this subdivision.

(1) To substitute for missing data for emissions reported under section 2.7 of this Part (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 3.1 of this Part.

(2) If monthly mass or volume of carbon-containing inputs and outputs are missing when using the carbon mass balance procedure in 40 CFR § 98.173(b)(1) (Amended April 25, 2024) (see Table 1, section 200.9 of this Title), the operator must apply substitute values according to the procedures in subparagraphs (i) through (ii) of this paragraph

(i) If the data capture rate is at least 80 percent for the emission year, the operator must substitute for each missing value based on the best available estimate based on information used for accounting purposes (such as purchase records).

(ii) If the data capture rate is less than 80 percent for the emission year, the operator must substitute for each missing value with the maximum throughput capacity of the system and the number of days per month.

(3) The operator must document and retain records of the procedure used for

all missing data estimates pursuant to the recordkeeping requirements of section 1.7 of this Part.

(d) Additional Product Data. In addition to the information required by 40 CFR § 98.176 (Amended April 25, 2024) (see Table 1, section 200.9 of this Title), the operator must report the additional data as follows:

(1) annual production of iron and steel products in short tons;

(2) a description of the product(s); and,

(3) facilities using a CEMS to report emissions from a combined flue stack are required to use the Tier 4 calculation method to report both combustion and total stack emissions under section 2.7 of this Part, pursuant to the provisions of section 2.7(g). These facilities are also required to report process emissions under this section. To report process emissions, the operator must subtract the fuel combustion emissions value from the facility's total reported combined stack emissions value in order to calculate the facility's process emissions value, in metric tons, to be reported under this section. The operator must use Equation 2.10-1 as provided in this paragraph to calculate process emissions:

Equation 2.10-1: Eprocess = Etotal – Ecombustion

Where:

Eprocess = The annual process emissions from a facility's combined flue stack using a CEMS (metric tons)

Etotal = The total annual emissions from a facility's combined flue stack using a CEMS (metric tons)

Ecombustion = The annual combustion emissions from a facility's combined flue stack using a CEMS (metric tons)

253-2.11 Lead Production

The operator of a facility who is required to report under section 1.2 of this Part must comply with subpart R of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) in reporting stationary combustion and process emissions and related data from lead production to the department, except as otherwise provided in this section.

(a) CO_2, CH_4, and N_2O from Fuel Combustion. Operators must calculate and report fuel high heat value (in units of MMBtu/kg, MMBtu/scf, or MMBtu/gallon for solid, gaseous, or liquid fuels respectively). When calculating GHG emissions from fuel combustion at a stationary combustion unit under 40 CFR § 98.182(d) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), the operator must use a method in 40 CFR § 98.33(a)(1) through (4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) or 40 CFR § 98.33(c) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) as specified by fuel type in section 2.7 of this Part.

(b) Monitoring, Data, and Records. For each emissions calculation method chosen under subdivision (a) of this section, the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34-.37 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), except as modified in subdivisions (c) through (d) of this section, section 2.7, and section 3.1 of this Part.

(c) Missing Data Substitution Procedures. The operator must comply with 40 CFR § 98.185 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) when substituting for missing data, except as otherwise provided in paragraphs (1) through (3) of this subdivision.

(1) To substitute for missing data for emissions reported under section 2.7 of this Part (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 3.1 of this Part.

(2) If the annual mass or carbon content of carbon-containing inputs are missing when using the process emissions calculation procedure in 40 CFR § 98.183(b)(2) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), the operator must apply substitute values according to the procedures in subparagraphs (i) through (ii) of this paragraph.

(i) If the analytical data capture rate is at least 80 percent for the emission year, the operator must substitute for each missing value according to 40 CFR § 98.185(a) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) and the number of days per month.

(ii) If the analytical data capture rate is less than 80 percent for the emission year, the operator must substitute for each missing value with the maximum capacity of the system and the number of days per month.

(3) The operator must document and keep records of the procedures used for

estimating missing data pursuant to the recordkeeping requirements of section 1.7 of this Part.

(d) Additional Product Data. The operator of a lead production, recycling, recovery, or manufacturing facility must report production of lead and lead alloys during the emission year (short tons) as well as the furnace type used in that production.

(1) Facilities using a CEMS to report emissions from a combined flue stack are required to use the Tier 4 calculation method to report both combustion and total stack emissions under section 2.7 of this Part, pursuant to the provisions of section 2.7(g). These facilities are also required to report process emissions under this section. To report process emissions, the operator must subtract the fuel combustion emissions value from the facility's total reported combined stack emissions value in order to calculate the facility's process emissions value, in metric tons, to be reported under this section. The operator must use Equation 2.11-1 as provided in this paragraph to calculate process emissions:

Equation 2.11-1: $E_{process} = E_{total} – E_{combustion}$

Where:

Eprocess = The annual process emissions from a facility's combined flue stack using a CEMS (metric tons)

Etotal = The total annual emissions from a facility's combined flue stack using a CEMS (metric tons)

Ecombustion = The annual combustion emissions from a facility's combined flue stack using a CEMS (metric tons)

253-2.12 Oil and Gas Systems

The operator of a facility who is required to report under section 1.2 of this Part must comply with subpart W of 40 CFR part 98 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) and report GHG emissions to the department, except as otherwise provided in this section.

(a) Facilities must report emissions from onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, onshore natural gas transmission compression, onshore natural gas transmission pipeline, underground gas storage, LNG storage and natural gas distribution segments if emission sources in this section emit collectively 10,000 metric tons CO_2e emissions or more per year.

(b) Facilities must report all emissions from natural gas distribution or natural gas transmission equipment if those facilities also report emissions under sections 2.1 through 2.11 and 2.13 of this Part.

(c) Additional data. In addition to the information required by subpart W of 40 CFR part 98 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) facilities shall supply the information in paragraphs (1) – (4) of this subdivision.

(1) Natural gas distribution facilities shall report county specific data from their service area including:

(i) miles of main and service pipeline by material;

(ii) number and type of customer meters;

(iii) number of metering and regulating stations;

(iv) number of pipeline dig-ins; and

(v) the leak detection rate for customer gas meters inspected by the owner or operator of the natural gas distribution facility, including LDCs or contractors acting on their behalf, during the reporting year. The rate shall be reported as the number of meters that had detectable leaks at the time of inspection divided by the number of meters inspected for leaks, as part of inspection programs or opportunistically.

(2) Natural gas distribution facilities shall report county specific emissions data from their service area including:

(i) Annual CO2 and CH4 emissions, in metric tons for each gas, from customer meters serving each type of customer meter using the following emission factors:

('a') Residential customer meters: 0.01582 scf/meter-hour.

('b') Commercial customer meters: 0.00547 scf/meter-hour.

('c') Industrial customer meters: 0.00547 scf/meter-hour.

(ii) Annual CO2 and CH4 emissions, in metric tons for each gas, from pipeline dig-ins.

(3) Facilities that are subject to Part 203 of this Title and have compliant emissions control mechanisms and reporting requirements must use Part 203 emissions reporting information for CH_4 emissions when reporting emissions under this Part.

(4) Facilities that are subject to Part 203 of this Title shall submit blowdown,

pigging and component data as required under that Part.

253-2.13 Solid Waste Management

The operator of a facility who is required to report under section 1.2 of this Part must comply with subpart HH of 40 CFR part 98 (Amended April 25, 2024) (see Table 1, section 200.9 of this Title) or subpart TT of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) in reporting stationary combustion and waste management emissions to the department, except as otherwise provided in this section.

(a) CH_4 from Municipal Solid Waste Landfills. When calculating CH_4 emissions, the operator must use equation HH-5 with a degradable organic carbon or DOC fraction of 0.22 and a k value of 0.038 for all wastes for all years. Operators of facilities with landfill gas capture systems may subtract the quantity of recovered methane calculated from equation HH-4 for the reporting year.

(b) CH_4 from Industrial Waste Landfills. When calculating CH_4 emissions, the operator must use equation TT-6 of 40 CFR § 98.463(b)(1) (November 29, 2013) (see Table 1, section 200.9 of this Title) using an appropriate DOC and k value for wet climates from table TT-1 of subpart TT of 40 CFR part 98 (December 9, 2016) (see Table 1, section 200.9 of this Title) and may subtract the quantity of recovered methane calculated from equation HH-4 of 40 CFR § 98.343(b)(1) (November 29, 2013) (see Table 1, section 200.9 of this Title).

(c) Stationary Combustion. Operators must calculate and report fuel high heat value (in units of MMBtu/kg, MMBtu/scf, or MMBtu/gallon for solid, gaseous, or liquid fuels respectively). When calculating CO_2, CH_4, and N_2O emissions from fuel, waste, or landfill gas combustion, the operator must use a method in 40 CFR § 98.33(a)(1) through (4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) or 40 CFR § 98.33(c) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) as specified by fuel type in section 2.7 of this Part.

(d) Operators that exceed the applicability threshold under section 2.20(a) of this Part are required to complete an Emissions Measurement and Monitoring Plan and report pursuant to section 2.20(a) of this Part in addition to the reporting requirements in this section. Operators may also apply to use a revised DOC following the solid waste composition verification procedures under section 2.20(b) of this Part.

(e) Monitoring, Data, and Records. For each emissions calculation method chosen under subdivisions (a) through (c) of this section, the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR § 98.340-.348 (Amended April 25, 2024) and 40 CFR § 98.460-.468 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), except as modified in this section, section 2.7, and section 3.1 of this Part.

(f) Missing Data Substitution Procedures. The operator must comply with 40 CFR §§ 98.345 and 98.465 (Amended April 25, 2024) (see Table 1, section 200.9 of this Title) when estimating missing data, except as otherwise provided in paragraph (1) of this subdivision.

(1) To substitute for missing data for emissions reported under section 2.7 of this Part (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 3.1 of this Part.

253-2.14 Suppliers of Agricultural Lime and Fertilizer

Any supplier who is required to report under section 1.2(b)(5) of this Part and that produces fertilizer or agricultural liming material products in New York, or that otherwise supplies fertilizers or agricultural liming material products for the purposes of application to soils in New York, must comply with the reporting requirements in this section.

(a) Distributors of Commercial Fertilizer. Any supplier who is licensed and distributes commercial fertilizer pursuant to Part 153 of Title 1 NYCRR shall report the annual quantity of nitrogen distributed to non-licensed persons and a resulting mass of N_2O emissions that would result from land application in New York, using Equation 2.14-1 as provided in this subdivision.

Equation 2.14-1: $N_2O_{direct\ SN} = (F_{sn} * EF_1) * 44/28$

Where:

$N_2O_{direct\ SN}$ = Annual direct N_2O emissions from commercial fertilizer inputs to managed soils in New York (kg N_2O-N yr^{-1} converted to N_2O)

F_{sn} = Annual amount of commercial fertilizer N supplied to New York (kg N yr^{-1})

EF_1= Emission factor for N_2O emissions from commercial fertilizer inputs to managed soils. Use the default factor of 0.016 kg N_2O-N kg N^{-1}

(b) Distributors of Lime. Any supplier that distributes limestone or dolomite products shall report the annual quantity of each distributed in New York and a resulting mass of CO_2 emissions that would result from land application in New York, using Equation 2.14-2 as provided in this subdivision.

$$\text{Equation 2.14-2: } CO_2\text{-}C = ((M_{Limestone} * EF) + (M_{Dolomite} * EF)) * 44/12$$

Where:

CO_2-C = Annual CO_2 emissions from lime application (metric tons C yr^{-1} converted to CO_2)

M = Annual amount of limestone or dolomite (metric tons yr^{-1})

EF = Emission factor for CO_2 emissions from lime application to managed soils. Use the default factors of 0.12 CO_2-C $CaCO_3$ (for limestone) and 0.13 $CaMg(CO_3)_2$ (for dolomite)

(c) Monitoring, Data, and Records. Suppliers must retain the following records for five years substantiating each of the supplies that they report:

(1) Invoices, an electronic record of transfers, or any other records used to determine or that can verify the quantities reported under subdivisions (a) through (c) of this section.

(2) An electronic record of entities from which supplies were received or that the reporting entity supplied during each reporting year.

(d) Missing Data Substitution Procedures. A complete record of all measured parameters used in tracking lime and fertilizer quantities is required.

253-2.15 Suppliers of Coal

Any coal supplier in New York who is required to report under section 1.2 of this Part, must comply with this section.

(a) Annual GHG emissions shall be reported based on the complete combustion of the coal and the emissions from the upstream out-of-state extraction and transmission of the tons of coal brought into New York for final sale to an end user in New York. These emissions shall be calculated from the high heating value of the coal as specified in subdivision (b) of this section and the emission factors as specified in Table 2-4 of this section (combustion) and Table 2-6 of section 2.18 (upstream out of state) of this Part, using Equation 2.15-1 as provided in this subdivision.

Equation 2.15-1: Emissions = HHV * tons of coal * (combustion EF + upstream EF)

Table 2-4: Coal Combustion Emission Factors	CO_2 Kg/mmbtu	CH_4 g/mmbtu	N_2O g/mmbtu
Anthracite	103.69	11	1.6
Bituminous	93.28	11	1.6
Subbituminous	97.17	11	1.6
Lignite	97.72	11	1.6
Coal Coke	113.67	11	1.6

(1) Fuel suppliers in this section must also estimate CO_2e emissions from fossil fuels for the upstream out of state emissions associated with the use of these fuels in New

York pursuant to the emission factors specified in section 2.18 of this Part.

(2) All fuel suppliers in this section may make a demonstration to the department that the fuels or products supplied to an end user or facility were used to make a durable product which is ultimately not combusted or used a fuel.

(i) Without a demonstration, fuel and products are assumed to be combusted or otherwise emitted as a fugitive or vented emission.

(ii) The demonstration must meet the requirements of the department.

(iii) Fuel suppliers making successful demonstrations for quantities of fuel or product determined to be turned into durable products are required to report the upstream out of state emissions associated with the fossil fuels in these products pursuant to section 18 of this Subpart.

(b) Coal suppliers must determine a monthly weighted average high heating value for each delivery of coal. Multiple deliveries within the same month from the same supply source require only one representative sample.

(1) The high heating value shall be determined using ASTM D5865/D5865M-19, ‘‘Standard Test Method for Gross Calorific Value of Coal and Coke” (2019) (see Table 1, section 200.9 of this Title)

(2) The same supply source shall only apply to coal of the same type (i.e., anthracite, bituminous, sub-bituminous, or lignite)

(3) The coal supplier shall report the supply source information including business address of coal producer, corporation name of coal producer, geographic origin of coal, and point of receipt of coal.

(c) The coal supplier shall maintain records necessary to support the calculation of emissions and records supporting the receipt and sale of coal to a natural person or retail location in New York.

(d) Missing data procedures shall be applied whenever a quality-assured value (e.g., the high heating value) of a required parameter is unavailable.

(1) For each missing value, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the "after" value has not been obtained by the time that the GHG emissions report is due, the coal supplier may use the "before" value for missing data substitution or the best available estimate of the parameter, based on all available process data (e.g., sales or delivery schedule, source of coal). If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(e) The coal supplier shall provide:

(1) the data used to calculate emissions from the utilization of the fuel delivered, transferred, or sold to large emission sources, pursuant to section 1.2(f) of this Part, and other Reporting Entities of this Part that are the end users of this fuel; and

(2) the name(s) of the facility, the customer account number(s), and the annual MMbtu delivered, transferred, or sold to large emission sources, pursuant to section 1.2(f) of this Part, and other Reporting Entities of this Part that are customers or end users of the fuel supplier to the department.

253-2.16 Suppliers of Liquid Fuels and Petroleum Products

Any liquid fuel supplier who is required to report under section 1.2 of this Part must comply with this section.

(a) GHGs to Report.

(1) The CO_2, CO_2 from biomass, CH_4, N_2O, and CO_2e emissions, as described in subdivision (b) of this section, from the affected liquid fuels and petroleum products in Table 2-5 of this section.

(2) The CO_2, CO_2 from biomass, CH_4, N_2O, and CO_2e emissions, as described in subdivision (b) of this section, from the volume of affected liquid fuels and petroleum products diverted to non-New York locations.

(i) Below-the-rack distributors shall report the CO_2, CO_2 from biomass, CH_4, N_2O, and CO_2e emissions, as described in subdivision (b) of this section, from the volumes of affected liquid fuels and petroleum products diverted to non-New York locations or transferred to facilities as reported by below-the-rack distributors that were not the Position Holder or Enterer for the affected liquid fuels before the point of final sale.

(3) The CO_2, CO_2 from biomass, CH_4, N_2O, and CO_2e emissions, as described in subdivision (b) of this section, from affected liquid fuels and petroleum products sold or transferred to large emission sources pursuant to section 1.2(f) of this Part or other Reporting Entities pursuant to this Part.

(4) The CO_2, CO_2 from biomass, CH_4, N_2O, and CO_2e emissions, as described in subdivision (b) of this section, from fuels used for aviation or in ocean going vessel where this can be demonstrated.

(5) Emissions reporting is not required for liquid fuel or petroleum product that is disbursed from a rack in New York that has a final destination outside New York, or for liquid fuels that can be demonstrated to have been previously delivered by a position holder or refiner out of an upstream New York terminal or refinery rack prior to delivery out of a second terminal rack.

(6) The GHG emissions from fuel use at facilities with budget units as described in Part 242 of this Title.

(7) The GHG emissions must be separately reported for each fuel or product component or blendstock of blended fuels or products separately.

(8) All importers of liquefied petroleum gas into New York must record composition, if provided by the supplier, and quantity in barrels, corrected to 60°F, for each shipment received

(b) Calculating GHG emissions.

(1) Liquid fuel and petroleum product suppliers must use Equation 2.16-1 as provided in paragraph (2) of this subdivision, to calculate the GHG emissions, CO_2, CH_4, N_2O of all liquid fuels and petroleum products as described in subdivision (a) of this section, based on the quantity and types of fuels reported as specified in subdivision (d) of this section. For fuels that are blended, emissions must be reported for each individual fuel component separately as listed in Table 2-5 of this section, and not as motor gasoline (finished), biofuel blends, or other similar finished fuel. Emissions from denatured fuel ethanol must be calculated as 100 percent ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported. If a position holder in diesel or biodiesel fuel does not have

sealed or financial transaction meters at the rack, and the position holder is the sole position holder at the terminal, the position holder must calculate emissions based on the delivering person's invoiced volume of fuel or a meter that meets the requirements of section 1.4(g) of this section either at the rack or at a point prior to the fuel going into the terminal storage tanks.

(2) For calculating the emissions from liquefied petroleum gas, or biomass-derived fuels, the GHG emissions from the individual components must be summed. Emission factors must be taken from Table 2-5 of this section.

Equation 2.16-1: $GHGi = Producti * Emission\ Factori$

Where:

GHG_i=annual GHG emissions from product i reported by fuel supplier

$Product_i$ = annual quantity of liquid fuel or petroleum product reported by fuel supplier in an emission year

$Emission\ Factor_i$ = Emission factor for GHG per product as specified in Table 2-5 of this section.

(3) All fuel suppliers in this section must estimate CO_2e emissions using Equation 2.16-2 as provided in this paragraph:

Equation 2.16-2: $CO_2e = \sum_{i=1}^{n} GHGi\ x\ GWP20i$

Where:

CO_2e = Carbon dioxide equivalent, metric tons.

GHG_i = Mass emissions of CO_2, CH_4, N_2O from fuels utilization, metric tons.

$GWP20_i$ = Global warming potential for each GHG as specified inthe CO_2 equivalence definition of this Part.

n = Number of greenhouse gases emitted.

(4) All Position Holders and Enterers must calculate and report the upstream out-of-state emissions for affected liquid fuels or products pursuant to section 2.18 of this Part.

(5) Any fuel supplier intending to develop individualized product emission factors must follow the requirements in 40 CFR § 98.393(f)(2) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title).

(6) All fuel suppliers in this section may make a demonstration to the department that the fuels or products supplied to an end user or facility were used to make a durable product that is ultimately not combusted or used as fuel.

(i) Without a demonstration, fuel and products are assumed to be combusted or otherwise emitted as a fugitive or vented emission.

(ii) The demonstration must meet the requirements of the department. Asphalt shall meet the demonstration requirement by being supplied to an Asphalt Pavement

Manufacturing Plant.

(iii) Fuel suppliers making successful demonstrations for quantities of fuel or product determined to be turned into durable products would be required to report the upstream out-of-state emissions associated with the fossil fuels in these products pursuant to section 2.18 of this Part.

(c) Monitoring and QA/QC Requirements. For the emissions calculation under subdivision (b) of this section, the fuel supplier must meet all the monitoring and QA/QC requirements as specified in 40 CFR § 98.394 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), and the requirements of 40 CFR § 98.3(i) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) as further specified in section 1.4 of this Part and this subdivision.

(1) Position holders are exempt from 40 CFR § 98.3(i) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) calibration requirements except when the position holder and person receiving the fuel have common ownership or are owned by subsidiaries or affiliates of the same company. In such cases the 40 CFR § 98.3(i) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) calibration requirements apply, unless:

(i) the fuel supplier does not operate the fuel billing meter;

(ii) the fuel billing meter is also used by companies that do not share common ownership with the fuel supplier; or

(iii) the fuel billing meter is sealed with a valid seal from the county sealer of weights and measures and the operator has no reason to suspect inaccuracies.

(2) As required by 40 CFR § 98.394(a)(1)(iii) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), for fuels that are liquid at 60°F and one standard atmosphere, the volume reported must be temperature and pressure adjusted to these conditions. For liquefied petroleum gas the volume reported must be temperature-adjusted to 60°F.

(d) Data Reporting Requirements. In addition to reporting the information required in 40 CFR § 98.3(c) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), the following Reporting Entities must also report the information identified below:

(1) New York position holders must report the annual quantity in barrels, as reported by the terminal operator, of each liquid fuel or petroleum product listed in Table 2-5 of this section, that is delivered across the rack in New York, including separately reporting liquid fuel or petroleum product that is disbursed for final sale or to an end user in New York, for which a final destination outside New York has been determined, where liquid fuel use or petroleum product use in exclusively aviation or ocean going vessel can be demonstrated, or for liquid fuel or petroleum product that can be demonstrated to have been previously delivered by a position holder out of an upstream New York terminal rack prior to delivery out of a second terminal rack. Denatured fuel ethanol will be reported with the entire volume as 100 percent ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported.

(2) New York position holders that are also terminal operators must report the annual quantity in barrels delivered across the rack of each liquid fuel or petroleum product listed in Table 2-5 of this section, including separately reporting for fuel or product that is

disbursed for final sale or to an end user in New York, that has a final destination outside New York, where a use in exclusively aviation or ocean going vessel can be demonstrated, or for fossil transportation fuels that can be demonstrated to have been previously delivered by a position holder or refiner out of an upstream New York terminal or refinery rack prior to delivery out of a second terminal rack. Denatured fuel ethanol will be reported with the entire volume as 100 percent ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported. If there is only a single position holder at the terminal and only diesel or biodiesel is being dispensed at the rack, then the position holder must report the annual quantity of fuel using a meter meeting the requirements of section 1.4(g) of this Part, or billing invoices from the person delivering fuel to the terminal.

(3) Enterers delivering liquid fuel or petroleum product for distribution outside the bulk transfer/terminal system must report the annual quantity in barrels, as reported on the bill of lading or other shipping documents of each liquid fuel or petroleum product listed in Table 2-5 of this section that is imported as an affected liquid fuel, including affected liquid fuels when use in aviation or ocean going vessels can be demonstrated, except for fuel for which a final destination outside New York can be demonstrated. The denatured fuel ethanol component of a finished transportation fuel must be reported with the entire denatured ethanol volume as 100 percent ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported. Biodiesel or renewable diesel blends containing no more than one percent petroleum diesel by volume are considered to be 100 percent biodiesel or renewable diesel.

(4) Below the rack distributors must report the affected liquid fuel or petroleum

product received from Position Holders and Enterers by reporting the volume of the fuel received and the previous owner of the fuel. Additionally, below the rack distributors must report to the previous owner any diversion or delivery to a reporting entity of affected liquid fuel.

(5) Upstream out of state emissions and supporting data used by the Position Holder or Enterer shall be shared with subsequent fuel owners if they are a reporting facility or below the rack distributor under this Part.

(6) All liquid fuel suppliers identified in this section must report the total quantity of blendstocks, New York Gasoline, New York diesel fuel, and biodiesel and/or renewable diesel that was imported from outside of New York for use in New York. In addition, for blendstocks imports, the designated percentage of oxygenate must be reported.

(7) Fuel suppliers identified in this section must report the total quantity of biodiesel and/or renewable diesel blended in New York diesel for use in New York.

(8) Fuel suppliers identified in this section must report the total quantity in barrels of each Blendstock, Distillate Fuel Oil, or biomass-derived fuel listed in Table 2-5 of this section that is excluded from emissions reporting due to demonstration of final destination outside New York or use in exclusively aviation or marine applications, or demonstration that the fuel was previously delivered by a position holder or refiner out of an upstream New York terminal or refinery rack prior to delivery out of a second terminal rack.

(9) All importers of liquefied petroleum gas into New York must record composition, if provided by the supplier, and quantity in barrels, corrected to 60°F, for each shipment received.

(10) In addition to the information required in 40 CFR § 98.3(c) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), the importer of liquefied petroleum gas into New York must report the annual quantity of liquefied petroleum gas imported as the total volume in barrels as well as the volume of its individual components for all components listed in table MM-1 of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), if supplied by the producer.

(e) Procedures for Missing Data. For quantities of fuels that are purchased, sold, or transferred in any manner, fuel suppliers must follow the missing data procedures specified in 40 CFR § 98.395 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title). The supplier must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 1.7 of this Part.

(f) The liquid fuel and petroleum products supplier shall provide:

(1) the data used to calculate emissions from the utilization of the fuel delivered, transferred, or sold to large emission sources, pursuant to section 1.2(f) of this Part, and other Reporting Entities of this Part that are the customers or end users of this fuel; and

(2) the name(s) of the facility, the customer account number(s), and the annual MMbtu delivered, transferred, or sold to large emission sources, pursuant to section 1.2(f) of this Part, and other Reporting Entities of this Part that are customers or end users of the fuel supplier to the department.

Table 2-5: Liquid Fuels and Petroleum Products Subject to Reporting Under Section 2.16 of this Part					
Liquid fuels	Density (metric tons/bbl)	Carbon Share (% of Mass)	Emission Factor (Metric tons CO_2/bbl)	Emission Factor (g CH_4/bbl)	Emission Factor (g N_2O/bbl)
CBOB—Summer					
Regular	0.1181	86.66	0.3753	20	20
Midgrade	0.1183	86.63	0.3758	20	20
Premium	0.1185	86.61	0.3763	20	20
CBOB—Winter					
Regular	0.1155	86.50	0.3663	20	20
Midgrade	0.1161	86.55	0.3684	20	20
Premium	0.1167	86.59	0.3705	20	20
RBOB —Summer					
Regular	0.1167	86.13	0.3686	20	20
Midgrade	0.1165	86.07	0.3677	20	20
Premium	0.1164	86.00	0.3670	20	20
RBOB —Winter					
Regular	0.1165	85.05	0.3676	20	20
Midgrade	0.1165	86.06	0.3676	20	20
Premium	0.1166	86.06	0.3679	20	20
Distillate No. 1	0.1346	86.40	0.4264	18	3
Distillate No. 2	0.1342	87.30	0.4296	17	3
Distillate Fuel Oil No. 4	0.1452	86.47	0.4604	18	4
Residual Fuel Oil No. 5	0.1365	85.67	0.4288	18	3
Residual Fuel Oil No. 6	0.1528	84.67	0.4744	19	4
Kerosene-type Jet Fuel	0.1294	86.30	0.4095	17	3
Kerosene	0.1346	86.40	0.4604	17	3
Aviation Gasoline	0.1120	85.00	0.3490	15	3
Special Naphtha	0.1222	84.76	0.3798	16	3
Lubricants	0.1428	85.80	0.4492	18	4
Waxes	0.1285	85.30	0.4019	17	3
Asphalt and Road Oil	0.1634	83.47	0.5001	20	4
Liquefied Petroleum Gas (LPG)	0.0806	81.71	0.241	12	3

Ethane	0.0579	79.89	0.170	8	2
Ethylene	0.0492	85.63	0.154	7	1
Propane	0.0806	81.71	0.241	11	2
Propylene	0.0827	85.63	0.260	11	2
Butane	0.0928	82.66	0.281	13	3
Butylene	0.0972	85.63	0.305	13	3
Isobutane	0.0892	82.66	0.270	13	3
Isobutylene	0.0949	85.63	0.2939	13	3
Pentanes Plus	0.1055	83.63	0.3235	14	3
Ethanol (100%)	0.1267	52.14	0.2422	4	1
Biodiesel (≥99%, methyl ester)	0.1396	77.30	0.3957	6	1
Renewable Diesel (≥99%)	0.1342	87.30	0.4296	17	3
Rendered Animal Fat	0.1333	76.19	0.3724	6	1
Vegetable Oil	0.1460	76.77	0.4110	6	1

253-2.17 Suppliers of Natural Gas, Natural Gas Liquids, Compressed Natural Gas, and Liquified Natural Gas

Any supplier of natural gas or natural gas liquids who is required to report under section 1.2 of this Part must comply with subpart NN of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) in reporting emissions and related data to the department, except as otherwise provided in this section.

(a) GHGs to Report.

(1) In addition to the CO_2 emissions specified under 40 CFR § 98.402(a) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), natural gas liquid fractionators must report the CO_2, CH_4, N_2O, and CO_2e emissions that would result from the use of natural gas, natural gas liquids, or biomethane sold, transferred, or delivered to any end user in New York.

(2) In addition to the CO_2 emissions specified under 40 CFR § 98.402(b)

(Amended November 18, 2024) (see Table 1, section 200.9 of this Title), local distribution companies, energy service companies, interstate pipeline operators, and intrastate pipeline operators must report the CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e emissions from the use of natural gas, natural gas liquids, or biomethane sold, transferred, or delivered to any end-user in New York.

(3) The importer of compressed natural gas or liquefied natural gas into New York must report the CO_2, CH_4, N_2O, and CO_2e emissions that would result from the use of the annual quantity of compressed natural gas, and liquefied natural gas imported into the state, except for products for which a final destination outside New York can be demonstrated.

(4) Operators of facilities that make liquefied natural gas products or compressed natural gas products by liquefying or compressing natural gas received from interstate pipelines must report the CO_2, CH_4, N_2O, and CO_2e emissions that would result from the use of all liquefied natural gas sold or delivered to others, except for product for which a final destination outside New York can be demonstrated.

(b) Calculating GHG Emissions.

(1) Natural gas liquid fractionators must use calculation methodology 2 as specified in 40 CFR § 98.403(a)(2) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) to estimate the CO_2 emissions that would result from the complete combustion of all natural gas liquid products supplied except that table MM-1 of 40 CFR part 98 must be used in place of table NN-2 of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title).

(2) For the calculation of CO_2i in paragraph (6) of this subdivision, local distribution companies must estimate CO_2 emissions at the state border or city gate for pipeline quality natural gas using calculation methodology 1 as specified in 40 CFR § 98.403(a)(1) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), except that the product of HHV and Fuel is replaced by the annual MMBtu of natural gas received.

(3) For the calculation of CO_2j in paragraph (6) of this subdivision, public utility gas corporations and publicly owned natural gas utilities must estimate annual CO_2 emissions from instate receipts of pipeline quality natural gas from other public utility gas corporations, interstate pipelines and intrastate transmission pipelines, and annual CO_2 emissions from all natural gas redelivered to other public utility gas corporations or interstate pipelines. Annual CO_2 emissions from redelivered natural gas to intrastate pipelines or publicly owned natural gas utilities must be estimated only if emissions from the redelivered natural gas equals or exceeds 1,000 MT CO_2e calculated according to paragraph (2) of this subdivision. Emissions are calculated according to Equation NN-3 of 40 CFR § 98.403(b)(1) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) except that CO_2j will be the product of MMBtuTotal and the default emission factor from table NN-1 of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) or the product of MMBtuTotal and the reporter specific emission factor. MMBtuTotal must be calculated using Equation 2.17-1 as provided in this paragraph:

$$\text{Equation 2.17-1: } MMBtu_{Total} = MMBtu_{redelivery} - MMBtu_{receipts}$$

Where:

$MMBtu_{Total}$ = Total annual MMBtu used in equation NN-3

$MMBtu_{redelivery}$ = Total annual MMBtu of natural gas delivered to other companies as specified above

$MMBtu_{receipts}$ = Total annual MMBtu of natural gas received from other companies as specified above

(4) For the calculation of CO_2l in paragraph (6) of this subdivision, emissions from receipts of pipeline quality natural gas from in-state natural gas producers and net volume of pipeline quality natural gas injected into storage are estimated according to Equation NN-5 of 40 CFR § 98.403(b)(3) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) except that CO_2l will be calculated as the product of the net annual MMBtu and a default emission factor from table NN-1 of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) or the product of the net annual MMBtu and a reporter specific emission factor.

(5) Determination of pipeline quality natural gas is based on the annual weighted average HHV, determined according to Equation C-2b of 40 CFR § 98.33(a)(2)(ii)(A) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), for natural gas from a single city gate, storage facility, or connection with an in-state producer, interstate pipeline, intrastate pipeline or local distribution company. If the HHV is outside the range of pipeline quality natural gas, emissions will be calculated using the appropriate subparagraph of subdivision (a) of this section replacing the default emission factor with

either a reporter specific emission factor as calculated in 40 CFR § 98.404(b)(2) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) or one determined as follows:

(i) For natural gas or biomethane with an annual weighted HHV below 970 Btu/scf and not exceeding three percent of total emissions estimated under this section, the local distribution company may use the reporter specific weighted yearly average higher heating value and the default emission factor, or an emission factor as determined in 40 CFR § 98.404(c)(3) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title). If emissions exceed three percent of the total, then the Tier 3 method specified in 40 CFR § 98.33(a)(3)(iii) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) must be used with monthly carbon content samples to calculate the annual emissions from the portion of natural gas that is below 970 Btu/scf.

(ii) For natural gas or biomethane with an annual HHV above 1100 Btu/scf and not exceeding three percent of total emissions estimated under this section, the local distribution company must use the reporter specific weighted yearly average higher heating value and a default emission factor of 54.67 kg CO_2/MMBtu or an emission factor as determined in 40 CFR § 98.404(c)(3) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title). If emissions exceed three percent of the total, then the Tier 3 method specified in 40 CFR § 98.33(a)(3)(iii) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) must be used with monthly carbon content samples to calculate the annual emissions from the portion of natural gas that is above 1100 Btu/scf.

(6) When calculating total CO_2 emissions for New York, use Equation 2.17-2 as provided in this paragraph:

Equation 2.17-2: $CO_2 = \sum CO_{2i} - \sum CO_{2j} - \sum CO_{2l}$

Where:

CO_2 = Total emissions.

CO_{2i} = Emissions from natural gas received at the state border or city gate, calculated pursuant to paragraph (2) of this subdivision.

CO_{2j} = Emissions from natural gas received for redistribution to or received from other natural gas transmission companies, calculated pursuant to paragraph (3) of this subdivision.

CO_{2l} = Emissions from storage and direct deliveries from producers calculated pursuant to paragraph (4) of this subdivision.

(7) Natural gas liquid fractionators, local distribution companies, and energy service companies must estimate and report CH_4 and N_2O emissions using Equation C-8 and table C-2 as described in 40 CFR § 98.33(c)(1) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) for all fuels where annual CO_2 emissions are required to be reported by 40 CFR § 98.406 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) and this section. Local distribution companies must use the annual MMBtu determined in paragraphs (2) through (4) of this subdivision in place of the product of the Fuel and HHV in equation C-8 as described in 40 CFR § 98.33 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) when calculating emissions.

(8) Local distribution companies and energy service companies must separately

and individually calculate end-user emissions of CH_4, N_2O, CO_2 from biomass-derived fuels, and CO_2e by replacing CO_2 in Equation 2.17-2 as provided in paragraph (6) of this subdivision, with CH_4, N_2O, CO_2 from biomass-derived fuels, and CO_2e. CO_2 emissions from biomass-derived fuel are based on the fuel the LDC or an energy service company has contractually purchased on behalf of and delivered to end users. LDCs or energy service companies can elect to report biomethane directly purchased by an end user and delivered by the LDC or energy service company if the LDC or energy service company can provide the information required by section 1.4(f)(3) of this Part. Emissions from contractually purchased biomethane are calculated using the methods for natural gas required by this section, including the use of the emission factor for natural gas found in table NN-1 40 CFR § 98.408 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title). Biomass-derived fuels directly purchased by end users and delivered by the LDC or energy service company must be reported as natural gas by the LDC or energy service company, unless the LDC or energy service company has elected to report the delivery as biomethane and can provide the necessary documentation during verification to determine exemption status as stated above.

(9) The importer of compressed natural gas or liquefied natural gas into New York must estimate CO_2 using calculation methodology 1 as specified in 40 CFR § 98.403(a)(1) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), except that the product of HHV and Fuel is replaced by the annual MMBtu of the imported compressed natural gas and liquefied natural gas.

(10) The importer of compressed natural gas or liquefied natural gas into New

York must estimate and report CH_4 and N_2O emissions using Equation C-8 and table C-2 as described in 40 CFR § 98.33(c)(1) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title).

(11) Operators of facilities that make liquefied natural gas products or compressed natural gas products as described in paragraph (a)(4) of this section must estimate CO_2 using calculation methodology 1 as specified in 40 CFR § 98.403(a)(1) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), except that the product of HHV and Fuel is replaced by the annual MMBtu of the liquefied natural gas sold or delivered in New York.

(12) Operators of facilities that make liquefied natural gas products or compressed natural gas products as described in paragraph (a)(4) of this section must estimate and report CH_4 and N_2O emissions based on the MMBtu of liquefied natural gas sold or delivered using Equation C-8 and table C-2 as described in 40 CFR § 98.33(c)(1) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title).

(13) All fuel suppliers in this section must also estimate CO_2e emissions using equation 2.17-3 as provided in this paragraph:

Equation 2.17-3: $CO_2e = \sum_{i=1}^{n} GHG_i \times GWP20_i$

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.

GHGi = Mass emissions of CO_2, CH_4, N_2O from fuels or products.

GWP20i = Global warming potential for each GHG as specified in the CO_2 equivalence definition of this Part.

n = Number of greenhouse gases emitted.

(14) Fuel suppliers in this section must also estimate CO_2e emissions from fossil fuels for the upstream out-of-state emissions associated with the use of these fuels in New York pursuant to the emission factors specified in section 2.18 of this Part.

(15) All fuel suppliers in this section may make a demonstration to the department that the fuels or products supplied to an end user or facility were used to make a durable product which is ultimately not combusted or used as a fuel.

(i) Without a demonstration, fuel and products are assumed to be combusted or otherwise emitted as a fugitive or vented emission.

(ii) The demonstration must meet the requirements of the department.

(iii) Fuel suppliers making successful demonstrations for quantities of fuel or product determined to be turned into durable products are required to report the upstream out of state emissions associated with the fossil fuels in these products pursuant to section 2.18 of this Part.

(c) Monitoring and QA/QC Requirements. For each emissions calculation method chosen under this section, the supplier must meet all monitoring and QA/QC requirements specified in 40 CFR § 98.404 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), except as modified in this subdivision, and sections 1.4 and 2.7 of this Part.

(1) All natural gas suppliers must measure required values at least monthly.

(2) All natural gas suppliers must determine reporter specific HHV at least monthly, or if the local distribution company or energy service company does not make its own measurements according to standard business practices it must use the delivering pipeline measurement.

(3) All natural gas liquid fractionators must sample for composition at least monthly.

(d) Data Reporting Requirements.

(1) For the emissions calculation method selected under subdivision (b) of this section, natural gas liquid fractionators must report, in addition to the data required by 40 CFR § 98.406(a) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), the annual volume of liquefied petroleum gas, corrected to 60°F, that was produced on-site and sold or delivered to others, except for products for which a final destination outside New York can be demonstrated. Natural gas liquid fractionators must report the annual quantity of liquefied petroleum gas produced and sold or delivered to others as the total volume in barrels as well as the volume of the individual components for all components listed in 40 CFR part 98 table MM-1 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title). Fractionators must also include the annual CO_2, CH_4, N_2O, and CO_2e mass emissions (metric tons) from the volume of liquefied petroleum gas reported in 40 CFR § 98.406(a)(5) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) as modified by this Part, calculated in accordance with subdivision (b) of this section.

(2) For the emissions calculation method selected under subdivision (b) of this

section, local distribution companies and energy service companies must report all the data required by 40 CFR § 98.406(b) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) subject to the following modifications:

(i) Publicly owned natural gas utilities that report in-state receipts at the city gate under 40 CFR § 98.406(b)(1) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) must also identify each delivering person by name and report the annual energy of natural gas received in MMBtu.

(ii) Local distribution companies that report under 40 CFR § 98.406(b)(1) through (b)(7) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) must also report the annual energy of natural gas in MMBtu associated with the volumes.

(iii) In addition to the requirements in 40 CFR § 98.406(b)(8) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), local distribution companies and energy service companies must also include CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e annual mass emissions in metric tons calculated in accordance with 40 CFR § 98.403(a) and (b)(1) through (4) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) as modified by subdivision (b) of this section.

(iv) In addition to the reporting requirements in 40 CFR § 98.406(b)(6) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), local distribution companies, energy service companies, and intrastate pipelines that deliver natural gas to downstream gas pipelines and other local distribution companies or energy service companies, must report the annual energy in MMBtu, and the information required in 40 CFR § 98.406(b)(12) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title).

(v) In lieu of reporting the information specified in 40 CFR § 98.406(b)(7) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), local distribution companies, energy service companies, and intrastate pipelines must report the annual energy in MMBtu, customer information required in 40 CFR § 98.406(b)(12) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), and the department ID number if available for all end-users registering supply equal to or greater than 105,500 MMBtu during the calendar year. In addition to reporting the information specified in 40 CFR § 98.406(b)(13) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), local distribution companies, energy service companies, and intrastate pipelines that deliver to end users must report the annual energy in MMBtu delivered to the following end-use categories: residential consumers; commercial consumers; industrial consumers; electricity generating facilities; vehicle fuel; and other end-users not identified as residential, commercial, industrial, or electricity generating facilities as described by Form EIA-176 (2024) (see Table 1, section 200.9 of this Title). Local distribution companies and energy service companies must also report the total energy in MMBtu delivered to all New York end-users.

(vi) Local distribution companies that report under 40 CFR § 98.406(b)(9) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) must report annual CO_2, CO_2 from biomass-derived fuel, CH_4, N_2O, and CO_2e emissions (metric tons) that would result from the complete combustion or oxidation of the natural gas supplied to all entities calculated in accordance with subdivision (b) of this section.

(3) In addition to the information required in 40 CFR § 98.3(c) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), the operator of an interstate

pipeline that is not a local distribution company must report the customer name, address, and the department ID along with the annual energy of natural gas in MMBtu for natural gas delivered to each customer, including themselves.

(4) In addition to the information required in 40 CFR § 98.3(c) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), the operator of an intrastate pipeline that delivers natural gas directly to end users must follow the reporting requirements described under subpart NN of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) and this section for local distribution companies. In lieu of the city gate information specified by paragraph (b)(2) of this section, the intrastate pipeline operator must report the summed energy (MMBtu) of natural gas delivered to each person receiving gas from the intrastate pipeline for purposes of estimating the CO_2i parameter as specified in paragraph (b)(6) of this section. Additionally, intrastate pipeline operators are required to estimate a value for CO_2j as specified in paragraph (b)(3) of this section for natural gas delivered to local distribution companies, interstate pipelines, energy service companies, and other intrastate pipelines. The CO_2l parameter (for storage and direct deliveries from producers) as specified in paragraph (b)(4) of this section must have a value of 0 (zero) for calculating emissions using equation 2.17-2 as provided in paragraph (b)(6) of this section.

(5) All importers of compressed or liquefied natural gas into New York and liquefied natural gas production facilities as described in paragraph (a)(4) of this section must report the annual quantities imported, and delivered or sold, respectively, in MMBtu, and report CO_2, CH_4, N_2O, and CO_2e annual mass emissions in metric tons separately for compressed natural gas and liquefied natural gas using the calculation methods in

subdivision (b) of this section.

(6) In addition to the information required in 40 CFR § 98.3(c) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), all local distribution companies and energy services companies that report biomass emissions from biomethane fuel that was contractually purchased by the LDC or energy service company on behalf of and delivered to end users, and all liquefied natural gas production facilities reporting biomass emission from biomethane, must report, for each contracted delivery, the information specified in section 1.4(f)(3) of this Part.

(7) All operators of facilities that make liquefied natural gas products as described in paragraph (a)(4) of this section must report end-user information for deliveries of liquefied natural gas to industrial facilities and natural gas utility customers, including customer name, address, and the annual quantity of liquefied natural gas delivered to each customer in MMBtu.

(8) All natural gas liquid fractionators identified in this section must report the total quantity in barrels of liquefied petroleum gas that is excluded from emissions reporting due to demonstration of a final destination outside New York.

(9) Local distribution companies and energy service companies must report annually a summary of monthly gas sales, transfers, or deliveries to end users in New York. The content of this report shall include for each county in the service area:

(i) the number of residential, commercial, or industrial meters receiving natural gas;

(ii) the total quantity of natural gas received through meters; and

(iii) the number of meters receiving quantities of natural gas that fall into discretized five-therm increments.

(e) Procedures for estimating missing data. Suppliers must follow the missing data procedures specified in 40 CFR § 98.405 (Amended November 18. 2024) (see Table 1, section 200.9 of this Title). The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 1.7 of this Part.

(f) A natural gas, natural gas liquids, compressed natural gas, and liquid natural gas supplier shall provide:

(1) the data used to calculate emissions from the utilization of the fuel delivered, transferred, or sold to large emission sources, pursuant to section 1.2(f) of this Part, and other Reporting Entities of this Part that are the customers or end users of this fuel; and

(2) the name(s) of the facility, the customer account number(s), and annual MMbtus delivered, transferred, or sold to large emission sources, pursuant to section 1.2(f) of this Part, and other Reporting Entities of this Part that are customers or end users of the fuel supplier to the department.

253-2.18 Upstream Out-of-State Emissions from Fossil Fuels or Products

Owners or operators of facilities, suppliers of fossil fuels or products into New York and electric power entities that are required to report under section 1.2 of this Part must comply with all applicable requirements below.

(a) Any fuel supplier, electric power entity, or facility shall report upstream out-of-state emissions for each MMBtu of fuel or products sold or brought into New York for sale to an end user, or consumed or used at a facility, or used to produce electricity imported into New York.

(1) These emissions shall be reported by multiplying the emission factor provided in Table 2-6 of this section by the MMBtus reported as fossil fuel or products, sold to an end user, provided for sale to end users, or reported as used by a facility. Emission factors from Table 2-6 shall be utilized for fossil fuels or products as indicated in Table 2-6.1 of this section, unless otherwise specified in this Part.

Table 2-6: Upstream Out-of-State Emission Factors	
Fuel or Product Category	Emission factor (kg CO_2e per mmbtu)
Natural Gas	40.877
Coal	41.939
Diesel/Distillate Fuel	23.540
Gasoline/Blendstocks	28.866
Kerosene/Jet Fuel	18.193
LPG	26.474
Petroleum Coke	20.114
Residual Fuel	19.411
Asphalt and Road Oil	16.438
Lubricants	27.026
Waxes	26.386
Miscellaneous Petroleum Products	18.977
Special Naphthas	22.591

Table 2-6.1: Fuel or Product and Corresponding Fuel Category for Upstream Out-of-State Emission Factors	
Fossil Fuel or Product:	Fuel or Product Category (from Table 2-6):
Asphalt and Road Oil	Asphalt and Road Oil
Coal (all types)	Coal
Distillate (all types)	Diesel/Distillate Fuel

Blendstocks (all types)	Gasoline/Blendstocks
Kerosene	Kerosene/Jet Fuel
Kerosene-type Jet Fuel	Kerosene/Jet Fuel
Butylene	LPG
Ethylene	LPG
Isobutylene	LPG
Liquid Petroleum Gas (LPG)	LPG
Propane	LPG
Propylene	LPG
Lubricants	Lubricants
Miscellaneous Petroleum Products	Miscellaneous Petroleum Products
Butane	Natural Gas
Ethane	Natural Gas
Isobutane	Natural Gas
Natural Gas	Natural Gas
Pentanes Plus	Natural Gas
Petroleum Coke	Petroleum Coke
Residual Fuel (all types)	Residual Fuel
Special Naphtha	Special Naphtha
Waxes	Waxes

(2) A fuel supplier, electric power entity, or facility may use basin specific emission factors for natural gas provided in Table 2-7 of this section if it can demonstrate to the department through invoices, bills of lading, or other fuel analytical data that the origin of that natural gas can be shown to come from a specific production basin.

Table 2-7: Basin Specific Emission Factors	
Basin	Emission factor (kg CO_2e per mmbtu)
Gulf Conventional	44.740
East Texas Conventional	28.055
Anadarko Conventional	46.798
Arkoma Conventional	66.184
Appalachia Conventional	258.553
Gulf Shale	62.196
East Texas Shale	30.965
Anadarko Shale	28.843

Arkoma Shale	34.369
Appalachia Shale	29.798
Gulf Tight	27.325
East Texas Tight	35.158
Anadarko Tight	38.512

(b) Any fuel supplier shall report the following data or source information for fuel sold or brought into New York for sale to end user for each calendar year.

(1) The quantity of fuel by type as listed in Table 2-6 of this section in units of MMBtu for all fuels including solid, liquid, and gaseous fuels. Additionally, fuel suppliers must report the quantity of fuel by type imported into New York in units of metric tons for solid fuels, barrels for liquid fuels, or Mscf (a thousand standard cubic feet) for gaseous fuels.

(2) The corporation's name and physical address of the fuel production facility or upstream entity that sold the fuel product to the fuel supplier. The physical address must include the street address, city, state, and zip code. If the fuel production facility or upstream entity does not have a physical street address, then the fuel supplier must provide the latitude and longitude representing the geographic centroid or center point of fuel production facility operations in decimal degree format. This must be provided in a comma-delimited "latitude, longitude" coordinate pair reported in decimal degrees to at least four digits to the right of the decimal point.

(3) The transportation distance of the imported fuel from the fuel production facility specified in subdivision (c) of this section to the New York border in miles and the mode of transportation used to transmit the fuel to the New York border. Fuel suppliers must report the distance traveled by the fuel for each mode used to transmit the fuel to the New York border in miles.

(4) Liquid fuel suppliers and petroleum fuel suppliers must report the following data for petroleum fuels imported into New York.

(i) The API gravity.

(ii) Carbon ratio in units of percent by weight.

(iii) Sulfur ratio in units of parts per million by weight.

(iv) Low heating value and high heating value in units of MMBtu per barrel.

(v) The portion of biofuels blended into the petroleum fuel in percent.

(vi) The modes used to transport the petroleum fuel from the fuel production facility to the New York border including, but not limited to, transport by rail, ocean tanker, barge, truck, or pipeline and the following information for the specific modes of transport:

(‘a’) For rail transport, the energy intensity in MMBtu per ton-mile and average speed in meters per second of the rail.

(‘b’) For ocean tanker or barge transport, the average speed in meters per second, power in horsepower, and load factor of the ship.

(‘c’) For trucks, the fuel economy in miles per gallon.

(‘d’) For pipelines, the fuel type transported in the pipeline and the energy intensity of the pipeline in MMBtu per ton-mile.

(5) Coal suppliers must report the following data for coal imported into New York.

(i) The high heating value as required under section 2.15(b)(1) of this

Part.

(ii) The type of coal imported including anthracite, bituminous, sub-bituminous, or lignite.

(iii) The methods used to transport the coal to the New York border including, but not limited to, transport by conveyor belt, truck, barge, ocean vessel, or train.

(iv) The percentage of total imported coal that is cleaned or processed to remove impurities.

(6) Natural gas suppliers must report the following fuel specifications for natural gas imported into New York.

(i) The low heating value and high heating value of the imported natural gas in units of MMBtu per Mscf (one thousand standard cubic feet).

(ii) The mass fraction of methane of the imported natural gas.

(c) Any fuel production facility or other entity that sells a fuel product to a fuel supplier must report the following data or information for each calendar year.

(1) Fuel producers shall report the quantity of fuel by type used on site or combusted by stationary fuel combustion sources described in 40 CFR § 98.30 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) in units of MMBtu.

(2) Petroleum refiners must comply with the data reporting requirements described in 40 CFR § 98.396(a) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title) and report the following data.

(i) The type of crude oil processed at the refinery including conventional crude oil, shale oil, or oil sands.

(ii) The share of total crude oil processed at the facility that is sourced from the United States, Canada, Mexico, the Middle East, Latin America, Africa, or other locations in percent. For crude oil sourced from the United States, report the source basin of crude oil processed at the facility.

(iii) The quantity of petroleum products by type sold to New York fuel suppliers specified in section 1.2 of this Part in units of barrels.

(iv) The mode of transportation, as specified in subparagraph (b)(4)(vi) of this section, used to transmit the crude oil from the original source or extraction point to the refinery and the distances traveled by the crude oil on each mode of transportation in miles. If the refiner does not know the modes used to transport crude oil to the refinery, then the refiner shall report the distance between the geographic origin of the fuel and the refinery.

(v) The API gravity of crude oil processed at the facility.

(vi) The sulfur content of crude oil processed at the facility in units of percent by weight.

(vii) The refinery heavy product yield or the ratio of the yield of residual fuel oil, asphalt, coke, slurry oil, and reduced crude in MMBtu to the yield of total products in MMBtu made at the refinery.

(viii) The Refinery Complexity Index (RCI) of the facility using Equation 2.18-1 as provided in this subparagraph:

Equation 2.18-1: $RCI = 1 + \Sigma_i [(Q_i/Q_o) * CF_i]$

Where:

Q_i is the capacity of refinery operation *i* in barrels per day;

Q_o is the distillation capacity of the refinery in barrels per day;

CF_i is the Nelson complexity factor of the refinery operation ***i*** as defined in Table 2-8 of this section.

Table 2-8: Complexity Factors for Refining Operations	
Refinery Operation	Complexity Factor (CF_i)
Atmospheric Distillation	1
Vacuum Distillation	2
Thermal cracking	2.75
Delayed coking	6
Catalytic cracking	6
Catalytic reforming	5
Catalytic hydrocracking	6
Catalytic hydrorefining	3
Catalytic hydrotreating	2
Alkylation	10
Polymerization/dimerization	10
Aromatics	15
Isomerization	15
Lubes Production	10
Oxygenate Production	10
Hydrogen Production	1
Asphalt Production	1.5

(ix) For gasoline products, report the following data.

('a') The percentage of ethanol blended into the fuel.

('b') The O_2 content of the gasoline product in units of percent by weight.

('c') The percentage share of corn, willow, poplar, switchgrass, miscanthus, corn stover, forest residue, sorghum, integrated corn/stover, sugarcane, or solid waste used as ethanol feedstocks.

(x) The source of H_2 production for use in the refinery including natural gas, proton exchange membrane electrolysis, or nuclear high temperature electrolysis.

(3) Coal mines must report the following data for each calendar year.

(i) The type of coal mined as specified in subparagraph (b)(5)(ii) of this section.

(ii) The transmission distance of the coal from the mine to the fuel supplier in units of miles and the mode of transport including conveyor belt, truck, barge, ocean vessel, or train.

(iii) The extraction method of the coal including underground mining or surface mining.

(4) Natural gas processing facilities must report the following data for each calendar year.

(i) The quantity of natural gas throughput at the facility in units of Mscf.

(ii) The source basin of the raw natural gas as specified in Table 2-7 of this section and the type of natural gas processed at the facility including conventional onshore gas, conventional offshore gas, associated gas, tight gas, shale gas, and coal bed methane.

(iii) The quantity of methane emitted from acid gas removal in units of kg methane per kg natural gas.

(iv) The quantity of methane emitted from dehydrator venting, centrifugal compressor venting, and reciprocating compressor venting in units of metric tons.

(d) Monitoring, Data, and Records. Any fuel supplier or fuel production facility who is required to report under section 1.2 of this Part must maintain records supporting the receipt and sale of petroleum fuels, natural gas, or coal to an individual or retail location in New York. The suppliers must retain the following records for five years substantiating each of the supplies that they report.

(1) Invoices, an electronic record of transfers, or any other records used to determine or that can verify the quantities reported under subdivision (b) and subdivision (c) of this section.

(2) An electronic record of entities from which supplies were received or that the reporting entity supplied during each reporting year.

253-2.19 Waste Haulers and Transporters

A transporter of solid waste who is required to report under section 1.2 of this Part and that exceeds an applicability threshold under subdivision (a) of this section must report annual emissions and other data as specified in this section.

(a) Applicability Threshold. Transporters of solid waste are required to report under this section if they transport an amount of solid waste that exceeds any of the following threshold levels. Short tons shall be converted to metric tons where indicated.

(1) The estimated emissions from solid wastes transported to landfills or

combustion facilities outside of New York exceed 10,000 MT CO_2e emissions per year, using Equation 2.19-1 as provided in this paragraph. Unspecified waste shall be assessed in the same manner as waste deposited in a municipal solid waste (MSW) landfill and included in emission calculations for landfills. This threshold would be equivalent to the emissions from solid waste transported out of state to landfill facilities and/or that is unspecified waste exceeding 1,750 metric tons in any year, or to combustion facilities exceeding 12,220 metric tons in any year.

Equation 2.19-1: $CWE = (W_X*LWF) + (CW_X*CWF)$

Where:

CWE = Combined waste emissions

W_X = Annual tonnage of waste transported for the purposes of disposal in landfills or unspecified wastes (metric tons)

LWF = Landfill waste factor or 5.71t CO_2e per metric ton

CW_X = Annual tonnage of waste transported for the purposes of combustion (metric tons)

CWF = Emission factors for CO_2 for municipal solid waste and for CH_4 and N_2O for other solid fuels included in subpart C of 40 CFR part 98 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title).

(2) The estimated emissions from solid wastes transported to landfills outside of New York exceed 10,000 MT CO_2e emissions per year, using Equation 2.19-2 as provided in

subdivision (b) of this section.

(b) CH_4 from landfilled or unspecified waste. Applicable Reporting Entities under subdivision (a) of this section are required to report the mass of CH_4 that would result from the disposal of solid waste into industrial or MSW landfills located outside of New York. Unspecified waste shall be assessed in the same manner as waste deposited in a MSW landfill and included in emission calculations for landfills.

Equation 2.19-2: $CO_2e_{LW} = [G_{CH4} * (1\text{-}OX)] * GWP20_{CH4}$

Where:

CO_2e_{LW} = Annual CH_4 generation from solid wastes transported to landfills outside of New York or for which the ultimate destination is unspecified, starting with the first reporting year.

G_{CH4} = Methane generation rate following 40 CFR § 98.343(a) (Amended April 25, 2024) (see Table 1, section 200.9 of this Title) for MSW or unspecified waste or 40 CFR § 98.463(a) (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), incorporated by reference herein, using appropriate default values and where the start year of calculation (S) is the first reporting year.

OX = Oxidation fraction based on a default value of 0.10

(c) Combusted solid waste. Entities are required to report the mass of CO_2, CH_4, and N_2O emissions that would result from the combustion of solid waste transported to stationary combustion facilities outside of New York, using Equation 2.19-3 as provided in this subdivision.

Equation 2.19-3: $CO_2e_{CW} = (CW * CWF_{CO2}) + (CW * CWF_{CH4} * GWP20_{CH4}) + (CW * CWF_{N2O} * GWP20_{N2O})$

Where:

CO_2e_{CW} = Annual CH_4 emissions from solid wastes transported to landfills outside of New York, starting with the first reporting year

CW = Annual tonnage of waste transported for the purposes of combustion (metric tons / year)

CWF = Emission factors for CO_2 for municipal solid waste and for CH_4 and N_2O for other solid fuels included in subpart C of 40 CFR part 98 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title)

(d) Additional Methane Data Collection. Transporters subject to reporting requirements under this section may apply to use a revised DOC following the solid waste composition verification procedures under section 2.20(b) of this Part.

(e) Additional data reporting requirements. Each entity must submit an annual report that summarizes transportation of solid waste from New York as follows.

(1) Total mass in metric tons of solid waste transported from New York to locations outside of New York.

(2) The aggregated annual quantity of solid waste in metric tons that can be attributed to the following.

(i) Name and location of the facility from which the waste was received.

(ii) The type of facility from which the waste was received including municipal or commercial.

(iii) Name and location of the final destination to which the waste was transported.

(iv) The type of facility to which the waste was transported including landfills, combustion facilities, composting and other organics processing facilities or organics recycling facilities, recyclables handling and recovery facilities, or unspecified facilities.

(f) Records. In addition to the data required under subdivision (d) of this section, entities must retain the following records for five years.

(1) Invoices, an electronic record of transfers, or any other records used to determine or that can verify the quantities reported under subdivision (e) of this section.

(2) An electronic record of entities from which wastes were received or that the reporting entity transported wastes to during each reporting year.

253-2.20 Additional Methane Data Collection

(a) Emissions Monitoring and Measurement Plan. Operators of solid and liquid waste management facilities that are required to report under sections 2.13 and 2.2 of this Part and exceed the applicability threshold in paragraph (1) of this subdivision shall develop and implement an operation or facility-specific Emissions Monitoring and Measurement Plan

(EMMP) in addition to meeting reporting requirements in sections 2.13 and 2.2 of this Part.

(1) Applicability: Operators are required to develop and implement an EMMP for facilities that met the following criteria.

(i) the operator of the anaerobic digester or liquid storage were required to report under section 2.2(a)(1) of this Part and were not eligible for abbreviated reporting under section 2.2(a)(2) of this Part; or

(ii) the operator of the solid waste landfill reported annual emissions exceeding 300,000 MT CO_2e emissions calculated according to section 2.13 of this Part.

(2) Department Approval: The operator of an applicable facility or operation must submit an EMMP proposal to the department no later than March 1, 2026, and every three years thereafter in a format approved by the department. Approval of the proposal by the department is required. Proposals must include the following.

(i) a timeline for completing and reporting EMMP results to the department by March 1, 2029, and every three years thereafter;

(ii) the name and contact information of an authorized representative of the facility operator along with their signed certification confirming that the statements and information submitted are true, accurate, and complete;

(iii) the name and contact information for any third parties involved in proposal development or implementation;

(iv) a scaled operation or facility site plan that delineates the area over which emissions will be monitored and identifies the locations of landfills, gas capture systems, gas flares, anaerobic digesters or reactors, liquid, or slurry waste storages and other waste-derived emission sources;

(v) the duration of monitoring;

(vi) methods for accepting, comparing, and reconciling activity and operational data with emissions measurements; and

(vii) measurement and monitoring procedures that may be based on recommended guidance from the department and which may include but are not limited to the following:

(‘a’) reporting leak detection and repair for operations that include biogas flaring or biogas capture systems such as landfills and anaerobic digesters or reactors;

(‘b’) emissions detection exercises that are able to capture higher volume emission events that happen at a low frequency or intermittently;

(‘c’) detection exercises that are undertaken at an appropriate frequency to capture potential temporal variation in emissions;

(‘d’) detection exercises that capture emissions from an area that includes a statistically significant population of relevant emission sources;

(‘e’) measurement exercises that are undertaken at an appropriate frequency to capture potential temporal variation in emissions;

(‘f’) measurement exercises that capture emissions from an area that includes a statistically significant population of relevant emission sources;

(‘g’) measurement of emissions from all sources determined to be above a threshold which may be activity-based;

('h') a process for disaggregating equipment-level emissions or other individual emission sources that are within the monitoring or measurement footprint for site-level methods;

('i') quantification of uncertainty associated with the proposed emissions measurements and methods for assessing the uncertainty associated with individual emission sources and site-level emissions; or

('j') plans for record keeping and documentation that may include leak detection and repair survey results, results of regular equipment performance testing and maintenance, calibration curves, and standard operating procedures for each analytical method or instrument.

(3) Results Submission: The operator of a facility must submit to the department the completed EMMP results for the previous calendar year in a format approved by the department no later than March 1, 2029, and every three years thereafter. The operator of a facility must submit a completed report that follows an approved EMMP and will include the information required to obtain accurate and unbiased emissions data from individual sources, pursuant to ECL 75-0105(4).

(4) Third-party services and group submissions: EMMP proposals may be developed by an entity other than the operator of the facility with expertise in emissions quantification methodologies and may incorporate monitoring at multiple facilities, operations, or on behalf of multiple operators.

(5) Cessation of EMMP. After an operator of a facility has completed and submitted one round of EMMP data collection and documentation, the department may then

determine that the operator is exempt from subsequent rounds of EMMP. Exemption from completing a round of EMMP does not exempt a facility operator from annual reporting of the facility's activity data or annual emissions to the department under sections 2.13 or 2.2 of this Part. If activity data or emissions reported to the department indicate the likely exceedance of 10,000 MT CO_2e emissions in any year after cessation requirements have been met, the department may require the operator to resume EMMP data collection, documentation, and submission, and the operator must meet all applicable requirements under this section.

(b) Solid Waste Composition Verification. Operators of landfill facilities and waste transporters required to report under sections 2.13 or 2.19 of this Part may apply to the department to revise the method used to calculate reported emissions if they are able to provide sufficient documentation that the degradable organic carbon fraction of the waste accepted by the facility is different from the degradable organic carbon fraction used in sections 2.13 or 2.19 of this Part. Applications must be submitted to the department before March 1st of each year and in a format that is acceptable to the department. Approval by the department is required before a revised degradable organic carbon value can be used in subsequent reporting.

(1) Methods for documenting the degradable organic carbon fraction of the waste accepted at a facility should be developed in coordination with the department and may include waste composition audits, quantifying variability in the degradable organic carbon fraction of the facility's total accepted waste during the reporting year, quantifying other sources of uncertainty in measurements of the degradable organic carbon fraction, and documentation of the quantity of waste audited relative to the quantity of waste accepted for placement at the

facility.

(2) Records that document or substantiate an application to revise the composition of the waste accepted by a facility must be retained for five years after the application is submitted to the department and must be made available to the department upon request. Such documentation may include but is not limited to invoices from organics diversion programs, invoices, and other documentation of waste audits by third parties, or bills of lading.

253-2.21 Fluorinated Greenhouse Gases

Operators of facilities required to report under sections 1.1 and 1.2 of this Part must comply with all applicable requirements below. This includes producers of industrial GHGs and facilities that use equipment that contains refrigerant.

(a) Producers of fluorinated GHGs. Operators of facilities required to report under section 1.2 of this Part must comply with the requirements of subpart L of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title).

(b) Fugitive Refrigerant Sources. Operators of facilities required to report under sections 1.1 and 1.2 of this Part must provide an annual report on fugitive refrigerant sources. Fugitive refrigerant sources are devices that contain 50 pounds or greater of fluorinated GHGs as refrigerants used for heat transfer purposes. Fugitive refrigerant sources include, but are not limited to, commercial air-conditioning or heat pump equipment or systems, industrial process equipment or systems, or other commercial refrigeration equipment or systems. The annual report must include the following.

(1) Annual emissions of fluorinated GHGs in CO_2e based on leak rate as

estimated using the rolling average method under 40 CFR § 82.152 (November 18, 2016) (see Table 1, section 200.9 of this Title). Annual emissions shall be product of the leak rate, refrigerant charge size, and GWP20 of the refrigerant, summed for all applicable fugitive refrigerant sources at the facility.

(2) Annual reporting information as provided in section 494-2.6(b) of this Title.

(c) Monitoring, Data, and Records.

(1) Production facilities subject to reporting requirements in this section must maintain records and make available upon request by the department a copy of the following information, pursuant to section 1.7 of this Part, where applicable.

(i) Invoices of all fluorinated GHGs distributed or received in New York through sale or transfer, indicating business names, business addresses, the date of sale or transfer, the quantity of each type of fluorinated GHG sold or transferred, and the name and email address of an authorized representative for the supplier and recipient.

(ii) A list of all known suppliers, purchasers, or other recipients for the previous five years, including business names, business address, and the name and email address of an authorized representative for each business.

(iii) Facility information, including the mailing address and the name, title, and email address for an authorized representative for each manufacturing, distribution, wholesale, destruction, or reclaim facility under the operational control of the person or business.

(iv) Any other records used to determine or that can verify the quantities reported under this section.

(2) Facilities subject to report under this section must maintain records as provided in section 494-2.7 of this Title.

(3) Fugitive refrigerant emission sources. Operators of facilities subject to reporting under subdivision (b) of this section must maintain records and make available to the department the following information, pursuant to section 1.7 of this Part.

(i) Documentation of all leak inspections, dates and locations of identified leaks, dates on which any automatic leak detection systems triggered an alert, and annual audit and calibrations for leak inspection devices and automatic leak detection systems.

(ii) Records of service and leak repairs including the name of the person performing the service, dates of refrigerant additions or equipment repairs.

(iii) Invoices of all purchases of regulated substances.

(iv) Records of all shipments of regulated substances for reclamation or destruction. The records must include all of the following information:

(‘a’) name and address of the person the regulated substance was shipped to;

(‘b’) date of shipment;

(‘c’) regulated substance shipped; and

(‘d’) purpose of shipment (e.g., reclamation or destruction).

(v) Records of all refrigeration or air conditioning component data, measurements, calculations, and assumptions used to determine the full refrigerant charge capacity and leak rate.

253-2.22 Industrial Product Data Reporting Requirements

(a) A large emission source from an industrial sector listed in Table 2-9 of this section must also report total annual production data associated with all NAICS codes applicable to activity at the facility, including but not limited to specific product descriptions and units of production for each specific product based on each such NAICS code.

(1) Large emission sources reporting industrial product data must report product data using consistent units for each reporting year. If applicable to the product, the product data should be reported in mass units. The department may accept a change of the reporting unit if a large emission source submits a written request justifying the change.

Table 2-9: Industrial Product Data Reporting NAICS Codes	
NAICS Sector Description	NAICS Code
Food Manufacturing	311XXX
Beverage and Tobacco Product Manufacturing	312XXX
Textile Mills	313XXX
Textile Product Mills	314XXX
Apparel Manufacturing	315XXX
Leather and Allied Product Manufacturing	316XXX
Wood Product Manufacturing	321XXX
Paper Manufacturing	322XXX
Printing and Related Support Activities	323XXX
Petroleum and Coal Products Manufacturing	324XXX
Chemical Manufacturing	325XXX
Plastics and Rubber Products Manufacturing	326XXX
Nonmetallic Mineral Product Manufacturing	327XXX
Primary Metal Manufacturing	331XXX
Fabricated Metal Product Manufacturing	332XXX
Machinery Manufacturing	333XXX
Computer and Electronic Product Manufacturing	334XXX
Electrical Equipment, Appliance, and Component Manufacturing	335XXX
Transportation Equipment Manufacturing	336XXX
Furniture and Related Product Manufacturing	337XXX
Miscellaneous Manufacturing	339XXX

Subpart 253-3. Additional Requirements for Reported Data

253-3.1 Substitution for Missing Data Used to Calculate Emissions from Stationary Combustion and CEMS Sources.

In lieu of the requirements for estimating missing data in subpart C of 40 CFR part 98 (Amended May 14, 2024) and subpart D of 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title), the operator of a facility who is reporting emissions under sections 2.5 or 2.7 of this Part must follow the applicable procedures of this section for estimating missing or invalid data. The operator must include the substituted data in the GHG emissions data report and maintain all records, calculations, and data used to estimate substituted data according to the requirements of section 1.7 of this Part and 40 CFR part 98 (Amended November 18, 2024) (see Table 1, section 200.9 of this Title). Alternatively, under the limited circumstances specified in this section for equipment breakdown, the operator may request approval of an interim data collection procedure as specified in subdivisions (h) and (i) of this section. For units combusting biomass-derived fuels or for sources using limited alternative emissions provisions in section 1.4(e) of this Part, the operator who is reporting emissions must follow either the requirements below or the requirements of 40 CFR § 98.35 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title). In the event that this section becomes applicable to a source, compliance with the requirements of this section does not relieve the operator from complying with other sections of this Part.

(a) Missing Data Substitution Procedures for Units Reporting Under 40 CFR Part 75. The operator of a unit that is reporting CO_2 using 40 CFR part 75 (July 1, 2023) (see Table 1, section 200.9 of this Title) must follow the applicable missing data substitution procedures in subpart D of 40 CFR part 75 (July 1, 2023) (see Table 1, section 200.9 of this Title) and appendix C to 40 CFR part 75 (July 1, 2023) (see Table 1, section 200.9 of this Title) for CO_2 concentration, stack gas flow rate, fuel flow rate, high heat value, and fuel carbon content, except as otherwise provided in this section. Subdivisions (b) through (g) of this section do not apply to these units for CO_2 emissions. The operator may use applicable missing data procedures under 40 CFR part 75 (July 1, 2023) (see Table 1, section 200.9 of this Title) or the procedures in subdivisions (b) through (g) of this section for CH_4 and N_2O emissions that are not designated as limited alternative emissions as provided in section 1.4(e) of this Part if data required for calculating CH_4 and N_2O emissions are missing or invalid.

(b) Missing Data Substitution Procedures for Other Units Equipped with CEMS. The operator of a stationary combustion unit who monitors and reports emissions and heat input data for that unit under section 2.7 of this Part using Tier 4 of 40 CFR § 98.33(a)(4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) must follow the applicable missing data substitution procedures in 40 CFR § 75.31-.37 (July 1, 2023) (see Table 1, section 200.9 of this Title). For the purpose of missing data substitution, for CEMS certified under 40 CFR part 60 (July 1, 2024) (see Table 1, section 200.9 of this Title), quality-assured data is defined according to the quality assurance/quality control procedures in appendix F to 40 CFR part 60 (July 1, 2024) (see Table 1, section 200.9 of this Title). Subdivisions (c) through (h) of this section do not apply to units using Tier 4 of 40 CFR § 98.33(a)(4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) for CO_2 emissions but do apply for CH_4 and N_2O emissions that are not designated as limited alternative emissions as provided in section 1.4(e) of this Part if data required for calculating CH_4 and N_2O emissions are missing or invalid.

(c) Missing Data Substitution Procedures for Fuel Characteristic Data. When the applicable emissions estimation methods of this Part require periodic collection of fuel characteristic data (including carbon content, high heat value, and molecular weight), the operator must demonstrate every reasonable effort to obtain a fuel characteristic data capture rate of 100 percent for each emission year. When fuel characteristic data of a required fuel sample are missing or invalid, the operator must first attempt to either reanalyze the original sample or perform the fuel analysis on a backup sample, or replacement sample from the same collection period as specified in 40 CFR § 98.34(a)(2) through (3) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), to obtain valid fuel characteristic data. If the sample collection period has elapsed and no valid fuel characteristic data can be obtained from a backup or replacement sample, the operator must substitute for the missing data the values obtained according to the procedures in paragraphs (1) through (3) of this subdivision. The data capture rate for the emission year must be calculated using Equation 3.1-1 as provided in this subdivision for each type of fuel and each fuel characteristic parameter:

Equation 3.1-1: Data capture rate = S / T x 100%

Where:

S = Number of fuel samples for which valid fuel characteristic data were obtained according to the applicable sampling requirements (including sampling schedule)

T = Total number of fuel samples required by the applicable sampling requirements

(1) If the fuel characteristic data capture rate is at least 90 percent for the emission year, the operator must substitute the arithmetic average of the values of that parameter immediately preceding and immediately following the missing data incident that are representative of the fuel type. If the “after” value has not been obtained by the time that the GHG emissions data report is due, the operator must use the “before” value for missing data substitution.

(2) If the fuel characteristic data capture rate is at least 80 percent but not more than 90 percent for the emission year, the operator must substitute for each missed value with the highest valid value recorded for that type of fuel during the emission year, as well as the two previous emission years.

(3) If the operator is unable to obtain fuel characteristic data such that less than 80 percent of a fuel characteristic data element are directly accounted for, the operator must then substitute for each missed data point as follows:

(i) If historical fuel characteristics data are available and kept according to the requirements of section 1.7 of this Part, substitute with the greater of the following:

(‘a’) the highest valid value recorded for that type of fuel for all records kept under the requirements of section 1.7 of this Part; or

(‘b’) the default value in Table 3-1 of this section (for carbon content) or table C-1 of 40 CFR part 98 (for high heat value) (Amended May 14, 2024) (see

Table 1, section 200.9 of this Title). If a substitute value is not available in Table 3-1 of this section or table C-1 of 40 CFR part 98 (Amended May 14, 2024) (see Table 1, section 200.9 of this Title), the operator must substitute the highest value recorded for that type of fuel for all records kept pursuant to the requirements of section 1.7 of this Part.

(ii) For carbon content data, if historical fuel characteristics data are not available and a default value is not listed in Table 3-1 of this section, use 90 percent for other liquid and gaseous fuels and 100 percent for other solid fuels in substituting for missed carbon content data.

Table 3-1: Default Carbon Content	
Parameter	Missing Data Value
Anthracite Coal	90%
Bituminous	85%
Subbituminous/Lignite	75%
Oil	90%
Natural Gas	75%

(d) Missing Data Substitution Procedures for Fuel Consumption Data. An operator subject to the requirements of this Part must demonstrate every reasonable effort to obtain a total facility fuel consumption data capture rate of 100 percent for each year for each type of fuel. The total facility fuel consumption for the emission year can be determined using any combination of meters and/or other fuel measurement devices or methods that individually meet the accuracy requirements of this Part, provided that the total amount of fuel consumed at the facility level is completely accounted for during each time period that the facility is in operation. For each fuel type, when the total facility fuel consumption data that meet the accuracy requirements of this Part are available during each time period that the facility is in operation, but such data are missing or invalid at the unit level, the operator must either estimate missing unit-level fuel consumption data using other available data parameters that are routinely measured at the facility (e.g., electrical load, steam production, operating hours, production output, or fuel consumption data at other measurement points), or use an applicable missing data substitution procedure from paragraphs (1) through (3) of this subdivision. If during any time periods that the facility is in operation, a portion of the total facility fuel consumption is missing or cannot be determined at the accuracy required by this Part, the operator must use the applicable missing data substitution procedure from paragraphs (1) through (3) of this subdivision, so that the total facility fuel consumption quantity for the missing data periods is reconstructed. If a source is eligible for more than one procedure in paragraphs (1) through (3) of this subdivision, the operator has the option to choose one of the applicable procedures in paragraphs (1) through (3) of this subdivision. The requirements in paragraphs (1) through (3) of this subdivision are optional for sources that are not required to meet the accuracy standard specified in section 1.4(g) of this Part and for sources that do not use fuel consumption data for emission calculation.

(1) Continuous Fuel Flow Rate Data Using Load Ranges. The sources that meet the following criteria are eligible for using the procedures in this paragraph: the sources combust gaseous or liquid fuels, produce electrical or thermal output, use a fuel flow meter system to continuously measure fuel flow rate; and are equipped with a data acquisition and handling system or DAHS that continuously records fuel flow rates and measured electrical or thermal output on an hourly basis, which enables segregation of the fuel flow rate data into bins. The operator of such sources that applies the requirements in this paragraph must

substitute missing fuel flow rate data according to this paragraph.

Whenever quality-assured fuel flow rate data are missing and there is no backup system available to record the fuel flow rate, the operator must use the following procedures to account for the flow rate of fuel combusted at the source for each hour during the missing data period. Before using these procedures, operators must establish load ranges for the affected sources using the procedures in subdivision (f) of this section.

When load ranges are used for estimating missing fuel flow rate data, the operator must create and maintain separate fuel-specific databases for the source. The database for each type of fuel combusted must include the hours in which the fuel is combusted alone at the source and the hours in which it is co-fired with any other fuel types. The database must record fuel flow rate and corresponding electrical output or thermal output and assign these values into the established load bins. To be eligible to use the missing data procedures in this paragraph, measured electrical output or thermal output must be available for the hour(s) in which fuel flow rate data are missing. If output data are missing, the operator must follow the requirements of paragraph (3) of this subdivision.

(i) Single Fuel Type. For missing data periods that occur when only one type of fuel is being combusted, the operator must provide substitute data for each hour of the missing data period as follows: Substitute the arithmetic average of the hourly quality-assured fuel flow rate(s) measured and recorded by a fuel flowmeter system at the corresponding operating source load range during the previous 720 operating hours in which the source combusted only that same fuel. If 720 hours of fuel flow rate data are not available at the corresponding load range, the operator may combine available data with data from higher load ranges if available until 720 hours are reached. If 720 hours of quality-assured fuel flow rate data are not available when combined with higher load ranges, the operator must substitute the maximum potential fuel flow rate for each hour of the missing data period.

(ii) Multiple Fuel Types. For missing data periods that occur when two or more different types of fuel are being co-fired, the operator must provide substitute fuel flow rate data for each hour of the missing data period as follows:

(‘a’) Substitute the maximum hourly quality-assured fuel flow rate(s) measured and recorded by a fuel flowmeter system at the corresponding operating source load range during the previous 720 operating hours when the fuel for which the flow rate data are missing was co-fired with any other type of fuel. If 720 hours of fuel flow rate data are not available at the corresponding load range, data from higher load ranges if available may be combined until 720 hours are reached. If 720 hours of quality-assured fuel flow rate data are not available when combined with higher load ranges, the operator must substitute the maximum potential fuel flow rate for each hour of the missing data period.

(‘b’) If, during an hour in which different types of fuel are co-fired, quality-assured fuel flow rate data are missing for two or more of the fuels being combusted, apply the procedures in clause (‘a’) of this subparagraph. separately for each type of fuel.

(‘c’) If the missing data substitution required in clauses (‘a’) and (‘b’) of this subparagraph causes the reported hourly heat input rate based on the combined fuel usage to exceed the maximum rated hourly heat input of the unit, adjust the substitute fuel flow rate value(s) so that the reported heat input rate equals the unit’s maximum rated hourly heat input.

(iii) Lookback Period. In any case where the missing data provisions of this section require substitution of data measured and recorded more than three years (26,280 clock hours) prior to the date and time of the missing data period, the operator must substitute the maximum potential fuel flow rate for each hour of the missing data period. In addition, for sources in operation less than three years (26,280 clock hours), until 720 hours of quality-assured fuel flowmeter data are available for the lookback periods described in subparagraphs (i) and (ii) of this paragraph, the methodology in paragraph (3) of this subdivision must be used to determine the appropriate substitute data values.

(2) Fuel Consumption Data Without Load Ranges. The sources that meet the following criteria are eligible to use the procedures in this paragraph: the facility operator has established and implemented a fuel monitoring plan as a part of the GHG Monitoring Plan specified in section 1.7(e) of this Part, has monitored fuel measurement equipment and maintained records of its proper operation by recording fuel consumption quantities at least weekly, and has compiled records of fuel consumption that are sufficient for the application of the procedures in this paragraph. For operators that apply the requirements in this paragraph, whenever quality-assured fuel consumption data are missing and there is no backup system available to record the fuel consumption, the operator must use the procedures in this paragraph to account for the consumption of fuel combusted at the unit during the missing data period. For fuels that are combusted less than 180 days in a calendar year, the operator must record fuel consumption at least daily on each day the fuel is combusted. For all other sources or fuels, the operator must record fuel consumption at least weekly.

The data capture rate for the emission year must be calculated using Equation 3.1-2 as provided in this paragraph for each unit with missing fuel consumption data:

Equation 3.1-2: Data capture rate = S / T x 100%

Where:

S = Number of fuel monitoring periods (e.g., days or weeks) in the emission year for which valid measured fuel consumption data are available.

Do not include fuel monitoring periods when the fuel was not combusted at the unit.

T = Total number of fuel monitoring periods (e.g., days or weeks) in the emission year that the fuel is combusted at the unit.

(i) Single Fuel. For missing data periods that occur when only one type of fuel is being combusted, the operator must provide substitute data for each missing data period as follows:

('a') If the fuel consumption data capture rate is equal to or greater than 95 percent during the emission year, the operator must develop an estimate based on available process data that are routinely measured and recorded at the unit (e.g., electrical load, steam production, operating hours) or fuel consumption data recorded at other upstream or downstream measurement points.

('b') If the fuel consumption data capture rate is equal to or greater than 90 percent but less than 95 percent during the emission year, the operator must calculate substitute data as the 90th percentile value of the fuel consumption data recorded for the emission year as well as the two previous emission years.

('c') If the fuel consumption data capture rate is at least 80 percent but less than 90 percent during the emission year, the operator must calculate substitute data as the 95th percentile value of the fuel consumption data recorded for the emission year as well as the two previous emission years.

('d') If the fuel consumption data capture rate is less than 80 percent during the emission year, the operator must apply as substitute data the maximum potential fuel consumption rate.

(ii) Multiple Fuels. For missing data periods that occur when two or more different types of fuel are being co-fired, the operator must provide substitute fuel flow rate data for each missing data period as follows:

('a') If the fuel consumption data for a single fuel are missing, provide substitute fuel consumption data for the missing data period using the procedures in subparagraph (i) of this paragraph.

('b') If fuel consumption data are missing for two or more of the fuels being combusted, apply the procedures in subparagraph (i) of this paragraph (as applicable) separately for each type of fuel.

('c') If the missing data substitution required in subparagraph (i) of this paragraph causes the reported heat input rate based on the combined fuel usage to exceed the maximum rated heat input of the source, adjust the substitute fuel consumption value(s) so that the reported heat input rate equals the source's maximum rated heat input.

(iii) Prorating Substitute Value. When applying the procedures in subparagraphs (i) and (ii) of this paragraph, if an individual missing data period is shorter than the fuel consumption data monitoring period, the operator must prorate the specified value for the fuel consumption data monitoring period by the missing data period. For example, for a unit with a missing data period length of one day but weekly fuel consumption monitoring schedule, the operator may divide the substitute value, estimated on a weekly basis, by the number of days the unit operates in a week to obtain the substitute value for the missing data day.

(3) Alternate Missing Data Procedure for Fuel Consumption Data. This paragraph applies to fuel combusting units that cannot use the missing data procedures in paragraphs (1) and (2) of this subdivision. If fuel consumption data are missing or invalid for a fuel combusting unit, and the total facility fuel consumption data cannot be determined at the accuracy required by this Part for the particular missing data period, the operator must substitute for each hour of missing data using the maximum potential fuel consumption rate for the unit. If fuel consumption data at the facility level or at a higher aggregated-units level are available and meet the accuracy requirements of this Part, the operator may estimate the missing unit-level fuel consumption data using available process data that are routinely measured at the facility (e.g., electrical load, steam production, operating hours) or fuel consumption data recorded at other upstream or downstream measurement points that meet the accuracy requirements of this Part.

(e) Missing Data Substitution Procedures for Steam Production. The operator of a steam-producing unit who calculates and reports emissions using Equation C-2c in 40 CFR § 98.33(a)(2) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) must apply the procedures in this subdivision to substitute for missing steam production data, unless a backup system to record steam production is available. For sources for which steam production data are not used to calculate emissions, the operator may develop an estimate using available process data that are routinely measured and recorded at the unit (e.g., electrical load, steam production, product output, operating hours) to estimate missing steam production.

If hourly steam production data are not available at the facility, the operator must record steam production data at least weekly and use the weekly records for substituting the missing steam production data. The operator must prorate the steam data using the same procedure in subparagraph (d)(2)(iii) of this section.

The data capture rate for the emission year must be calculated using Equation 3.1-3 as provided in this subdivision for each unit with a missing data period:

Equation 3.1-3: Data capture rate = S / T x 100%

Where:

S = Number of monitoring intervals (e.g., hourly, daily, or weekly) with valid measured steam production data.

T = Total number of monitoring intervals that the unit is operated in the emission year.

(1) If the steam production data capture rate is at least 90 percent during the emission year, the operator must develop an estimate using available process data that are routinely measured and recorded at the unit (e.g., electrical load, steam production, product output, and operating hours).

(2) If the steam production data capture rate is at least 80 percent but less than 90 percent during the emission year, the operator must calculate substitute data as the 90^{th} percentile value of the steam production data recorded for the emission year.

(3) If the steam production data capture rate is less than 80 percent during the emission year, the operator must substitute the highest valid steam production value recorded in all records kept according to section 1.7(a) of this Part.

(f) Procedure for Establishing Load Ranges. This subdivision is applicable to units that produce electrical output or thermal output. For a single unit, the operator must establish 10 operating load ranges, each defined in terms of percent of the maximum hourly average gross load of the unit, in gross megawatts (MW). (Do not use integrated hourly gross load in MWh.) For a cogenerating unit or other unit at which some portion of the heat input is not used to produce electricity, or for a unit for which hourly average gross load in MW is not recorded separately, the operator must use the hourly gross steam load of the unit, in pounds of steam per hour at the measured temperature (°F) and pressure (psia), instead of gross MW.

(1) Beginning with the first hour of unit operation after installation and certification of the fuel flowmeter, for each hour of unit operation the operator must record a

number, 1 through 10, that identifies the operating load range corresponding to the integrated hourly gross load of the unit(s) recorded for each unit operating hour. The operator must calculate maximum values and percentile values determined by this procedure using bias adjusted values in the load ranges. When a bias adjustment is necessary for the fuel flowmeter, the operator must apply the adjustment factor to all data values placed in the load ranges. The operator must use the calculated maximum values and percentile values to substitute for missing flow rate according to the procedures in paragraph (d)(1) of this section.

(g) Department Approved Load Range. An operator may petition the department for approval to use an alternate load-based methodology for substituting missing data to using the procedures in paragraph (d)(1) of this section. The operator must be able to prove to the satisfaction of the department that there is a direct correlation between fuel consumption and the proposed load metric. At a minimum, the operator will have a system in place that electronically measures and records fuel consumption and load at least hourly. The alternate load metric must be a metric that can be accurately measured, correlated to fuel consumption, and divided into ten operating load ranges. To verify the feasibility of the methodology the department will require at least three years of fuel consumption and load data and may request up to the maximum years of data required to be retained under section 1.7(a) of this Part.

(h) Procedure for Approval of Interim Fuel Analytical Data Collection Procedure During Equipment Breakdowns.

(1) In the event of an unforeseen breakdown of the fuel characteristic data

monitoring or fuel flow monitoring equipment used to estimate emissions under this Part, the department may authorize an operator to use an interim data collection procedure under the circumstances specified below. The operator must satisfactorily demonstrate to the department that:

(i) the breakdown may result in a loss of more than 10 percent of a fuel characteristic data element or a fuel usage data element for the emission year, and back-up sampling for affected fuel characteristics is unavailable;

(ii) the affected monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or the monitoring equipment must be replaced, and replacement equipment is not immediately available; and,

(iii) the interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning monitoring equipment.

(2) An operator seeking approval of an interim data collection procedure must, within 60 days of the monitoring equipment breakdown, submit a written request to the department that includes all of the following:

(i) the proposed start date and end date of the interim procedure;

(ii) a detailed description of what data are affected by the breakdown;

(iii) a discussion of the accuracy of data collected during the interim procedure compared with the data collected under the usual procedure used by the operator;

(iv) a demonstration that the criteria in paragraph (1) of this subdivision are satisfied, and operator certification that no feasible alternative procedure exists that would provide more accurate emissions data.

(3) The department may limit the duration of the interim data collection procedure to ensure the criteria in paragraph (1) of this subdivision are met.

(4) When reviewing an interim data collection procedure, the department shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible material misstatement under section 4.2 of this Part. Data collected pursuant to an approved interim data collection procedure shall be considered captured data for purposes of compliance with the capture rate requirements in this section.

(5) The department shall provide written notification to the operator of approval or disapproval of the interim data collection procedure within 60 days of receipt of the request, or within 30 days of receipt of any additional information requested by the department, whichever is later.

(i) Procedure for Approval of Interim Data Collection Procedure During Breakdown for Units Equipped with CEMS.

(1) In the event of an unforeseen breakdown of CEMS equipment at a combustion unit where the operator uses the Tier 4 Calculation Methodology in 40 CFR § 98.33(a)(4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) to monitor and report emissions under this Part, the operator may request approval from the department to temporarily use the Tier 1 Calculation Methodology in 40 CFR § 98.33(a)(1) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) for pipeline quality natural gas, or the Tier

2 Calculation Methodology in 40 CFR § 98.33(a)(2) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) for pipeline quality natural gas, biomass, or MSW, or the Tier 3 Calculation Methodology in 40 CFR § 98.33(a)(3) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) for other fuels, to calculate combustion emissions during the equipment breakdown period. For cement kiln units where the operator uses the Tier 4 Methodology in 40 CFR § 98.33(a)(4) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) to report both combustion and process emissions, the operator may request approval from the department to temporarily use the clinker-based process emissions calculation methodology provided in 40 CFR § 98.83(d) (Amended April 25, 2024) (see Table 1, section 200.9 of this Title). The operator must satisfactorily demonstrate to the department that:

(i) the breakdown will result in a loss of more than 10 percent of the concentration, flow rate, or other information used to calculate and report annual emissions for the emission year, and that back-up monitoring is unavailable;

(ii) the affected monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or the monitoring equipment must be replaced, and replacement equipment is not immediately available; and,

(iii) the interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning monitoring equipment.

(2) The operator must collect fuel samples and comply with all applicable requirements of the Tier 2 or Tier 3 Calculation Methodology in 40 CFR § 98.33(a)(2) or (3)

(Amended May 14, 2024) (see Table 1, section 200.9 of this Title), as modified by section 2.7 of this Part, during the equipment breakdown period. Fuel characteristics data provided by the fuel suppliers can be used if available. The operator must, within 60 days of the monitoring equipment breakdown, submit a written request to the department that includes all the following information:

(i) the proposed start date and end date of the interim procedure, including a demonstration that the interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning equipment;

(ii) a detailed description of what data are affected by the breakdown; and,

(iii) an interim monitoring plan that meets the requirements of the Tiers 2 and 3 Calculation Methodologies in 40 CFR § 98.33(a)(2) or (3) (Amended May 14, 2024) (see Table 1, section 200.9 of this Title) as applicable by fuel type in section 2.7 of this Part, and, if applicable, the clinker-based process emissions calculation procedure in 40 CFR § 98.83(d) (Amended April 25, 2024) (see Table 1, section 200.9 of this Title) used to report cement kiln process emissions.

(3) The department may limit the duration of the interim data collection procedure to ensure the criteria in paragraph (1) of this subdivision are met.

(4) The department shall provide written notification to the operator of approval or disapproval of the interim data collection procedure within 60 days of receipt of the request, or within 30 days of receipt of any additional information requested by the department, whichever is later.

Subpart 253-4 Requirements for Verification of Greenhouse Gas Emissions Data Reports and Requirements Applicable to Emissions Data Verifiers; Requirements for Accreditation of Emissions Data

253-4.1 Requirements for Verification of Emissions Data Reports

An emission source who is subject to verification must obtain the services of an accredited verification body for purposes of verifying each emissions data report submitted under this Part, as specified in section 1.4(c) of this Part, unless exempt from verification under section 1.2(l)(2) of this Part.

(a) Annual Verification.

(1) Emission Sources that are required to obtain verification services, pursuant to section 1.4(c) of this Part, must meet the full verification requirements, pursuant to section 4.2 of this Part, in the first year of each continuous three-year period in which verification services are required. Upon receiving a positive verification statement, or statements, if applicable, under full verification requirements, the reporting entity may choose to obtain less intensive verification services as defined pursuant to this Part, for the remaining years of the continuous three-year period. Emission sources subject to this section are also required to obtain full verification services if any of the following apply:

(i) there has been a change in the verification body;

(ii) an adverse verification statement or qualified positive verification statement was issued for the previous year for either emissions data or product data, or both;

(iii) a change of operational control of the emission source occurred in the previous year.

(iv) Nothing in this paragraph shall be construed as preventing a verification body from performing a full verification in instances where there are changes in sources or emissions or industrial products. The verification body must provide information on the causes of the emission changes and justification in the verification report if a full verification was not conducted in instances where the total reported GHG emissions differ by greater than 25 percent relative to the preceding year's emissions data report.

(2) Emission sources subject to annual verification under this section shall not use the same verification body or verifier(s) for a period of more than six consecutive years, which includes any verifications conducted under this Part and for other third-party verifications, validations, or audits conducted under impartiality provisions substantively equivalent to section 4.4 of this Part, which may include third-party certification of environmental management systems to the standard of ISO 14001:2015 Environmental management systems — Requirements with guidance for use Published (Edition 3, 2015) (see Table 1, section 200.9 of this Title) or of third-party certification of energy management systems to the standard of ISO 50001:2018 Energy management systems —Requirements with guidance for use Published (Edition 2, 2018) (see Table 1, section 200.9 of this Title). This limitation applies only to those third-party verifications, validations, or audits that include the scope of activities or operations under the department identification number for the emissions data report.

(i) The six-year period begins on the date the reporting entity or its agent first contracts for any third-party verifications, validations, or audits under any protocols, including department verification services, for the scope of activities or operations under the department identification number for the emissions data report, and ends on the date the final verification statement is submitted. Verification bodies may not provide verification services if the six-year period ends prior to 60 days after the emissions data report is certified by the emission source, unless a verification plan is agreed to by the emission source, the verification body, and the department. If the six-year time limit is exceeded, the emission source must engage a different verification body and meet the verification deadline. Even if these services are provided before the verification body or verifiers have received department accreditation, the six-year period still begins when these services are contracted for if accreditation is later received.

(ii) The six-year limit also applies to verification bodies and verifiers providing the department or any other third-party verifications, validations, or audits that include the scope of activities or operations under the department identification number for the emissions data report and does not reset upon a change in emission source ownership or operational control.

(3) If an emission source is required or elects to contract with another verification body or verifier(s), the emission source may contract verification services from the previous verification body or verifier(s) only after not using the previous verification body or verifier(s) for at least three years.

(i) If an emission source is required to select a new verification body to verify an emissions data report(s) that has been set aside pursuant to section 4.2(e) of this

Part, the emission source may continue to contract for verification services with its current verification body, subject to the six-year time limit.

(4) If an owner or operator of an emission source meets the requirements for cessation of reporting pursuant to section 1.2(n) or 1.2(o) of this Part, the owner or operator must continue to obtain the services of an accredited verification body for purposes of verifying the emissions data report for the year in which the facility's GHG-emitting processes and operations ceased to operate. Verification is not required for the emissions data report of the first full year of non-operation that follows. If the emission source was not subject to verification before meeting the cessation of reporting requirements pursuant to section 1.2(n) or 1.2(o) of this Part, verification is not required under this section for the year in which the facility's GHG-emitting processes and operations ceased to operate.

253-4.2 Requirements for Verification Services

Verification services shall be subject to the following requirements:

(a) Notice of Verification Services. After the department has provided a determination that the potential for a conflict-of-interest is acceptable as specified in section 4.4(f) of this Part and that verification services may proceed, the verification body shall submit a notice of verification services to the department. The verification body may begin verification services for the reporting entity after the notice is received by the department but must allow 14 days advance notice of the site visit unless an earlier date is approved by the department in writing. If the conflict-of-interest statement and the notice of verification services are submitted together, verification services cannot begin until 10 days after the department has deemed acceptable the potential for conflict-of-interest as specified in section 4.4(f) of this Part. Verification services may not begin until the emission source certifies the emissions data report. The notice shall include the following information:

(1) A list of the staff who will be designated to provide verification services as a verification team, including the names of each designated staff member, the lead verifier, and all subcontractors, and a description of the roles and responsibilities each member will have during verification.

(2) Documentation that the verification team has the skills required to provide verification services for the reporting facility. This shall include a demonstration that a verification team includes at least one member accredited as a sector-specific verifier that is not also the independent reviewer, when required by subparagraph (i) through (iii) of this paragraph:

(i) for providing verification services to a supplier of petroleum products or biofuels; a supplier of coal; a transporter of solid waste; a supplier of natural gas, natural gas liquids, or liquefied petroleum gas, at least one verification team member must be accredited by the department as a transactions specialist;

(ii) for providing verification services to the operator of a petroleum refinery, hydrogen production unit or facility, or petroleum and natural gas system listed in section 1.2(k) of this Part, at least one verification team member must be accredited by the department as an oil and gas systems specialist;

(iii) for providing verification services to the operator of a facility engaged in anaerobic digestion and liquid waste storage, cement production, glass production, electronics manufacturing, lime manufacturing, iron and steel production, solid waste management, or lead production, at least one verification team member must be accredited by the department as a process emissions specialist.

(3) General information on the reporting entity, including:

(i) the name of the reporting entity and the facilities and other locations that will be subject to verification services, reporting entity contact, address, telephone number, and e-mail address;

(ii) the industry sector and the NAICS code for the reporting facility;

(iii) the date(s) of the on-site visit, if required in section 4.1(a)(1) of this Part, with facility address and contact information;

(iv) a brief description of expected verification services to be performed, including expected completion date.

(4) If any of the information under paragraphs (1) or (3) of this subdivision changes after the notice is submitted to the department, the verification body must notify the department by submitting an updated conflict-of-interest self-evaluation form and updated notice of verification services as soon as the change is made. The conflict-of-interest must be reevaluated pursuant to section 4.4 of this Part and the department must approve any changes in writing.

(b) Verification Service Components. Verification services shall include, but are not limited to, the following:

(1) Verification Plan. The verification team shall develop a verification plan based on the following:

(i) Information from the reporting entity. Such information shall include:

(‘a’) information to allow the verification team to develop a general understanding of facility or emission source boundaries, operations, emission sources, product data, and electricity or fuel transactions as applicable;

(‘b’) information regarding the training or qualifications of personnel involved in developing the emissions data report;

(‘c’) description of the specific methodologies used to quantify and report GHG emissions, product data, electricity and fuel transactions, and associated data as needed to develop the verification plan;

(‘d’) information about the data management system used to track GHG emissions, product data, electricity and fuel transactions, and associated data as needed to develop the verification plan;

(‘e’) previous verification reports.

(ii) Timing of verification services. Such information shall include:

(‘a’) dates of proposed meetings and interviews with reporting facility personnel;

(‘b’) dates of proposed site visits;

(‘c’) types of proposed document and data reviews;

(‘d’) expected date for completing verification services.

(2) Planning Meetings with the Emission Source. The verification team shall discuss with the emission source the scope of the verification services and request any information and documents needed for initial verification services. The verification team shall

create a draft sampling plan and verification plan prior to the site visit during full verification. The verification team shall also review the documents submitted and plan and conduct a review of original documents and supporting data for the emissions data report.

(3) Site Visits. At least one accredited verifier in the verification team, including the sector-specific verifier, if applicable, shall at a minimum make one site visit, during each year full verification is required, to each facility for which an emissions data report is submitted. The verification team member(s) shall visit the headquarters or other location of central data management when the reporting entity is a retail provider, marketer, or fuel supplier. During the site visit, the verification team member(s) shall conduct the following:

(i) The verification team member(s) shall check that all sources specified in sections 2.1 to 2.22 of this Part, as applicable to the emission source and subject to verification, are identified appropriately.

(ii) The verification team member(s) shall review and understand the data management systems used by the reporting entity to track, quantify, and report GHG emissions and, when applicable, product data, and electricity and fuel transactions. The verification team member(s) shall evaluate the uncertainty and effectiveness of these systems.

(iii) The verification team shall carry out tasks that, in the professional judgment of the team, are needed in the verification process, including the following:

('a') interviews with key personnel, such as process engineers and metering experts, as well as staff involved in compiling data and preparing the emissions data report;

('b') making direct observations of equipment for data sources and equipment supplying data for sources determined in the sampling plan to be high risk;

('c') assessing conformance with measurement accuracy, data capture, and missing data substitution requirements, as well as department approved alternate methods, temporary methods, and department approved meter calibration postponements;

('d') reviewing financial transactions to confirm fuel, feedstock, product data and electricity purchases and sales, and confirming the complete and accurate reporting of required data such as facility fuel suppliers, fuel quantities delivered, and if fuel was received directly from an interstate pipeline.

(4) Review of Emission Source's Operations, Product Data and Emissions. The verification team shall review facility operations to identify applicable GHG emission sources and product data. This shall include a review of the emissions inventory and each type of emission source to ensure that all sources listed in sections 2.1 to 2.22 of this Part are properly included in the emissions data report. This shall also include a review of the product data to ensure that all product data listed in sections 2.1 to 2.22 of this Part are included in the emissions data report as required by this Part. The verification team shall also ensure that the reported current primary and any secondary (if reported) NAICS codes reported pursuant to section 1.5(c) of this Part accurately represent the NAICS-associated Activities listed in Table 2-9 in section 2.22 of this Part. Review of these NAICS codes and associated activities must be documented in the verification team's sampling plan.

(5) Other Emission Source Information. Emission sources shall make available

to the verification team all information and documentation used to calculate and report emissions, product data, fuels and electricity transactions, and other information required under this Part, as applicable.

(6) Sampling Plan. As part of confirming emissions data, product data, electricity transactions, or fuel transactions, the verification team shall develop a sampling plan that meets the following requirements:

(i) The verification team shall develop a sampling plan based on a strategic analysis developed from document reviews and interviews to assess the likely nature, scale, and complexity of the verification services for an emission source. The analysis shall review the inputs for the development of the submitted emissions data report, the rigor and appropriateness of data management systems, and the coordination within the emission source's organization to manage the operation and maintenance of equipment and systems used to develop emissions data reports.

(ii) The verification team shall include in the sampling plan a ranking of emission sources by amount of contribution to total CO_2e emissions for the emission source, and a ranking of emission sources with the largest calculation uncertainty. The verification team shall also include in the sampling plan a ranking of the product data by units specified in the appropriate section of this Part and a ranking of the product data with the largest uncertainty. As applicable and deemed appropriate by the verification team, fuel and electricity transactions shall also be ranked or evaluated relative to the amount of fuel or power exchanged and uncertainties that may apply to data provided by the emission source including risk of incomplete reporting.

(iii) The verification team shall include in the sampling plan a qualitative narrative of uncertainty risk assessment in the following areas as applicable under sections 2.1 to 2.22 and 3.1 of this Part:

('a') data acquisition equipment;

('b') data sampling and frequency;

('c') data processing and tracking;

('d') emissions calculations;

('e') product data;

('f') data reporting; and

('g') management policies or practices in developing emissions data reports.

(iv) After completing the analyses required by subparagraphs (i) through (iii) of this paragraph, the verification team shall include in the sampling plan a list which includes the following:

('a') emission sources, product data, and/or transactions that will be targeted for document reviews, and data checks as specified in paragraph (8) of this subdivision, and an explanation of why they were chosen;

('b') methods used to conduct data checks for each source, product data, or transaction;

('c') a summary of the information analyzed in the data checks and document reviews conducted for each emission source, product data, or transaction targeted.

The sampling plan list must be updated and finalized prior to the completion of verification services. The final sampling plan must describe in detail how the identified risks were addressed during the verification.

(v) The verification team shall revise the sampling plan to describe tasks completed by the verification team as information becomes available and potential issues emerge with material misstatement or nonconformance with the requirements of this Part.

(vi) The verification body shall retain the sampling plan in paper, electronic, or other format for a period of not less than 10 years following the submission of each verification statement. The sampling plan shall be made available to the department upon request.

(vii) The verification body shall retain all material received, reviewed, or generated to render a verification statement for a reporting entity for no less than 10 years. The documentation must allow for a transparent review of how a verification body reached its conclusion in the verification statement.

(7) Data Checks. To determine the reliability of the submitted emissions data report, the verification team shall use data checks. Such data checks shall focus on the largest and most uncertain estimates of emissions, product data and fuel and electricity transactions, and shall include the following:

(i) the verification team shall use data checks to ensure that the appropriate methodologies and emission factors have been applied for the emission sources, fuel and electricity transactions covered under sections 2.1 to 2.22 and 3.1 of this Part;

(ii) the verification team shall use data checks to ensure the accuracy of product data reported under sections 2.1 to 2.22 of this Part;

(iii) the verification team shall choose data checks for emission sources, product data, and fuel and electricity transactions data, as applicable, based on their relative contributions to emissions and the associated risks of contributing to material misstatement or nonconformance, as indicated in the sampling plan;

(iv) the verification team shall use professional judgment in the number of data checks required for the team to conclude with reasonable assurance whether the total reported emissions and industrial product data are free of material misstatement. At a minimum, data checks must include the following:

('a') tracing data in the emissions data report to its origin;

('b') looking at the process for data compilation and collection;

('c') recalculating emission estimates to check original calculations;

('d') reviewing calculation methodologies used by the emission source for conformance with this Part; and

('e') reviewing meter and fuel analytical instrumentation measurement accuracy and calibration for consistency with the requirements of section 1.4(g) of this Part.

(v) As applicable, the verification team shall review the following information when conducting data checks for product data:

('a') product inventory and stock records;

('b') product sales records and contracts;

('c') onsite and offsite product delivery records;

('d') purchase and delivery records for inputs to product(s);

('e') product measurement records; and

('f') other information or documentation that provides financial or direct measurement information about total product(s) reported.

(vi) The verification team is responsible for ensuring via data checks that there is reasonable assurance that the emissions data report conforms to the requirements of this Part. In addition, and as applicable, the verifier's review of conformance must confirm the following information is correctly reported:

('a') for facilities that combust natural gas, natural gas supplier customer account number, service account identification number, or other primary account identifier(s) reported pursuant to section 2.7(l) of this Part;

('b') for suppliers of natural gas, end-user names, account identification numbers, and natural gas deliveries in MMBtu, reported pursuant to section 2.17(d)(4) of this Part;

('c') energy generation and disposition information reported pursuant to sections 1.5(d), 2.5(a), 2.5(b) of this Part and electricity and thermal energy purchases and acquisitions reported pursuant to sections 1.5(d)(1) and (2) of this Part, if any of the following apply:

('1') the facility belongs to an industry sector (e.g., reported a NAICS code) listed in Table 2-9 in section 2.22 of this Part;

(vii) The verification team shall compare its own calculated results with the reported data in order to confirm the extent and impact of any omissions and errors. Any discrepancies must be investigated. The comparison of data checks must also include a narrative to indicate which sources, product data, and transactions were checked, the types and quantity of data that were evaluated for each source, product data, and transaction, the percentage of reported emissions covered by the data checks, the percentage of product data covered by the data checks, and any separate discrepancies that were identified in emissions data or product data.

(8) Emissions Data Report Modifications. As a result of data checks by the verification team and prior to completion of a verification statement(s), the emission source must fix all correctable errors that affect emissions or industrial product data in the submitted emissions data report and submit a revised emissions data report to the department. Failure to do so will result in an adverse verification statement. Failure to fix misreported data that do not affect emissions or industrial product data represents a nonconformance with this Part but does not, absent other errors, result in an adverse verification statement. The emission source shall maintain documentation to support any revisions made to the initial emissions data report. Documentation for all emissions data report submittals shall be retained by the emission source for ten years pursuant to section 1.7 of this Part.

The verification team shall use professional judgment in the determination of correctable errors as defined pursuant to this Part, including whether differences are not errors but result from truncation or rounding or averaging.

If the verification team determines that the reported NAICS code(s) reviewed pursuant to paragraph (4) of this subdivision is inaccurate, and the emission source does not submit a revised emissions data report to correct the current NAICS code(s), the result will be an adverse verification statement.

The verification team must document the source of any difference identified, including whether the difference results in a correctable error or whether the difference does not require further investigation because it is the result of truncation, rounding, or averaging.

(9) Findings. To verify that the emissions data report is free of material misstatements, the verification team shall make its own determination of emissions for checked sources and product data for checked data and shall determine whether there is reasonable assurance that the emissions data report does not contain a material misstatement in GHG emissions reported for the emission source, on a CO_2 equivalent basis and/or a material misstatement in product data for the emission source, using the units required by the applicable parts of this Part. To assess conformance with this Part, the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirements of this Part and ensure that other requirements of this Part are met.

(10) Log of Issues. The verification team must keep a log of any issues identified in the course of verification activities that may affect determinations of material misstatement and nonconformance, whether identified by the verifier or by the reporter regarding the original or subsequent certified reports or identified by department staff. The issues log must identify the regulatory section related to the nonconformance or potential nonconformance, if applicable, and indicate if the issues were corrected by the emission source prior to completing the verification. Any other concerns that the verification team has

with the preparation of the emissions data report, including with any limited alternative emissions calculations, must be documented in the issues log and communicated to the emission source during the course of verification activities. The log of issues must indicate whether each issue has a potential bearing on material misstatement, nonconformance, or both and whether an adverse verification statement may result if not addressed.

(11) Material Misstatement Assessment. Assessments of material misstatement are conducted independently on total reported emissions and total reported industrial product data (units from the applicable sections of this Part).

(i) In assessing whether an emissions data report contains a material misstatement, the verification team must separately determine whether the total reported emissions and total reported industrial product data contain a material misstatement using Equation 4.2-1 or 4.2-2 as provided in this subparagraph:

Equation 4.2-1:

$$Percent\ error\ (emissions) = \sum \frac{[Discrepancies + Omissions + Misreporting] * 100\%}{Total\ reported\ covered\ emissions}$$

Or

Equation 4.2-2:

$$Percent\ error\ (product\ data) = \sum \frac{[Discrepancies + Omissions + Misreporting] * 100\%}{Total\ industrial\ product\ data}$$

Where:

Discrepancies means any differences between the reported emissions or industrial product data and the verifier’s review of emissions or industrial product data for a data source or product data subject to data checks in paragraph (8) of this subdivision.

Omissions means any emissions or industrial product data the verifier concludes must be part of the emissions data report but were not included by the reporting entity in the emissions data report.

Misreporting means duplicate, incomplete or other emissions the verifier concludes should, or should not, be part of the emissions data report or duplicate or other product data the verifier concludes should not be part of the emissions data report.

Total reported emissions or industrial product data means the total annual reporting entity emissions or total reported industrial product data for which the verifier is conducting a material misstatement assessment.

For instances in which a reporting entity reports industrial product data subject to data checks under paragraph (8) of this subdivision in different units of measurement or reports industrial product data under section 2.12 of this Part, the verifier must conduct a material misstatement evaluation according to the requirements of subparagraphs (iv) and (v) of this paragraph, respectively.

(ii) When evaluating a material misstatement or misstatements, verifiers must deem correctly substituted missing data to be accurate, regardless of the amount of missing data.

(iii) The omissions variable described in subparagraph (i) of this paragraph does not apply to excluded industrial product data as described in section 1.4(h) of this Part, such that excluded industrial product data is not considered in the material misstatement assessment.

(iv) Beginning with 2026 data reported in 2027, if multiple types of industrial product data are reported with different units of measurement, the verifier shall conduct a separate material misstatement evaluation for each product, except as provided in subparagraph (v) of this paragraph.

(v) Beginning with 2026 data reported in 2027, the verifier shall conduct a separate material misstatement evaluation for industrial product data reported pursuant to section 2.12 of this Part. If a facility reports industrial product data under section 2.12 of this Part, and another section(s) that requires reporting industrial product data, three (or more) separate industrial product data material misstatement assessments must be completed, and three (or more) separate product data verification statements must be issued.

(12) Review of Missing Data Substitution. If a source selected for a data check was affected by a loss of data used to calculate GHG emissions for the emission year:

(i) The verification team shall confirm that the reported emissions for that source were calculated using the applicable missing data procedures, or that an approved interim data collection procedure was used for the source.

(ii) If 20 percent or less of any single data elements used to calculate emissions are missing, and emissions are correctly calculated using the missing data requirements in sections 2.1 to 2.22 and 3.1 of this Part, these emissions will be considered accurate and as meeting the reporting requirements for that source.

(iii) If greater than 20 percent of any single data element used to calculate emissions are missing or any combination of data elements are missing that would result in more than five percent of a facility's emissions being calculated using missing data requirements in sections 2.1 to 2.22 and 3.1 of this Part, the verifier must include a finding of nonconformance with the required emissions calculation methodology as part of the verification statement.

(iv) The verifier must note the date, time and source of any missing data substitutions discovered during the course of verification in the verification report.

(13) Review of Product Data. The verifier's review of product data must include the following, where applicable.

(i) Verifiers must confirm that data substitutions were not used for industrial product data.

(ii) Verifiers must confirm that all industrial product data specified in sections 2.1 to 2.22 of this Part conforms to the reporting requirements of this Part, including, but not limited to, meeting the applicable product data definitions, and meter accuracy and calibrations requirements. Industrial product data subject to this confirmation include underlying product data that are measured and reported to support the calculation of other industrial product data. Verifiers shall describe in their sampling plan how they determined that reported industrial product data conforms to the requirements of this Part.

(c) Verification Services Requirements. Completion of verification services must include:

(1) Verification Statement. Upon completion of the verification services specified in subdivision (b) of this section, the verification body shall complete an emissions data verification statement and product data verification statement(s) and provide those statements to the reporting entity and the department by the applicable verification deadline specified in section 1.4(c) of this Part. Before the emissions data verification statement and product data verification statement(s) are completed, the verification body shall have the verification services and findings of the verification team independently reviewed within the verification body by an independent reviewer who is a lead verifier not involved in services for that reporting entity during that year.

(2) Independent Review. The independent reviewer shall serve as a final check on the verification team's work to identify any significant concerns, including:

(i) errors in planning,

(ii) errors in data sampling, and

(iii) errors in judgment by the verification team that are related to the draft verification statement.

The independent reviewer must maintain independence from the verification services by not making specific recommendations about how the verification services should be conducted. The independent reviewer will review documents applicable to the verification services provided and identify any failure to comply with requirements of this Part or with the verification body's internal policies and procedures for providing verification services. The independent reviewer must concur with the verification findings before the verification statement(s) can be issued.

(3) Completion of Findings and Verification Report. The verification body is required to provide each reporting entity with the following:

(i) A detailed verification report, which shall at a minimum include:

(‘a’) a detailed description of the facility or emission source, including all emissions and product data sources and boundaries;

(‘b’) a detailed description of data acquisition, tracking and emission calculation/product data systems;

(‘c’) the verification plan;

(‘d’) the detailed comparison of the data checks conducted during verification services for emissions and product data sources;

(‘e’) the log of issues identified in the course of verification activities and their resolution;

(‘f’) any qualifying comments on findings during verification services; and

(‘g’) the calculation performed in subparagraph (b)(12)(i) of this section for emissions and product data.

The verification report shall be submitted to the emission source at the same time as or before the final emissions data verification statement and product data verification statement(s) are submitted to the department. The detailed verification report shall be made available to the department upon request.

(ii) The verification team shall have a final discussion with the emission source explaining its findings and notify the emission source of any unresolved issues noted in the issues log before the verification statement(s) are finalized.

(iii) The verification body shall provide the verification statement(s) to the emission source and the department, attesting whether the verification body has found the submitted emissions data report to be free of material misstatements, and whether the emissions data report is in conformance with the requirements of this Part. For every qualified positive verification statement, the verification body shall explain the nonconformances contained within the emissions data report and shall cite the section(s) in this Part that corresponds to the nonconformance and why the nonconformances do not result in a material misstatement. For every adverse verification statement, the verification body must explain all nonconformances and material misstatements leading to the adverse verification statement and shall cite the section(s) in this Part that corresponds to the nonconformance(s) and material misstatements.

(iv) The lead verifier in the verification team shall attest that the verification team has carried out all verification services as required by this Part, and the lead verifier who has conducted the independent review of verification services and findings shall attest to their independent review on behalf of the verification body and their concurrence with the verification findings.

(‘a’) The lead verifier must attest in the verification statement, in writing, to the department as follows:

“I certify under penalty of the laws of the State of New York that the verification team has carried out all verification services as required by Part 253 of Title 6 of the New York Codes, Rules and Regulations.”

('b') The lead verifier independent reviewer who has conducted the independent review of verification services and findings must attest in the verification statement, in writing, to the department as follows:

"I certify under penalty of the laws of the State of New York that I have conducted an independent review of the verification services and findings on behalf of the verification body as required by Part 253 of Title 6 of the New York Codes, Rules and Regulations and that the findings are true, accurate, and complete."

(4) Adverse Verification Statement and Petition Process. Prior to the verification body providing an adverse verification statement for emissions or product data, or both, to the department, the verification body shall notify the emission source and the emission source shall be provided at least 14 days to modify the emissions data report to correct any material misstatements or nonconformance found by the verification team. The verification body must provide notice to the department of the potential for an adverse verification statement(s) at the same time it notifies the reporting entity and include a preliminary issues log. The modified report and verification statement(s) must be submitted to the department before the verification deadline, even if the reporting entity makes a request to the department as provided in subparagraph (i) of this paragraph.

(i) If the emission source and the verification body cannot reach agreement on modifications to the emissions data report that result in a positive verification statement or qualified positive verification statement for the emissions or product data because of a disagreement on the requirements of this Part, the emission source may petition the department before the verification deadline and before the verification statement is submitted to make a final decision as to the verifiability of the submitted emissions data report. The emission source may petition either emissions or product data verification statements, or both. At the same time that the emission source petitions the department, the emission source must submit all information it believes is necessary for the department to make a final decision.

(ii) The department shall make a final decision no later than October 10 following the submission of a petition pursuant to subparagraph (i) of this paragraph. If at any point the department requests information from the verification body or the emission source, the information must be submitted to the department within 10 days. The department will notify both the emission source and the verification body of its determination, which may also include an assigned emissions level calculated pursuant to paragraph (5) of this subdivision, if applicable.

(5) Assigned Emissions Level. When an emission source fails to receive a verification statement for an emission year by the applicable deadline or receives an adverse emissions data verification statement, the department shall develop an assigned emissions level for the emission year for the emission source. Within 10 days of a written request by the department, the verification body (if applicable) shall provide any available verification services information or correspondence related to the emissions data. Within 10 days of a request by the department, the emission source shall provide the data that is required to calculate GHG emissions for the emission source according to the requirements of this Part, the preliminary or final detailed verification report prepared by the verification body (if applicable), and other information requested by the department, including the operating days

and hours of the emission source during the emission year. The emission source shall also make available personnel who can assist the department's determination of an assigned emissions level for the emission year.

(i) In preparing the assigned emissions level for the emission source, the department shall consider at a minimum the following information:

('a') the number, types and days and hours of operation of the sources operated by the emission source for the emissions emission year;

('b') any previous emissions data reports submitted by the emission source and verification statements rendered for those reports;

('c') the potential maximum fuel and process material input and output capacities for the emission source's emission sources during operating hours;

('d') for electric power entities, wholesale and retail transactions that would affect an assigned emissions level, for the applicable emission year and for previous years;

('e') emissions, electricity transactions, fuel use, or product output information reported to the department or other State, Federal, or local agencies.

(ii) In preparing the assigned emissions level for the reporting entity, the department may use the following methods, as applicable:

('a') the sector-specific calculation methodologies in this Part;

('b') in the event of missing data, the department will rely on the missing data provisions of this Part; and

('c') any information reported under this Part for this emission year and past years.

(iii) The department shall assign the emissions level for the emission source using the best information available, including the information in subparagraph (i) of this paragraph and methods in subparagraph (ii) of this paragraph, as applicable. The department shall include an assigned emissions level in the decision made pursuant to subparagraph (4)(ii) of this subdivision, if applicable.

(d) Revision of Verification Statement Submission. Upon provision of the verification statement, or statements, if applicable, to the department, the emissions data report shall be considered final. No changes shall be made to the report as submitted to the department, and all verification requirements of this Part shall be considered complete except in the circumstance specified in subdivision (e) of this section.

(e) Re-Verification Upon Department Findings. If the department finds a high level of conflict-of-interest existed between a verification body and an emission source, an error is identified, or an emissions data report that received a positive or qualified positive verification statement fails a department audit, the department may set aside the positive or qualified positive verification statement issued by the verification body and require the emission source to have the emissions data report re-verified by a different verification body within 90 days. This subdivision applies to verification statements for emissions and product data. In instances where an error to an emissions data report is identified and determined by the department to not affect the emissions or industrial product data, the change may be made without a set aside of the positive or qualified positive verification statement.

(f) Provision of Emissions Report Data. Upon request by the department, the emission source shall provide the data used to generate an emissions data report, including all data available to a verifier in the conduct of verification services, within 14 days.

(g) Provision of Full Verification Report and Supporting Material. Upon request of the department, the verification body shall provide the department the full verification report given to the emission source, as well as the sampling plan, contracts for verification services, and any other supporting documents and calculations, within 14 days.

(h) Department Audits. Upon written notification by the department, the verification body shall make itself and its personnel available for a department audit.

(i) Verifying Biomass-derived Fuels. In the absence of certification of the biomass-derived fuel by an accredited certifier of biomass-derived fuels, the verification body is subject to the requirements of this Subpart as modified in this subdivision when verifying biomass-derived fuel:

(1) General biomass-derived fuel verification requirements. The following requirements apply to the biomass-derived fuel verification:

(i) Annual Verification. Biomass-derived fuel is subject to annual verification as specified in section 1.4(c) of this Part.

(ii) Verification Services for Biomass-derived Fuels. When an emission source reports that biomass-derived fuels are used, the biomass-derived fuels must be considered when providing all verification services required under subdivision (b) of this section. The verification team must:

(‘a’) Review the emission source’s reported biomass-derived fuel emissions to ensure the biomass-derived fuels are properly listed in the emissions data report as required in section 1.4(f) of this Part.

(‘b) Conduct separate data checks that are consistent with the requirements in subparagraph (2)(iv) of this paragraph for the fuel type being verified using the following documentation, as appropriate: the invoice, nomination, scheduling, storage, in-kind fuel purchase, allocation, transportation and balancing reports, or other documents used as evidence of the fuel delivery.

(‘1’) The emission source may arrange for the documentation to be supplied directly to the verifier if there are confidentiality issues that would prevent these documents from being made available to the emission source.

(iii) Completion of Verification Services for Biomass-derived Fuels.

(‘a’) All information used for the verification of biomass-derived fuels must be included in the independent review as required in paragraph (c)(2) of this section.

(‘b’) Conformance for biomass-derived fuels is evaluated against the requirements of this Part.

(2) Specific biomass-derived fuel verification requirements.

(i) For wood residuals recovered from construction and demolition debris, agricultural waste, and forest-derived wood and wood waste, the verifier must determine the emission source met the requirements of section 1.4(f) of this Part.

(ii) For biodiesel and fuel ethanol, the verifier must determine that the emission source met the requirements of section 1.4(f) of this Part and the following requirements:

('a') At combustion sources that purchase biomass-derived fuels, verify records to demonstrate that volume purchased equals or exceeds volume reported.

('b') At combustion sources that produce their own fuel, verify:

('1') that raw material is sufficient to produce the quantity of fuel reported;

('2') that the facility has the ability to produce the biomass-derived fuel reported;

('3') that the emissions from the fuel are accurately reported and do not lead to the underreporting of fossil fuel emissions.

(iii) For municipal solid waste and tires, the verifier must determine the emission source met the requirements of section 1.4(f) of this Part.

(iv) For biomethane and biogas, the verifier must:

('a') examine all nomination, invoice, scheduling, allocation, transportation, storage, in-kind fuel purchase and balancing reports from the producer to the emission source and have reasonable assurance that the emission source is receiving the identified fuel;

('b') determine that no fossil-derived fuel is used to supplement the biomass-derived fuel deliveries except for documented fuel purchases to avoid loss of metered volumes in connection with the transportation of the biomethane to the emission source;

('c') ensure any discrepancies in the fuel volumes, heat values and/or energies will be carried over into the evaluation of material misstatement for the emission source.

253-4.3 Accreditation Requirements for Verification Bodies, Lead Verifiers, and Verifiers of Emissions Data Reports.

(a) Accreditation Requirements. The accreditation requirements specified in this section shall apply to all verification bodies, lead verifiers, and verifiers that wish to provide verification services under this Part.

(b) Accreditation from Outside New York. Upon receiving an application, the department may issue accreditation to verification bodies, lead verifiers, and verifiers that have active accreditation or recognition as a third-party verifier under the CARB's Mandatory Reporting of Greenhouse Gas Emissions program pursuant to the procedures referred to in section 95352 of title 17 of the California Code of Regulations (January 1, 2022) (see Table 1, section 200.9 of this Title), or the ANSI National Accreditation Board Accreditation Program for Greenhouse Gas Validation/Verification Bodies pursuant to the standard ISO 14065:2020 General principles and requirements for bodies validating and verifying environmental information Published (Edition 3, 2020) (see Table 1, section 200.9 of this Title). Provided that the verification body, lead verifier or verifier demonstrate to the department’s satisfaction, knowledge of the relevant methods and protocols in this Part. Accreditation may be limited to certain types or sources of emissions. The department may impose additional training and requirements on verifiers, and verification bodies originally accredited outside of New York.

(c) Requirements for Accreditation. The department may issue accreditation to verification bodies, lead verifiers, and verifiers that meet the requirements specified in this section.

(1) Verification Body Accreditation Application. To apply for accreditation as a verification body, the applicant shall submit the following information to the department:

(i) A list of all verification staff and a description of their duties and qualifications, including department-accredited verifiers on staff. The applicant shall demonstrate staff qualifications by listing each person's education, experience, professional licenses, and other pertinent information.

('a') A verification body shall employ and retain at least two verifiers that have been accredited as lead verifiers, as specified in paragraph (2) of this subdivision. American National Standards Institute (ANSI) accredited verification bodies are exempt from this requirement.

('b') A verification body shall employ and retain at least five total full-time staff.

(ii) The applicant shall provide a list of any judicial proceedings, enforcement actions, or administrative actions filed against the body within the previous five years, with an explanation as to the nature of the proceedings.

(iii) The applicant shall provide documentation that the proposed verification body maintains a minimum of four million U.S. dollars of professional liability insurance and must maintain this insurance for three years after completing verification services. Neither general nor umbrella liability policies can be used for the professional liability insurance minimum for the purposes of this provision.

(iv) The applicant shall provide a demonstration that the verification body has policies and mechanisms in place to prevent conflicts of interest and to identify and resolve potential conflict-of-interest situations if they arise. The applicant shall provide the following information:

('a') identification of services provided by the verification body, the industries that the body serves, and the locations where those services are provided;

('b') a detailed organizational chart that includes the verification body, its management structure, and any related entities;

('c') the verification body's internal conflict-of-interest policy that identifies activities and limits to monetary or non-monetary gifts that apply to all employees and procedures to monitor, assess, and notify the department of potential conflicts of interest.

(v) The applicant shall provide a demonstration that the verification body has procedures or policies to support staff technical training as it relates to verification. This training shall include participating in all department-approved verifier training on an ongoing basis as it becomes available.

(vi) The verification body shall notify the department within 30 days of when it no longer meets the requirements for accreditation as a verification body in paragraph (1) of this subdivision. The verification body may request that the department provide additional time to hire additional staff to meet the requirements of this section.

(2) Lead Verifier Accreditation Application. To apply for accreditation as a lead verifier, the applicant shall submit documentation to the department that provides the evidence specified in subparagraphs (i), and (ii), or (iii) of this paragraph:

(i) evidence that the applicant meets the criteria in paragraph (3) of this subdivision; and,

(ii) evidence that the applicant has been a department-accredited verifier for two continuous years and has worked as a verifier in at least three completed verifications under the supervision of a department accredited lead verifier, with evidence of favorable assessment by the department for services performed; or,

(iii) evidence that the applicant has worked as a project manager or lead person for not less than four years, of which two may be graduate level work:

(‘a’) in the development of GHG or other air emissions inventories; or,

(‘b’) as a lead environmental data or financial auditor.

(3) Verifier Accreditation Application. To apply for accreditation as a verifier, the applicant shall submit the following documentation to the department:

(i) Evidence demonstrating the minimum education background required to act as a verifier for the department. Minimum education background means that the applicant has either:

(‘a’) a bachelors level college degree or equivalent in science, technology, business, statistics, mathematics, environmental policy, economics, or financial auditing; or

(‘b’) evidence demonstrating the completion of significant and relevant work experience or other personal development activities that have provided the applicant with the communication, technical, and analytical skills necessary to conduct verification.

(ii) Evidence demonstrating sufficient workplace experience to act as a verifier, including evidence that the applicant has a minimum of two years of full-time work experience in a professional role involved in emissions data management, emissions technology, emissions inventories, environmental auditing, or other technical skills necessary to conduct verification.

(4) The applicant must take a department-approved and administered general verification training consistent with the requirements of this Part and receive a passing score of greater than an unweighted 70 percent on an exit examination. If the applicant does not pass the exam after the training, they may retake the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the department-approved general verification training course.

(5) Sector-Specific Verifiers.

(i) Sector-Specific Verifier. The applicant seeking to be accredited as a sector-specific verifier as specified in section 4.2(a)(2) of this Part must, in addition to meeting the requirements for accredited lead verifier or verifier qualification, have at least two years of professional experience related to the sector in which they are seeking accreditation, take department sector-specific verification training and receive a passing score of greater than an unweighted 70 percent on an exit examination. If the applicant does not pass the exam after the training, they may take the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the department -approved sector-specific verification training. Applicants seeking sector-specific verifier accreditation as a process emissions specialist are exempt from the experience requirement.

(6) Nothing in this section shall be construed as preventing the department from requesting additional information or documentation from an applicant after receipt of the application for accreditation as a verification body, lead verifier, or verifier, or from seeking additional information from other persons or entities regarding the applicant’s fitness for qualification.

(d) Department Accreditation

(1) Within 90 days of receiving an application for accreditation as a verification body, lead verifier, verifier, or sector-specific verifier, the department shall inform the applicant in writing either that the application is complete or that additional specific information is required to make the application complete.

(2) Upon a finding by the department that an application for accreditation as a verification body, verifier, lead verifier, or sector-specific verifier is complete, meets all applicable regulatory requirements, and passes a performance review as defined pursuant to this Part, the prescreening requirement is met and the applicant will be eligible to attend the verification training required by this section.

(3) Within 45 days following completion of the application process and all applicable training and examination requirements, the department shall act to withhold or grant accreditation for the verification body, lead verifier, sector-specific verifier, or verifier.

(4) The decision for accreditation is valid for a period of three years, whereupon the applicant may re-apply for accreditation as a verifier, lead verifier, sector-specific verifier, or verification body if the applicant has not been subject to department enforcement action

under this Part. All department-approved general or sector-specific verification training and examination requirements applicable at the time of re-application must be met for accreditation to be renewed by the department. In addition, the performance review requirement set forth in paragraph (2) of this subdivision must be met for accreditation to be renewed by the department.

(5) All verification body requirements in paragraph (b)(1) of this section must be met for the department to renew the verification body accreditation.

(6) Within 20 days of being notified of any nonconformance in another voluntary or mandatory GHG program, a department-accredited verification body, lead verifier, sector-specific verifier, or verifier shall provide written notice to the department of the corrective action. That notification shall include reasons for the corrective action and the type of corrective action. The verification body or verifier must provide additional information to the department upon request.

(e) Modification, Suspension, or Revocation of a Decision Approving a Verification Body, Lead Verifier, or Verifier, and Voluntary Withdrawal from the Accreditation Program. The department may review and, for good cause, including any violation of Subpart 4 of this Part or any similar action in an analogous GHG system, modify, suspend, or revoke a decision providing accreditation to a verification body, lead verifier, or verifier.

(1) During suspension or revocation proceedings, the verification body, lead verifier, or verifier may not continue to provide verification services.

(2) Within 10 days of suspension or revocation of accreditation, a verification body must notify all emission sources or authorized project designees for whom it is providing

verification services or has provided verification services within the past six months of its suspension or revocation of accreditation.

(3) An emission source or authorized project designee who has been notified by a verification body of a suspended or revoked accreditation must contract with a different verification body for verification services.

(4) An accredited verification body or natural person verifier may request to voluntarily withdraw its or their accreditation by providing a written notice to the department requesting such withdrawal.

(f) Subcontracting. The following requirements shall apply to any verification body that elects to subcontract a portion of verification services.

(1) All subcontractors must be accredited by the department to perform the verification services for which the subcontractor has been engaged by the verification body.

(2) The verification body must assume full responsibility for verification services performed by subcontractor verifiers.

(3) A verification body shall not use subcontractors to meet the minimum staff total or lead verifier requirements as specified in clauses (b)(1)(i)('a') and (b)(1)(i)('b') of this section.

(4) A verifier acting as a subcontractor to another verification body shall not further subcontract or outsource verification services for a reporting entity.

(5) A verification body that engages a subcontractor shall be responsible for demonstrating an acceptable level of conflict-of-interest, as provided in section 4.4 of this Part, between its subcontractor and the emission source for which it will provide verification

services.

(6) A verification body may not use a subcontractor as the independent reviewer.

253-4.4 Conflict-of-Interest Requirements for Verification Bodies

(a) Conflict-of-Interest Requirements. The conflict-of-interest provisions of this section shall apply to verification bodies, lead verifiers, and verifiers accredited by the department to perform verification services for emission sources. Any natural person or company that is hired by an emission source to contract with a verification body on behalf of the emission source is subject to the conflict-of-interest assessment in this Part. In such instances, the verification body must assess the potential conflict-of-interest between itself and the contracting person as well as between itself and the emission source and must also address the potential conflict-of-interest between the contracting person and the emission source, including a written assessment provided and signed by the contracting person.

(b) High Potential for Conflict-of-Interest. The potential for a conflict-of-interest must be deemed to be high where:

(1) the verification body and emission source share any management staff or board of directors membership, or any of the senior management staff of the emission source have been employed by the verification body, or vice versa, within the previous five years; or

(2) any employee of the verification body, or any employee of a related person, or a subcontractor who is a member of the verification team has provided to the emission source any of the following services within the previous five years:

(i) designing, developing, implementing, reviewing, or maintaining an inventory or information or data management system for facility air emissions, or, where applicable, electricity or fuel transactions, unless the review was part of providing GHG verification services;

(ii) developing GHG emission factors or other GHG-related engineering analysis, including developing or reviewing New York State Environmental Quality Review or SEQR, City of New York Environmental Quality Review or CEQR, National Environmental Policy Act or NEPA, or New York State Climate Act section 7(2) GHG analyses that include facility specific information;

(iii) designing energy efficiency, renewable power, or other projects that explicitly identify GHG reductions as a benefit;

(iv) designing, developing, implementing, conducting an internal audit, consulting, or maintaining a GHG emission reduction;

(v) owning, buying, selling, trading, or retiring shares, or stocks that was developed by or resulting reduction credits are owned by the emission source;

(vi) dealing in or being a promoter of credits on behalf of an authorized project designee where the credits are owned by the emission source;

(vii) preparing or producing GHG related manuals, handbooks, or procedures specifically for the emission source;

(viii) appraisal services of carbon or GHG liabilities or assets;

(ix) brokering in, advising on, or assisting in any way in carbon or GHG-related markets;

(x) directly managing any health, environment or safety functions for the emission source;

(xi) bookkeeping or other services related to accounting records or financial statements;

(xii) any service related to development of information systems, including consulting on the development of environmental management systems, such as those conforming to ISO 14001:2015 Environmental management systems — Requirements with guidance for use Published (Edition 3, 2015) (see Table 1, section 200.9 of this Title) or energy management systems such as those conforming to ISO 50001:2018 Energy management systems —Requirements with guidance for use Published (Edition 2, 2018) (see Table 1, section 200.9 of this Title), unless those systems will not be part of the verification process;

(xiii) appraisal and valuation services, both tangible and intangible;

(xiv) fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the resulting services will not be part of the verification process;

(xv) any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;

(xvi) any internal audit service that has been outsourced by the emission source that relates to the emission source's internal accounting controls, financial systems or financial statements, unless the result of those services will not be part of the verification process;

(xvii) acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the emission source;

(xviii) any legal services;

(xix) expert services to the reporting entity, a trade or membership group to which the reporting entity belongs, or a legal representative for the purpose of advocating the emission source's interests in litigation or in a regulatory or administrative proceeding or investigation.

(xx) verification services that are not conducted in accordance with, or equivalent to, section 4.4 of this Part requirements, unless the systems and data reviewed during those services, as well as the result of those services, will not be part of the verification process.

(xxi) Member for the purposes of this section means any employee or subcontractor of the verification body or related entities of the verification body. Member also includes any natural person with majority equity share in the verification body or its related entities. Related entity for the purposes of this section means any direct parent company, direct subsidiary, or sister company.

(3) The potential for conflict-of-interest shall be deemed to be high when any staff member of the verification body provides any type of non-monetary incentive to an emission source to secure a verification services contract.

(4) The potential for a conflict-of-interest shall also be deemed to be high where any staff member of the verification body has provided verification services for the emission source except within the time periods in which the reporting entity is allowed to use the same

verification body as specified in section 4.1(a) of this Part.

(c) Low Potential for Conflict-of-Interest. The potential for a conflict-of-interest shall be deemed to be low where the following conditions are met:

(1) no potential for a high conflict-of-interest is found pursuant to subdivision (b) of this section; and

(2) any services provided by any member of the verification body or verification team to the emission source, within the last five years, are valued at less than 20 percent of the fee for the proposed verification services. Any verification conducted in accordance with, or equivalent to, section 4.4 of this Part provided by the verification body or verification team outside the jurisdiction of the department is excluded from this financial assessment but must be disclosed to the department in accordance with subdivision (e) of this section.

(3) Non-department verification services are deemed to be low risk if those services are conducted in accordance with, or equivalent to, section 4.4 of this Part, including, but not limited to, third-party certification of environmental management system under ISO 14001:2015 Environmental management systems — Requirements with guidance for use Published (Edition 3, 2015) (see Table 1, section 200.9 of this Title) or energy management system under ISO 50001:2018 Energy management systems — Requirements with guidance for use Published (Edition 2, 2018) (see Table 1, section 200.9 of this Title).

(d) Medium Potential for Conflict-of-Interest. The potential for a conflict-of-interest shall be deemed to be medium where the potential for a conflict-of-interest is not deemed to be either high or low as specified in subdivisions (b) and (c) of this section. The potential for conflict-of-interest will also be deemed to be medium where there are any instances of personal or familial relationships between the members of the verification body and management or staff of the emission source and when a conflict-of-interest self-evaluation is submitted pursuant to subdivision (h) of this section.

(1) If a verification body identifies a medium potential for conflict-of-interest and intends to provide verification services for the reporting entity, the verification body shall submit, in addition to the submittal requirements specified in subdivision (e) of this section, a plan to avoid, neutralize, or mitigate the potential conflict-of-interest situation. At a minimum, the conflict-of-interest mitigation plan shall include:

(i) A demonstration that any natural persons with potential conflicts have been removed and insulated from the project.

(ii) An explanation of any changes to the organizational structure or verification body to remove the potential conflict-of-interest. A demonstration that any unit with potential conflicts has been divested or moved into an independent person or any subcontractor with potential conflicts has been removed.

(iii) Any other circumstance that specifically addresses other sources for potential conflict-of-interest.

(2) As provided in paragraph (f)(4) of this section, the department shall evaluate the conflict-of-interest mitigation plan and determine whether verification services may proceed.

(e) Conflict-of-Interest Submittal Requirements for Accredited Verification Bodies.

(1) Before the start of any work related to providing verification services to an emission source, a verification body must first be authorized in writing by the department to

provide verification services. To obtain authorization the verification body shall submit to the department a self-evaluation of the potential for any conflict-of-interest that the verification body, related entities, or any subcontractors performing verification services may have with the emission source for which it will perform verification services. The submittal shall include the following:

(i) identification of whether the potential for conflict-of-interest is high, low, or medium based on factors specified in subdivisions (b), (c), and (d) of this section;

(ii) identification of whether the verification body, related person, or any member of the verification team has previously provided verification services for the emission source or related entities and, if so, provide a description of such services and the years in which such services were provided;

(iii) identification of whether any member of the verification team, verification body, or related person has engaged in services of any nature, other than department verification services, with the emission source or related entities either within or outside New York during the previous five years. If services other than the department verification services have previously been provided, the following information shall also be submitted:

('a') identification of the nature and location of the work performed for the emission source or related person and whether the work is similar to the type of work to be performed during verification, such as emissions inventory, auditing, energy efficiency, renewable energy, or other work with implications for the emission source's GHG emissions pursuant to this Part;

('b') the nature of past, present or future relationships of any member of the verification team, verification body, or related entities with the emission source or related entities including:

('1') instances when any member of the verification team, verification body, or related entities has performed or intends to perform work for the emission source or related entities;

('2') identification of whether work is currently being performed for the emission source or related entities, and if so, the nature of the work;

('3') how much work was performed for the emission source or related entities in the last five years, in dollars;

('4') whether any member of the verification team, verification body, or related entities has contracts or other arrangements to perform work for the emission source or a related person;

('5') how much work related to greenhouse gases the verification team has performed for the emission source or related entities in the last five years, in dollars;

('c') explanation of how the amount and nature of work previously performed is such that any member of the verification team's credibility and lack of bias should not be under question;

(iv) a list of names of the staff that would perform verification services for the emission source, and a description of any instances of personal or family relationships with management or employees of the emission source that potentially represent a conflict-of-interest; and,

(v) identification of any other circumstances known to the verification body, or emission source that could result in a conflict-of-interest; and

(vi) attest, in writing, to the department as follows:

"I certify under penalty of the laws of the State of New York the information provided in the Conflict-of-Interest submittal is true, accurate, and complete."

(f) Conflict-of-Interest Determinations. The department must review the self-evaluation submitted by the verification body and determine whether the verification body is authorized to perform verification services for the reporting entity.

(1) The department shall notify the verification body in writing when the conflict-of-interest evaluation information submitted under subdivision (e) of this section is deemed complete. Within 20 days of deeming the information complete, the department shall determine whether the verification body is authorized to proceed with verification and must so notify the verification body.

(2) If the department determines the verification body or any member of the verification team meets the criteria specified in subdivision (b) of this section, the department shall find a high potential conflict-of-interest and verification services may not proceed.

(3) If the department determines that there is a low potential conflict-of-interest, verification services may proceed.

(4) If the department determines that the verification body and verification team have a medium potential for a conflict-of-interest, the department shall evaluate the conflict-of-interest mitigation plan submitted pursuant to subdivision (d) of this section and may

request additional information from the applicant to complete the determination. In determining whether verification services may proceed, the department may consider factors including, but not limited to, the nature of previous work performed, the current and past relationships between the verification body, related persons, and its subcontractors with the emission source and related persons, and the cost of the verification services to be performed. If the department determines that these factors when considered in combination demonstrate an acceptable level of potential conflict-of-interest, the department will authorize the verification body to provide verification services.

(g) Monitoring Conflict-of-Interest Situations.

(1) After commencement of verification services, the verification body shall monitor and immediately make full disclosure in writing to the department regarding any potential for a conflict-of-interest situation that arises. This disclosure shall include a description of actions that the verification body has taken or proposes to take to avoid, neutralize, or mitigate the potential for a conflict-of-interest.

(2) The verification body shall continue to monitor arrangements or relationships that may be present for a period of one year after the completion of verification services. During that period, within 30 days of the verification body or any verification team member entering into any contract with the emission source or related person for which the body has provided verification services, the verification body shall notify the department of the contract and the nature of the work to be performed, and revenue received. The department, within 30 days, will determine the level of conflict using the criteria in subdivisions (a) through (d) of this section, if the emission source must reverify its emissions

data report, and if accreditation revocation is warranted.

(3) The verification body shall notify the department within 30 days of any emerging conflicts of interest during the time verification services are being provided.

(i) If the department determines that a disclosed emerging potential conflict is medium risk and this risk can be mitigated, the verification body is deemed to have met the conflict-of-interest requirements to continue to provide verification services to the emission source and will not be subject to suspension or revocation of accreditation as specified in section 4.3(e) of this Part.

(ii) If the department determines that a disclosed emerging potential conflict is medium or high risk and this risk cannot be mitigated, the verification body will not be able to continue to provide verification services to the emission source and may be subject to suspension or revocation of accreditation under section 4.3(e) of this Part.

(4) The verification body shall report to the department any changes in its organizational structure, including mergers, acquisitions, or divestitures, for one year after completion of verification services.

(5) The department may invalidate a verification finding if a potential conflict-of-interest has arisen for any member of the verification team. In such a case, the emission source shall be provided 90 days to complete reverification.

(6) If the verification body or its subcontractor(s) are found to have violated the conflict-of-interest requirements of this Part, the department may rescind accreditation of the body, its verifier staff, or its subcontractor(s) as provided in section 4.2(d) of this Part.