6 NYCRR Part 203, Oil and Natural Gas Sector

6 NYCRR Part 200, General Provisions

Express Terms Summary

This proposal applies to owners and operators of equipment and components that are associated with sources in the following oil and natural gas sectors:

(1) Oil and natural gas production

(2) Oil, condensate and produced water separation and storage

(3) Natural gas storage

(4) Natural gas gathering and boosting

(5) Natural gas transmission and compressor stations

(6) Natural gas metering and regulating stations

Measurements, abbreviations and acronyms are listed.

Definitions specific to this rule are listed.

For wells, gathering lines, transmission lines and compressor stations, storage vessels with a potential to emit greater than or equal to six (6) tons per year (tpy) of volatile organic compounds (VOC) must meet the following requirements:

(1) Storage vessels installed prior to January 1, 2023 must have a vapor control efficiency of ninety-five (95) percent.

(2) Storage vessels installed on or after January 1, 2023 must not vent to the atmosphere.

For wells, gathering lines, transmission lines and compressor stations, Natural Gas actuated Pneumatic Devices and Pumps have the following requirements:

(1) Beginning January 1, 2023, continuous bleed natural gas pneumatic devices shall not vent natural gas to the atmosphere with few exceptions which are outlined in the full regulation.

(2) Intermittent bleed natural gas actuated pneumatic devices: Beginning January 1, 2023, intermittent bleed natural gas actuated pneumatic devices shall comply with the leak detection and repair (LDAR) requirements.

(3) Natural gas actuated pneumatic pumps: Beginning January 1, 2023, natural gas actuated pneumatic pumps shall not vent natural gas to the atmosphere and shall comply with the LDAR requirements.

Centrifugal Compressors have the following requirements (compressors that operate greater than 200 hours over a rolling twelve (12) month period):

(1) Beginning January 1, 2023, centrifugal compressors with wet seals shall control the wet seal vent gas with the use of a vapor collection system as described in Subpart 203-8 or replaced with a dry seal.

(2) Beginning January 1, 2023, components on driver engines and compressors that use a wet seal or a dry seal shall comply with the LDAR requirements specified in Subpart 203-7, and;

(3) The compressor wet seal shall be measured annually by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument) while the compressor is running at normal operating temperature in order to determine the wet seal emission flow rate using defined methods.

(4) A compressor with a wet seal emission flow rate greater than three (3) standard cubic feet per minute (scfm), or a combined flow rate greater than the number of wet seals multiplied by

three (3) scfm, shall be successfully repaired within thirty (30) days of the initial flow rate measurement.

(5) If parts are not available to make the repairs, the wet seal shall be replaced with a dry seal no later than eighteen (18) months after the exceeding measurement is made.

Reciprocating Compressors have the following requirements (compressors that operate greater than 200 hours over a rolling twelve (12) month period):

(1) Beginning January 1, 2023, components on driver engines and compressors shall comply with the LDAR requirements specified in Subpart 203-7 with potential exceptions.

(2) The compressor rod packing or seal emission flow rate through the rod packing or seal vent stack shall be measured annually by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument) while the compressor is running at normal operating temperature using defined methods.

(3) Beginning January 1, 2023, compressor vent stacks used to vent rod packing or seal emissions shall be controlled with the use of a vapor collection system as specified; or,

(4) A compressor with a rod packing or seal with a measured emission flow rate greater than two (2) scfm, or a combined rod packing or seal emission flow rate greater than the number of compression cylinders multiplied by two (2) scfm, shall be successfully repaired within 30 days from the date of the initial emission flow rate measurement.

(a) An extension to the thirty (30) day deadline may be granted by the Department if the owner or operator can demonstrate that the parts or equipment required to make necessary repairs have been ordered and the owner or operator notifies the Department as specified in Section 203-10.3 to report the delay and provides an estimated time by which the repairs will be completed.

(5) A reciprocating natural gas compressor with a rod packing or seal emission flow rate measured above the standard specified as a critical component, shall be successfully repaired by the end of the next scheduled process shutdown or within twelve (12) months from the date of the initial flow rate measurement, whichever is sooner.

Blowdown activity at compressor stations and transmission pipelines greater than ten thousand (10,000) feet cubed (ft^3) have the following requirements:

(1) Planned blowdowns

(i) Provide notification to the Department and appropriate local authorities forty-eight (48) hours in advance of a blowdown event, the notification shall include, but not be limited to, the following information:

('a') Location

('b') Date

('c') Time and duration

('d') Contact person

('e') Reason for blowdown

('f') Estimated volume of release

(ii) If any of the information reported prior to the blowdown changed during or after the blowdown, another notification to the Department and appropriate local authorities shall be made with the updates no later than forty-eight (48) hours after the end of the blowdown.

(2) Unplanned blowdowns

(i) Provide notification to the Department and appropriate local authorities within thirty (30) minutes of blowdown or as soon as it is safe to do so. The notification shall include, but not be limited to, the following information:

('a') Location

('b') Date

('c') Time and duration

('d') Contact person

('e') Reason for blowdown

('f') Estimated volume of release

Pigging activity along natural gas pipelines are required to:

(1) Record and report pigging activities and estimated natural gas loss and report to the Department by March 31st of each year for the previous calendar year. The report shall include, but not be limited to:

(i) Date of each activity

(ii) Estimated volume of release for each activity

Natural Gas Storage Monitoring Requirements

(1) Applicability: The requirements of this section apply to natural gas underground storage facilities.

(2) Natural gas underground storage facility sources are subject to the LDAR requirements as specified in Subpart 203-7.

City Gate Metering and Regulating

(a) Applicability: The requirements of this section apply to all metering and regulating components at the City Gate.

(b) Metering and regulating components are subject to the LDAR requirements in Subpart 203-7.

Provisions for Feasibility and Safety

(a) A repair or replacement may not be delayed unless it results in the following:

(1) a vented blowdown,

(2) a gathering and boosting station shutdown,

(3) a well shutdown,

(4) a well shut-in,

(5) is deemed technically infeasible or unsafe by the New York State Department of Public Service or other federal or state regulatory agency.

(b) The repair or replacement delay may be extended until the earliest event listed below.

(1) the next compressor station shutdown,

(2) the next gathering and boosting station shutdown,

(3) well shutdown,

(4) well shut-in,

(5) the next unscheduled, planned or emergency vent blowdown, or

(6) within one (1) year.

Reporting and Recordkeeping

(1) Baseline Report

(a) Applicability: All sources as described in Section 203-1.1.

(b) Owners or operators of components or processes subject to this Subpart must submit a report to the Department by March 31, 2023 or by March 31st the year following initiation of operation.

(c) The report shall be in a format approved by the Department and shall include, but not be limited to, information on the following:

(1) separators

(2) storage vessels

(3) compressors

(4) gas drying systems

(5) pneumatic devices

(6) metering and regulating systems

(2) Recordkeeping

(a) Reciprocating Natural Gas Compressors

(1) Maintain, for at least five (5) years from the date of each leak concentration measurement, a record of each rod packing leak concentration measurement found above the minimum leak threshold as defined in Section 203-4.4.

(2) Maintain, for at least five (5) years from the date of each emissions flow rate measurement, a record of each rod packing emission flow rate measurement.

(3) Maintain, for at least five (5) years a record that documents the date(s) and hours of operation a compressor is operated in order to demonstrate compliance with the rod packing leak concentration or emission flow rate measurement in the event that the compressor is not operating during a scheduled inspection.

(4) Maintain records that provide proof that parts or equipment required to make necessary repairs have been ordered.

(b) Centrifugal Natural Gas Compressors

(1) Maintain, for at least five (5) years from the date of each emissions flow rate measurement, a record of each wet seal emission flow rate measurement.

(2) Maintain, for at least five (5) years, a record that documents the date(s) and hours of operation a compressor is operated in order to demonstrate compliance with the wet seal emission flow rate measurement in the event that the compressor is not operating during a scheduled inspection.

(3) Maintain records that provide proof that parts or equipment required to make necessary repairs have been ordered.

(c) Natural Gas Actuated Pneumatic Devices

(1) Maintain, for at least five (5) years from the date of each emissions flow rate measurement, a record of the emission flow rate measurement

(d) Leak Detection and Repair

(1) Maintain, for at least five (5) years from each inspection, a record of each leak detection and repair inspection.

(2) Maintain, for at least five (5) years from the date of each inspection, component leak and repair documentation.

(3) Maintain records for at least five (5) years that provide proof that parts or equipment required to make necessary repairs have been ordered.

(4) Maintain gas service utility records for at least five (5) years that demonstrate that a system has been temporarily classified as critical to reliable public gas operation throughout the duration of the classification period.

(e) Vapor Collection System and Vapor Control Devices

(1) Maintain records for at least five (5) years that provide proof that parts or equipment required to make necessary repairs have been ordered and installed.

(3) Reporting submissions and retention

(a) Reports shall be delivered to both the:

(1) Bureau Director, Bureau of Air Quality Planning, Division of Air Resources, 625 Broadway, Albany NY 12233, and

(2) The Regional Air Pollution Control Engineer in the corresponding Department Region to the source.

(b) Source owners and operators must maintain reports for at least five (5) years and make them available to the Department upon request.

The Part 200 additions will incorporate by reference EPA Method 21, Volatile Organic Compound Leaks, found in Title 40 Code of Federal Regulations (CFR) Part 60, appendix A-7.

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.

6 NYCRR Part 203, Oil and Natural Gas Sector

Express Terms

203-1 Emissions from Oil and Natural Gas Activities General Provisions

203-1.1 General Applicability

(a) This Part applies to owners and operators of equipment and components that are associated with sources in the following oil and natural gas sectors:

(1) Oil and natural gas production

(2) Oil, condensate and produced water separation and storage

(3) Natural gas storage

(4) Natural gas gathering and boosting

(5) Natural gas transmission and compressor stations

(6) Natural gas metering and regulating stations

(b) This Part does not apply to distributing gas utilities or to equipment and components located downstream of a city gate.

203-1.2 Measurements, abbreviations and acronyms

(a) ASME: American Society of Mechanical Engineers

(b) CH_4: Methane

(c) FID: Flame Ionization Detector

(d) LDAR: Leak Detection and Repair

(e) OGI: Optical Gas Imaging

(f) PTE: Potential to Emit

(g) psig: pounds per square inch, gauge

(h) scfh: standard cubic feet per hour

(i) scfm: standard cubic feet per minute

(j) tpy: tons per year

(k) VOC: volatile organic compound

203-1.3 Definitions

(a) For the purpose of this Part, the general definitions of Parts 200 and 201 of this Title apply unless they are inconsistent with subdivision 203-1.3(b).

(b) For the purpose of this Part, the following definitions also apply:

(1) “Centrifugal compressor” means equipment that increases the pressure of natural gas by centrifugal action through an impeller.

(2) “Centrifugal compressor seal” means a wet or dry seal around the compressor shaft where the shaft exits the compressor case.

(3) “City gate” means a point or measuring where custody transfer occurs between a natural gas transmission system pipeline company/operator and a distribution system company/operator.

(4) “Component” is meant to include but is not limited to; a valve, fitting, flange, threaded-connection, process drain, stuffing box, pressure-vacuum valve, pressure-relief device, pipes, seal fluid system, diaphragm, hatch, sight-glass, meter, open-ended line, well casing, natural gas actuated pneumatic device, natural gas actuated pneumatic pump, or reciprocating compressor rod packing or compressor seals.

(5) “Condensate” means liquid hydrocarbons that were originally in the gaseous phase in the reservoir and liquids recovered by surface separation from natural gas.

(6) "Continuous bleed" means the continuous venting of natural gas from a gas actuated pneumatic device to the atmosphere by design.

(7) “Critical component” means any component that would require the shutdown of a critical process unit if that component was shutdown or disabled.

(8) "Critical process unit" means a process unit or group of components at such unit that must remain in service because of their importance to the overall process. A critical process unit is required to continue to operate, has no equivalent equipment to replace it, cannot be bypassed, and for which it is technically infeasible to repair leaks from that process unit without shutting it down and opening the process unit to the atmosphere.

(9) “Emulsion” means any mixture of crude oil, condensate, or produced water with varying quantities of natural gas entrained in the liquids.

(10) “Equipment” means any stationary or portable machinery, object, or contrivance covered by this Part.

(11) “Fuel gas” means gas generated at a petroleum refinery or petrochemical plant and that is combusted separately or in any combination with any type of gas.

(12) “Fuel gas system” means any system that supplies natural gas as a fuel source to on-site natural gas actuated equipment other than a vapor control device.

(13) “Hoop stress” means the stress in a pipe wall, acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe and produced by the pressure of the fluid in the pipe.

(14) "Intermittent bleed" means the intermittent venting of natural gas from a gas actuated pneumatic device to the atmosphere by design.

(15) “Leak or fugitive leak” means the unintentional release of emissions at a rate greater than or equal to the leak thresholds specified in this Part.

(16) “Leak detection and repair” or “LDAR” means the inspection of components to detect leaks of VOC and CH_4 and the repair of those components with leak rates above the standards and within the timeframes specified in this Part.

(17) “Metering Station” means a station designed for the continuous measurement of the quantity of natural gas being transported in a pipeline and may include simultaneous analysis of natural gas quality.

(18) “Natural gas” means 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.

(19) "Natural gas gathering and boosting station" means all equipment and components associated with moving natural gas to a natural gas processing plant, or transmission pipeline, or distribution pipeline.

(20) “Natural gas transmission compressor station” means all equipment and components located within a facility fence line associated with moving natural gas from production fields or natural gas processing plants through natural gas transmission pipelines, or within natural gas underground storage fields.

(21) "Natural gas transmission pipeline" means a pipeline, other than a gathering line, that:

(i) transports gas from a gathering line or storage facility to a distribution center or storage facility, or directly to a large volume user that is not downstream from a distribution center; or

(ii) operates at a hoop stress of twenty (20) percent or more of specific minimum yield strength; or

(iii) transports gas within a storage field.

(22) “Natural gas underground storage” or “Reservoir” means all equipment and components, including the surface components of underground storage wells, associated with the temporary subsurface storage of natural gas in any underground reservoir, natural or artificial cavern or geologic dome, sand or stratigraphic trap, whether or not previously occupied by or containing oil or natural gas.

(23) “Non-associated gas” means natural gas that is not produced as a byproduct of crude oil production and may or may not be produced with condensate.

(24) “Oil” means 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.

(25) “Optical gas imaging or OGI” means using an instrument, such as a thermal infrared camera, that makes emissions visible that may otherwise be invisible to the naked eye.

(26) “Pigging” means using devices or instruments known as 'pigs' to perform various cleaning, clearing, maintenance, inspection, dimensioning, process and pipeline testing operations on new and existing pipelines.

(27) “Pneumatic device” means an automation device that uses natural gas or compressed air to control a process.

(28) “Pneumatic pump” means a device that uses natural gas or compressed air to power a piston or diaphragm in order to circulate or pump liquids.

(29) "Portable pressurized separator" means a pressure vessel, that can be moved from one location to another without having to be dismantled, and is capable of separating and storing crude oil, condensate, or produced water at the temperature and pressure of the separator required for sampling.

(30) "Portable tank" means a tank that can be moved from one location to another without having to be dismantled.

(31) "Pressure vessel" means any hollow container used to hold gas or liquid and rated, as indicated by an ASME pressure rating stamp, and operated to contain normal working pressures of at least 15 pounds per square inch, gauge (psig) without continuous vapor loss to the atmosphere.

(32) “Production” means all activities associated with the production or recovery of emulsion, crude oil, condensate, produced water, or natural gas at facilities to which this Part applies.

(33) “Produced water” means water recovered from an underground reservoir as a result of crude oil, condensate, or natural gas production that may be recycled, disposed, or re-injected into an underground reservoir.

(34) “Reciprocating natural gas compressor” means 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.

(35) “Reciprocating natural gas compressor rod packing” means 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.

(36) “Reciprocating natural gas compressor seal” means any device or mechanism used to limit the amount of natural gas that vents from a compression cylinder into the atmosphere.

(37) “Regulating Station” means a station that is placed along a pipeline to reduce the pressure of the gas to the appropriate operating pressure for each system.

(38) “Sales Gas” means the raw natural gas, after processing to remove liquid petroleum gas, condensate and carbon dioxide. Sales Gas usually consists mainly of CH_4 and ethane.

(39) “Separator” means a tank used to physically separate the oil, gas, and water produced simultaneously from a well.

(40) "Separator and tank system" means the first separator in a crude oil or natural gas production system and any tank or sump connected directly to the first separator.

(41) “Storage Vessel” 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.

(42) "Successful repair" means tightening, adjusting, or replacing equipment or a component for the purpose of stopping or reducing fugitive leaks below the minimum leak detection threshold or emission flow rate standard specified in this Part.

(43) “Total Hydrocarbon” means organic compounds of hydrogen and carbon whose densities, boiling points, and freezing points increase as their molecular weights increase. Although composed of only two elements, hydrocarbons exist in a variety of compounds, because of the strong affinity of the carbon atom for other atoms and for itself.

(44) “Vapor collection system” means equipment and components installed on compressors, pressure vessels, separators, tanks, or sumps including piping, connections, and flow-inducing devices used to collect and route emission vapors to a processing, sales gas, or fuel gas system, or to a vapor control device.

(45) “Vapor control device” means equipment used to reduce hydrocarbon emissions.

(46) “Vapor control efficiency” means the ability of a vapor control device to reduce emissions, expressed as a percentage, that can be estimated by calculation or by measuring the total hydrocarbon concentration or mass flow rate at the inlet and outlet of the vapor control device.

(47) “Vent or venting” means the intentional or automatic release of natural gas into the atmosphere from components, equipment, or activities described in this Part.

(48) ”Well” means 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.

(49) "Well Site" means the well pad and access roads, equipment storage and staging areas, vehicle turnarounds, and any other areas directly or indirectly impacted by activities involving a well.

203-2 Oil and Natural Gas Well Activities

203-2.1 Storage Vessels

(a) Applicability: The requirements of this section apply to all storage vessels located at oil and natural gas well sites with a PTE greater than or equal to six (6) tpy of VOC.

(b) Control requirements.

(1) Storage vessels installed prior to January 1, 2023 must have a vapor control efficiency of ninety-five (95) percent.

(2) Storage vessels installed on or after January 1, 2023 must not vent to the atmosphere.

203-2.2   Natural Gas Actuated Pneumatic Devices and Pumps

(a) Applicability: The requirements of this section apply to natural gas actuated pneumatic devices and pumps located at oil and natural gas well sites.

(b) Continuous bleed natural gas pneumatic devices:

(1) Beginning January 1, 2023, continuous bleed natural gas pneumatic devices shall not vent natural gas to the atmosphere except as described in 203-2.2(b)(2)(i) and shall comply with 203-2.2(b)(2)(ii)-(v) and the LDAR requirements specified in Subpart 203-7.

(2) Continuous bleed natural gas actuated pneumatic devices installed prior to January 1, 2023 may be used provided they meet all of the following requirements as of January 1, 2023:

(i) No device shall vent natural gas at a rate greater than six (6) standard cubic feet per hour (scfh) when the device is idle and not actuating.

(ii) All devices must be clearly marked with a permanent tag that identifies the vented emissions rate as less than or equal to six (6) scfh.

(iii) All devices must be tested by January 1, 2024 and then tested annually, no later than thirteen (13) months and no earlier than eleven (11) months from the previous test using a direct measurement method (high volume sampling, bagging, calibrated flow measuring instrument); and,

(iv) Any device with a measured emissions flow rate greater than six (6) scfh shall be successfully repaired within fourteen (14) days from the date of the initial emission flow rate measurement.

(v) The owner or operator shall maintain a record of the flow rate measurement and shall report the result to the Department within sixty (60) days after completed.

(c) Continuous bleed natural gas actuated pneumatic devices and pumps that need to be replaced or retrofitted to comply with the requirements specified shall do so by either:

(1) Collecting all vented natural gas using a vapor collection system as specified in Subpart 203-8; or,

(2) By using compressed air or electricity in lieu of natural gas to operate.

(d) Intermittent bleed natural gas actuated pneumatic devices: Beginning January 1, 2023, intermittent bleed natural gas actuated pneumatic devices shall comply with the LDAR requirements specified in Subpart 203-7 when the device is idle and not controlling.

(e) Natural gas actuated pneumatic pumps: Beginning January 1, 2023, natural gas actuated pneumatic pumps shall not vent natural gas to the atmosphere and shall comply with the LDAR requirements specified in Subpart 203-7.

203-2.3 Metering and Regulating

(a) Metering and regulating components are subject to the LDAR requirements in Subpart 203-7.

203-3 Natural Gas Gathering Lines

203-3.1 Storage Vessels

(a) Applicability: The requirements of this section apply to all storage vessels located at oil and natural gas well sites with a PTE greater than or equal to six (6) tpy of VOC.

(b) Control requirements

(1) Storage vessels installed prior to January 1, 2023 must have a vapor control efficiency of ninety-five (95) percent.

(2) Storage vessels installed on or after January 1, 2023 must not vent to the atmosphere.

203-3.2 Natural Gas actuated Pneumatic Devices and Pumps

(a) Applicability: The requirements of this section apply to all natural gas actuated pneumatic devices and pumps located at gathering and boosting locations.

(b) Continuous bleed natural gas pneumatic devices:

(1) Beginning January 1, 2023, continuous bleed natural gas pneumatic devices shall not vent natural gas to the atmosphere except as described in 203-2.2(b)(2)(i) and shall comply with 203-3.2(b)(2)(ii)-(v) and the LDAR requirements specified in Subpart 203-7.

(2) Continuous bleed natural gas actuated pneumatic devices installed prior to January 1, 2023 may be used provided they meet all of the following requirements:

(i) No device shall vent natural gas at a rate greater than six (6) standard cubic feet per hour (scfh) when the device is idle and not actuating.

(ii) All devices must be clearly marked with a permanent tag that identifies the vented emissions rate as less than or equal to six (6) scfh.

(iii) All devices must be tested by January 1, 2024 and then tested annually, no later than thirteen (13) months and no earlier than eleven (11) months from the previous test using a direct measurement method (high volume sampling, bagging, calibrated flow measuring instrument); and,

(iv) Any device with a measured emissions flow rate greater than six (6) scfh shall be successfully repaired within fourteen (14) days from the date of the initial emission flow rate measurement.

(v) The owner or operator shall maintain a record of the flow rate measurement and shall report the result to the Department within sixty (60) days after completed.

(c) Continuous bleed natural gas actuated pneumatic devices and pumps which need to be replaced or retrofitted to comply with the requirements specified shall do so by either:

(1) Collecting all vented natural gas with the use of a vapor collection system as specified in Subpart 203-8; or,

(2) By using compressed air or electricity in lieu of natural gas to operate.

(d) Intermittent bleed natural gas actuated pneumatic devices: Beginning January 1, 2023, intermittent bleed natural gas actuated pneumatic devices shall comply with the LDAR requirements specified in Subpart 203-7 when the device is idle and not controlling.

(e) Natural gas actuated pneumatic pumps: Beginning January 1, 2023, natural gas actuated pneumatic pumps shall not vent natural gas to the atmosphere and shall comply with the LDAR requirements specified in Subpart 203-7.

203-3.3 Metering and Regulating

(a) Metering and regulating components are subject to LDAR requirements in Subpart 203-7.

203-4 Natural Gas Transmission Pipelines and Compressor Stations

203-4.1 Storage Vessels

(a) Applicability: The requirements of this section apply to all storage vessels located at oil and natural gas well sites with a PTE greater than or equal to six (6) tpy of VOC.

(b) Control requirements.

(1) Storage vessels installed prior to January 1, 2023 must have a vapor control efficiency of ninety-five (95) percent.

(2) Storage vessels installed on or after January 1, 2023 must not vent to the atmosphere.

203-4.2 Natural Gas actuated Pneumatic Devices and Pumps

(a) Applicability: The requirements of this section apply to natural gas actuated pneumatic devices and pumps located at compressor stations.

(b) Continuous bleed natural gas pneumatic devices:

(1) Beginning January 1, 2023, continuous bleed natural gas pneumatic devices shall not vent natural gas to the atmosphere except as described in 203-2.2(b)(2)(i) and shall comply with 203-4.2(b)(2)(ii)-(v) and the LDAR requirements specified in Subpart 203-7.

(2) Continuous bleed natural gas actuated pneumatic devices installed prior to January 1, 2023 may be used provided they meet all of the following requirements as of January 1, 2023:

(i) No device shall vent natural gas at a rate greater than six (6) standard cubic feet per hour (scfh) when the device is idle and not actuating.

(ii) All devices must be clearly marked with a permanent tag that identifies the natural gas flow rate as less than or equal to six (6) scfh.

(iii) All devices must be tested by January 1, 2024 and then tested annually, no later than thirteen (13) months and no earlier than eleven (11) months from the previous test using a direct measurement method (high volume sampling, bagging, calibrated flow measuring instrument); and,

(iv) Any device with a measured emissions flow rate greater than six (6) scfh shall be successfully repaired within fourteen (14) days from the date of the initial emission flow rate measurement.

(v) The owner or operator shall maintain a record of the flow rate measurement and shall report the result to the Department within sixty (60) days after completed.

(c) Continuous bleed natural gas actuated pneumatic devices and pumps which need to be replaced or retrofitted to comply with the requirements specified shall do so by either:

(1) Collecting all vented natural gas with the use of a vapor collection system as specified in Subpart 203-8; or,

(2) By using compressed air or electricity in lieu of natural gas to operate.

(d) Intermittent bleed natural gas actuated pneumatic devices: Beginning January 1, 2023, intermittent bleed natural gas actuated pneumatic devices shall comply with the LDAR requirements specified in Subpart 203-7 when the device is idle and not controlling.

(e) Natural gas actuated pneumatic pumps: Beginning January 1, 2023, natural gas actuated pneumatic pumps shall not vent natural gas to the atmosphere and shall comply with the LDAR requirements specified in Subpart 203-7.

203-4.3 Centrifugal Compressors

(a) Applicability.

(1) The requirements of this section apply to centrifugal natural gas compressors located at natural gas transmission compressor stations, and natural gas underground storage facilities.

(2) The requirements of this section do not apply to centrifugal natural gas compressors that operate fewer than 200 hours over a rolling twelve (12) month period total provided that the owner or operator:

(i) Maintains a non-re-settable hour meter for operation, and

(ii) Maintains a record, for a minimum of five (5) years, of the operating hours per month, and

(iii) Provide a rolling twelve (12) month total calculation of hours to the Department once per year.

(b) Beginning January 1, 2023, centrifugal compressors with wet seals shall control the wet seal vent gas with the use of a vapor collection system as described in Subpart 203-8 or shall replace the wet seal with a dry seal.

(c) Beginning January 1, 2023, components on driver engines and compressors that use a wet seal or a dry seal shall comply with the LDAR requirements specified in Subpart 203-7, and;

(d) The compressor wet seal shall be measured annually by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument) while the compressor is running at normal operating temperature in order to determine the wet seal emission flow rate using one of the following methods:

(1) Vent stacks shall be equipped with a meter or instrumentation to measure the wet seal emissions flow rate; or,

(2) Vent stacks shall be equipped with a clearly identified access port installed at a height of no more than six (6) feet above ground level or a permanent support surface for making wet seal emission flow rate measurements.

(3) If the measurement is not obtained because the compressor is not operating for the scheduled test date and the remainder of the inspection period, then testing shall be conducted within fourteen (14) days of resumed operation. The owner or operator shall maintain for at least five (5) years, and make available upon request by the Department, a copy of operating records that document the compressor hours of operation and run dates and a signed statement from the responsible official in order to demonstrate compliance with this requirement.

(e) A compressor with a wet seal emission flow rate greater than three (3) scfm, or a combined flow rate greater than the number of wet seals multiplied by three (3) scfm, shall be successfully repaired within thirty (30) days of the initial flow rate measurement.

(1) An extension to the thirty (30) day deadline may be granted by the Department if the owner or operator can demonstrate that the parts or equipment required to make necessary repairs have been ordered and the owner or operator notifies the Department as specified in 203-10.3 to report the delay and provides an estimated time by which the repairs will be completed.

(f)) If parts are not available to make the repairs, the wet seal shall be replaced with a dry seal no later than eighteen (18) months after the exceeding measurement is made.

(g) The owner or operator shall maintain for at least five (5) years, a record of the flow rate measurement and shall report the result to the Department within sixty (60) days after completed.

(h) A centrifugal natural gas compressor with a wet seal emission flow rate measured above the standard specified in subdivision 203-4.3(e) and which is a critical component, shall be successfully repaired by the end of the next scheduled process shutdown or within twelve (12) months from the date of the initial flow rate measurement, whichever is sooner.

203-4.4 Reciprocating Compressors

(a) Applicability.

(1) The requirements of this section apply to reciprocating natural gas compressors located at natural gas transmission compressor stations, and natural gas underground storage facilities.

(2) The requirements of this section do not apply to reciprocating natural gas compressors that operate fewer than 200 hours over a rolling twelve (12) month period total, provided that the owner or operator:

(i) Maintains a non-resettable hour meter on the engine, and

(ii) Maintains a record, for a minimum of five (5) years, of the operating hours per month, and

(iii) Provides a rolling twelve (12) month total calculation of hours to the Department once per year.

(b) Beginning January 1, 2023, components on driver engines and compressors shall comply with the LDAR requirements specified in Subpart 203-7, except for the rod packing components subject to subdivision 203-4.4(c) and,

(c) The compressor rod packing or seal emission flow rate through the rod packing or seal vent stack shall be measured annually by direct measurement (high volume sampling, bagging, calibrated flow measuring instrument) while the compressor is running at normal operating temperature using one of the following methods:

(1) Vent stacks shall be equipped with a meter or instrumentation to measure the rod packing or seal emissions flow rate; or,

(2) Vent stacks shall be equipped with a clearly identified access port installed at a height of no more than six (6) feet above ground level or a permanent support surface for making individual or combined rod packing or seal emission flow rate measurements.

(3) If the measurement is not obtained because the compressor is not operating for the scheduled test date and the remainder of the inspection period, then testing shall be conducted within seven (7) days of resumed operation. The owner or operator shall maintain, and make available upon request by the Department, a copy of operating records that document the compressor hours of operation and run dates and a signed statement from the responsible official in order to demonstrate compliance with this requirement.

(d) Beginning January 1, 2023, compressor vent stacks used to vent rod packing or seal emissions shall be controlled with the use of a vapor collection system as specified in Subpart 203-8; or,

(e) A compressor with a rod packing or seal with a measured emission flow rate greater than two (2) scfm, or a combined rod packing or seal emission flow rate greater than the number of compression cylinders multiplied by two (2) scfm, shall be successfully repaired within thirty (30) days from the date of the initial emission flow rate measurement.

(1) An extension to the thirty (30) day deadline may be granted by the Department if the owner or operator can demonstrate that the parts or equipment required to make necessary repairs have been ordered and the owner or operator notifies the Department as specified in Section 203-10.3 to report the delay and provides an estimated time by which the repairs will be completed.

(f) The owner or operator shall maintain for at least five (5) years a record of the flow rate measurement and shall report the result to the Department within sixty (60) days after completed.

(g) A reciprocating natural gas compressor with a rod packing or seal emission flow rate measured above the standard specified as a critical component shall be successfully repaired by the end of the next scheduled process shutdown or within twelve (12) months from the date of the initial flow rate measurement, whichever is sooner.

203-4.5 Pipeline or Compressor Station Blowdown

(a) Applicability: Blowdown activity at compressor stations and transmission pipelines greater than ten thousand (10,000) standard feet cubed (scf).

(b) Requirements.

(1) Planned blowdowns.

(i) Provide notification to the Department and appropriate local authorities forty-eight (48) hours in advance of a blowdown event; the notification shall include, but not be limited to, the following information:

('a') Location

('b') Date

('c') Time and duration

('d') Contact person

('e') Reason for blowdown

('f') Estimated volume of release

(ii) If any of the information reported prior to the blowdown changed during or after the blowdown, another notification to the Department and appropriate local authorities shall be made with the updates no later than forty-eight (48) hours after the end of the blowdown.

(2) Unplanned blowdowns.

(i) Provide notification to the Department and appropriate local authorities within thirty (30) minutes of blowdown or as soon as it is safe to do so. The notification shall include, but not be limited to, the following information:

(‘a’) Location

(‘b’) Date

(‘c’) Time and duration

(‘d’) Contact person

(‘e’) Reason for blowdown

(‘f’) Estimated volume of release

203-4.6 Pigging

(a) Applicability: Pigging activity along natural gas pipelines.

(b) Requirements.

(1) Record and report pigging activities and estimated natural gas loss to the Department by March 31st of each year for the previous calendar year. The report shall include, but not be limited to:

(i) Location of activity.

(ii) Date of each activity.

(iii) Estimated volume of release for each activity.

203-5 Natural Gas Underground Storage Facilities

203-5.1 Natural Gas Storage Monitoring Requirements

(a) Applicability: The requirements of this section apply to natural gas underground storage facilities.

(b) Natural gas underground storage facility sources are subject to the LDAR requirements as specified in Subpart 203-7.

203-5.2 Metering and Regulating

(a) Metering and regulating components are subject to the LDAR requirements in Subpart 203-7.

203-6 City Gate

203-6.1 Metering and Regulating

(a) Applicability: The requirements of this section apply to all metering and regulating components at the City Gate.

(b) Metering and regulating components are subject to the LDAR requirements in Subpart 203-7.

203-7 Leak Detection and Repair.

(a) The requirements of this Subpart apply to the components subject to LDAR within this Part.

(b) The requirements of this Subpart do not apply to the following:

(1) Components that are buried below ground. The portion of well casing that is visible above ground is not considered a buried component.

(2) Components used to supply compressed air to equipment or instrumentation.

(3) Components operating under a negative gauge pressure or below atmospheric pressure.

(4) Temporary components used for general maintenance and used fewer than fifteen (15) days over a twelve (12) month period if the owner or operator maintains for at least five (5) years, and can make available at the request of the Department, a record of the date when the components were installed and removed.

(5) Pneumatic devices or pumps that use compressed air or electricity to operate.

(6) A compressor rod packing which is subject to annual emission flow rate testing as specified in section 203-4.4 of this Part.

203-7.1 Leak Detection Monitoring Techniques

(a) All owners and operators opting to comply using EPA Method 21, Volatile Organic Compound Leaks at 40 CFR Part 60, appendix A-7 (see table 1, section 200.9 of this Title), must meet the following requirements:

(1) For the purposes of complying with the fugitive emissions monitoring program using EPA Method 21, a fugitive emission is defined as an instrument reading of 500 ppm CH_4 and VOC.

(2) For purposes of instrument capability, the fugitive emissions definition shall be 500 ppm or greater CH_4 and VOC using a Flame Ionization Detector (FID)-based instrument.

(3) If an analyzer other than a FID-based instrument is used, a site-specific fugitive emission definition must be developed by the owner or operator that would be equivalent to 500 ppm CH_4 and VOC using a FID-based instrument. Such site-specific fugitive emission definition is subject to approval by the Department.

(b) Optical gas imaging. All owners and operators opting to comply using OGI must meet the following requirements:

(1) OGI equipment must be capable of imaging gases in the spectral range for CH_4 and VOC in the potential fugitive emissions.

(2) Calibration and maintenance procedures must comply with those recommended by the manufacturer.

(c) Alternative techniques. The Department may approve the use of an alternative technique that may be used in lieu of, or in combination with, OGI, Method 21, or other previously approved alternative methods. A proposed alternative method must be able to demonstrate that it is capable of identifying leaks and that it is at least as effective as the leak detection methods achieved using Method 21 or OGI. Owners and operators seeking approval of an alternative technique must submit the following information to the Department:

(1) Describe the technology and, at a minimum, include information on:

(i) Commercial availability of proposed alternative.

(ii) Other approved applications or uses.

(iii) Reliability (ability to detect emissions at a specified threshold and frequency, as well as identify or determine specific emission leak locations).

(iv) Capable of identifying leaks and is at least as effective as leak detection achieved using Method 21 or OGI demonstrated through field test data and modeling.

(v) Limitations/Restrictions (detection limits, weather/temperature/moisture, maximum/minimum operating parameters, other).

(vi) Data quality indicators for precision and bias.

(vii) Quality control and quality assurance procedures for proper operation.

(viii) Describe how the technology works

.

(ix) How the technology quantifies emissions.

(2) Description of use, maintenance and calibration.

(i) Description of where, when and how the alternative technique will be used.

(ii) User guide.

(iii) Manufacturer-recommended maintenance and calibration.

(iv) Calibration process.

(3) Process for recordkeeping.

(i) Frequency of data measurements.

(ii) Data logging capabilities.

(4) Training documentation or program, including any ongoing support provided.

(5) Provide any documentation associated with field testing or modeling to demonstrate leak detection is at least as effective as that achieved using Method 21 or OGI.

203-7.2 LDAR Frequency

(a) For Oil and Natural Gas Wells wellheads and components subject to Subpart 203-2, each well site shall be inspected by OGI, Method 21 or similar approved alternative method:

(1) Semiannually, or

(2) One (1) time over twenty-four (24) months if using an approved alternative method which offers continuous monitoring.

(b) For Natural Gas Gathering and Boosting components subject to Subpart 203-3, each gathering and boosting station shall be inspected by OGI, Method 21 or similar approved alternative method:

(1) Quarterly, or

(2) One (1) time over twenty-four (24) months if using an approved alternative method which offers continuous monitoring.

(c) Natural Gas Transmission Compressor Station components subject to Subpart 203-4 shall be inspected by OGI, Method 21 or similar approved alternative method:

(1) Bimonthly, at least forty-five (45) days apart, or

(2) One (1) time over twelve (12) months if using an approved alternative method which offers continuous monitoring.

(d) Storage Facility components subject to Subpart 203-5 shall be inspected by OGI, Method 21 or similar approved alternative method:

(1) Bimonthly, at least forty-five (45) days apart, or

(2) One (1) time over twelve (12) months if using an approved alternative method which offers continuous monitoring.

(e) City Gate components subject to Subpart 203-6 shall be inspected by OGI, Method 21 or similar approved alternative method:

(1) Quarterly, or

(2) One (1) time over twelve (12) months if using an approved alternative method which offers continuous monitoring.

203-7.3 Repair of leaks

(a) Upon detection of a leak from any equipment or component subject to this Part, the owner or operator shall affix to that component a weatherproof, readily visible tag that identifies the date and time of leak detection. The tag shall remain affixed to the component until the following conditions are met:

(1) The leaking component has been successfully repaired or replaced; and,

(2) The component has been re-inspected utilizing one of the methods specified in Subpart 203-7.

(b) The owner or operator shall maintain for at least five (5) years, and make available upon request by the Department, a record of leaks identified and shall report to the Department within sixty (60) days after repair re-inspection as defined in 203-7.3(d) is complete. Records shall include the date that the leak was detected, location of leak, the date that the leak was repaired and any delays that occurred.

(c) Leaks shall be repaired within thirty (30) days of identification unless one of the conditions of 203-7(f) apply.

(d) Repaired leaks shall be re-inspected using the methods specified in 203-7 within fifteen (15) days of repair.

(e) Critical components or critical process units shall be successfully repaired by the end of the next process shutdown or within twelve (12) months from the date of initial leak detection, whichever is sooner.

(f) A delay of repair may be granted by the Department under the following conditions:

(1) The owner or operator can demonstrate that the parts or equipment required to make necessary repairs have been ordered. A delay of repair to obtain parts or equipment shall not exceed thirty (30) days, unless the owner or operator notifies the Department to report the delay and provides an estimated time by which the repairs will be completed, or

(2) A gas service utility can provide documentation, in a form suitable to the Department, that a system has been temporarily classified as critical to reliable public gas system operation as ordered by the utility's gas control office.

203-8 Vapor Collection Systems and Vapor Control Devices

203-8.1 Vapor collection

(a) Beginning January 1, 2023, the following requirements apply to equipment that must be controlled using a vapor collection system and control device pursuant to the requirements specified in this Part.

(b) The vapor collection system shall direct the collected vapors to one of the following:

(1) A sales gas system; or,

(2) A fuel gas system.

(c) If no sales gas system or fuel gas system is available at the facility, the owner or operator must control the collected vapors by January 1, 2024 as follows:

(1) For facilities without an existing vapor control device, the owner or operator must install a new vapor control device as specified in section 203-8.1(d); or,

(2) For facilities currently operating an existing vapor control device that is required to control additional vapors as a result of this Part, if the device does not already meet the requirements specified in subdivision 203-8.1(d), the owner or operator must modify or replace the existing vapor control device to control vapors at the same efficiency or greater than that required in subdivision 203-8.1(d).

(d) Any vapor control device required in subdivision 203-8.1(c) must achieve at least 95 percent vapor collection control efficiency of total emissions and must meet all applicable federal and state requirements.

(e) Vapor collection systems and control devices may be taken out of service for up to thirty (30) days per rolling twelve (12) month period to perform maintenance while the facility continues to operate.

(1) A time extension to perform maintenance not to exceed fourteen (14) days per twelve (12) month period may be granted by the Department. The owner or operator is responsible for maintaining a record of the number of days per year that the vapor collection system or vapor control device is out of service and shall provide a record of such activity at the request of the Department.

(2) If an alternate vapor control device compliant with this section is installed prior to conducting maintenance and the vapor collection and control system continues to collect and control vapors during the maintenance operation consistent with the applicable standards specified in this Subpart, the event does not count towards the thirty (30) day limit.

(3) Vapor collection system and control device shutdowns that result from emergencies as defined in Section 201-1.5 of this Title are not subject to enforcement action, provided the equipment resumes normal operation immediately after the emergency and the requirements in Section 201-1.5 of this Title are met. Vapor collection system

and control device shutdowns that result from utility power outages do not count towards the thirty (30) day limit for maintenance.

203-9 Feasibility and Safety

(a) A repair or replacement may not be delayed unless it results in the following:

(1) a vented blowdown,

(2) a gathering and boosting station shutdown,

(3) a well shutdown,

(4) a well shut-in,

(5) rationale for continued operation is submitted to DEC to be later deemed technically infeasible or unsafe by the New York State Department of Public Service or other federal or state regulatory agency.

(b) The repair or replacement delay may be extended until the earliest event listed below.

(1) the next compressor station shutdown,

(2) the next gathering and boosting station shutdown,

(3) well shutdown,

(4) well shut-in,

(5) the next unscheduled, planned or emergency vent blowdown, or

(6) within one (1) year.

203-10 Reporting and Recordkeeping

203-10.1 Baseline Report

(a) Applicability: This section applies to all sources as described in Section 203-1.1.

(b) Owners or operators of components or processes subject to this Subpart must submit a report to the Department by March 31, 2023 or by March 31st of the year following initiation of operation.

(c) The report shall be in a format approved by the Department and shall list the number and type of components, including but not be limited to the following:

(1) separators
(2) storage vessels
(3) compressors
(4) gas drying systems
(5) pneumatic devices
(6) metering and regulating systems

203-10.2 Recordkeeping

(a) Reciprocating Natural Gas Compressors.

(1) Maintain, for at least five (5) years from the date of each leak concentration measurement, a record of each rod packing leak concentration measurement found above the minimum leak threshold as defined in Section 203-4.4.

(2) Maintain, for at least five (5) years from the date of each emissions flow rate measurement, a record of each rod packing emission flow rate measurement.

(3) Maintain, for at least five (5) years a record that documents the date(s) and hours of operation a compressor is operated in order to demonstrate compliance with the rod packing leak concentration or emission flow rate measurement in the event that the compressor is not operating during a scheduled inspection.

(4) Maintain, for at least five (5) years, records that provide proof that parts or equipment required to make necessary repairs have been ordered and installed.

(b) Centrifugal Natural Gas Compressors.

(1) Maintain, for at least five (5) years from the date of each emissions flow rate measurement, a record of each wet seal emission flow rate measurement.

(2) Maintain, for at least five (5) years, a record that documents the date(s) and hours of operation a compressor is operated in order to demonstrate compliance with the wet

seal emission flow rate measurement in the event that the compressor is not operating during a scheduled inspection.

(3) Maintain, for at least five (5) years, records that provide proof that parts or equipment required to make necessary repairs have been ordered and installed.

(c) Natural Gas Actuated Pneumatic Devices.

(1) Maintain, for at least five (5) years from the date of each emissions flow rate measurement, a record of the emission flow rate measurement

(d) Leak Detection and Repair.

(1) Maintain, for at least five (5) years from each inspection, a record of each LDAR inspection.

(2) Maintain, for at least five (5) years from the date of each inspection, component leak and repair documentation.

(3) Maintain records for at least five (5) years that provide proof that parts or equipment required to make necessary repairs have been ordered and installed.

(4) Maintain gas service utility records for at least five (5) years that demonstrate that a system has been temporarily classified as critical to reliable public gas operation throughout the duration of the classification period.

(e) Vapor Collection System and Vapor Control Devices.

(1) Maintain records for at least five (5) years that provide proof that parts or equipment required to make necessary repairs have been ordered and installed.

203-10.3 Reporting submissions and retention

(a) Reports shall be delivered to both the:

(1) Bureau Director, Bureau of Air Quality Planning, Division of Air Resources, 625 Broadway, Albany NY 12233, and

(2) The Regional Air Pollution Control Engineer in the corresponding Department Region in which the source is located.

(b) Source owners and operators must maintain reports for at least five (5) years and make them available to the Department upon request.

203-11 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.

Express Terms

6 NYCRR Part 200, General Provisions

(Existing Sections 200.1 through 200.8 remain unchanged.)

Existing Section 200.9, Table 1 is amended to add the following:

Regulation	CFR Cite	Availability
203-7.1(a)	40 CFR part 60, appendix A-7 (July 1, 2017)	*

6 NYCRR Part 203, Oil and Natural Gas Sector

6 NYCRR Part 200, General Provisions

Regulatory Impact Statement Summary

The New York State Department of Environmental Conservation (DEC or Department) is proposing new 6 NYCRR Part 203, "Oil and Natural Gas Sector" and attendant revisions to 6 NYCRR Part 200, "General Provisions."

Additionally, the Department plans to incorporate Part 203, once adopted, into New York's State Implementation Plan (SIP) and provide the revised SIP to EPA for review and approval.

Statutory Authority

The statutory authority for the promulgation of 6 NYCRR Part 203 and the attendant revision to 6 NYCRR Part 200 is found in the New York State Environmental Conservation Law (ECL), Sections 1-0101, 3-0301, 3-0303, 19-0103, 19-0105, 19-0107, 19-0301, 19-0302, 19-0303, 19-0305, 71-2103, 71-2105, and 75-0107.

Needs/Benefits

The primary need for this rulemaking is to protect the health and welfare of New York residents and resources by: 1) reducing methane (CH_4), a greenhouse gas, in support of the goals and requirements of the Climate Leadership and Community Protection Act (CLCPA),[1] 2) reducing associated volatile organic compounds (VOCs), an ozone precursor, and 3) fulfilling the requirements

[1] Chapter 106 of the Laws of 2019.

of the Environmental Protection Agency's (EPA) 2016 Control Techniques Guidelines (CTG) for the oil and gas industry.[2]

On July 18, 2019 Governor Cuomo signed into law the Climate Leadership and Community Protection Act, Chapter 106 of the Laws of 2019 (CLCPA). As added by the CLCPA, ECL Section 75-0107 requires a 40 percent reduction in Statewide GHG emissions from 1990 levels by 2030, and an 85 percent reduction from 1990 levels by 2050. ECL § 75-0107; 6 NYCRR Part 496. This proposal will support this overall requirement of the CLCPA by reducing statewide GHG emissions.

Ignoring the well-developed body of work on the benefits of reducing GHG and VOC emissions from this sector, on August 13, 2020, the EPA Administrator signed the finalized rollback amendments to the 2012 and 2016 rules affecting the oil and natural gas industry, titled, respectively, "Oil and Natural Gas Sector: New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule" (2012 Rule) and "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule" (2016 Rule). As a result of this lack of protection, DEC must develop regulations for both new and existing sources in this sector with the goal of lowering CH_4 and VOC emissions within New York.

Methane is a GHG that is emitted from both human activities and natural processes.[3] GHGs like CH_4 trap heat in the atmosphere, which is a driving force of climate change. CH_4 is also a precursor for tropospheric ozone (O_3) which is harmful to human health and crop production.

[2] 81 FR 74798 (October 27, 2016).
[3] https://www.epa.gov/ghgemissions.

Estimates show that methane emissions from the oil and gas supply chain are 63% higher than the EPA Greenhouse Gas Inventory (GHGI).[4] These higher estimates make it crucial to address methane emissions from the oil and gas industry.

The New York-Northern New Jersey-Long Island, NY-NJ-CT metropolitan area (New York metropolitan area, or NYMA) is designated "nonattainment" with a "serious" classification for the 2008 ozone NAAQS and "nonattainment" with a "moderate" classification for the 2015 ozone NAAQS. New York submitted a State Implementation Plan (SIP) for the 2008 ozone NAAQS in 2020 and is required to submit an additional SIP for the 2015 ozone NAAQS by August 3, 2021. These SIPs must demonstrate how the NYMA plans to attain the 2008 NAAQS by July 20, 2021 and the 2015 NAAQS by August 3, 2024.

Despite DEC's aggressive emission reduction efforts and calls for EPA to address interstate transport of ozone, the NYMA continues to struggle to attain the 2008 and 2015 NAAQS. More in-state emission reductions are needed to assist the area with attaining both ozone standards.

A variety of sources contribute to CH_4 emissions along the natural gas supply chain. VOCs are also released from equipment along the supply chain and these direct emissions are precursors to the production of ozone which is a regulated criteria pollutant harmful to human health.

Proposal

The proposed requirements are expected to reduce CH4 and VOC emissions from the oil and natural gas sector in New York State. The requirements apply at natural gas and oil wells, natural gas

[4] Alvarez et al., Assessment of methane emissions from the U.S. oil and gas supply chain, July 2018.

gathering lines, natural gas transmission, natural gas storage and areas where natural gas metering and regulating occurs.

If a potential to emit (PTE) threshold of 6 tons per year is exceeded, storage vessels are required to install a vapor recovery system which is subject to leak detection and repair (LDAR). The wellhead, piping, heater separators and pneumatic devices will all be subject to LDAR requirements.

This proposal allows for optical gas imaging (OGI) or EPA Method 21 as pre-approved methods for leak detection. In addition, the proposal allows for alternative techniques for leak detection which may be submitted to the Department for approval. Alternatives must be at least as effective as OGI or Method 21 in identifying leaks. The Department is also proposing an option to reduce the frequency of LDAR if an approved alternative method which offers continuous monitoring is utilized. A study focused on leak detection found that, in 31% of the cases, emissions concentrations either stayed within the same range or increased after leak repairs.[5] Therefore, the Department also proposes monitoring after leaks are repaired to ensure that leaks are successfully fixed.

Collected vapors may be sent to the sales gas system or the fuel gas system. If these options are not available, then the collected vapors must be routed to an existing or new vapor collection system that must achieve at least ninety-five percent vapor control efficiency. Vapor collection systems will also be subject to LDAR.

[5] Carbon Limits, Statistical Analysis of Leak Detection and Repair in Europe, November 2017.

This proposal requires LDAR at well sites (semiannually), gathering and boosting sources (quarterly), transmission compressor stations (bimonthly), storage facilities (bimonthly), and the City Gate (quarterly).

The proposal requires each source to submit a list of the components that are located at its site.

The Department expects the following annual CH_4 and VOC reductions if this proposal is adopted. Until sources are assessed, there is uncertainty about the number of sources which will be required to install controls.

Table 1: Summary of potential annual reductions

	Metric tons (MT) CH4	**MTCO2e (100 yr GWP)**	**MTCO2e (20 yr GWP)**	**Tons of VOC**
Storage Vessels	6,309-31,545	157,725 - 788,625	529,956 – 2,649,780	1,009-5,047
Reciprocating Compressors	708	17,700	59,472	113
Centrifugal Compressors	3,164 – 15,819	79,100-395,475	265,776 – 1,328,796	506-2,531
LDAR	4,462	111,550	374,808	714
Total Emissions Reductions	14,643-52,534	366,075-1,313,350	1,230,012 – 4,412,856	2,343-8,405
2017 NYS Oil/Gas CH4 Emissions	106,561	2,664,182	8,951,124	
% Emissions Reductions within Sector	13% - 49%			

<u>Costs</u>

Storage Vessels: The 2016 EPA CTG lists capital costs to install vapor recovery at $171,538 and annual costs at $28,230.

Compressors – Reciprocating: Based on typical operation, EPA estimates the cost to be $2,153 per compressor per year[6] which translates into $165,781 per year for all 77 permitted reciprocating compressors in the state. [7]

Compressors – Wet Seal Centrifugal: The capital cost to retrofit a gas capture system is estimated in the Environmental Defense Fund's (EDF) 2014 report at $50,000 for a 95% reduction of natural gas loss. A survey of the 40 centrifugal compressors permitted in New York indicate that most already have a dry seal, so the Department does not expect high costs associated with this requirement.

LDAR at Wells: Annual costs for LDAR personnel or consultants and repairs are estimated at $2,285, ICF estimated this cost to be $2,006.[8]

LDAR at Compressors: EPA estimates a capital cost for semiannual LDAR at gathering and boosting stations of $2,393 and annual costs at $13,534.[9] EDF estimates an annual cost of $6,017 for quarterly LDAR, for gathering and boosting stations and transmission compressor stations.[10] To account for the costs associated with performing bimonthly LDAR, quarterly LDAR costs are

[6] EPA 2016 CTG, Table 5-5.
[7] EPA Gas Star program, "Reducing Methane Emissions From Compressor Rod Packing Systems." https://www.epa.gov/sites/production/files/2016-06/documents/ll_rodpack.pdf.
[8] ICF, 2014, Table 3-4.
[9] EPA CTG, 2016, Table 9-26.
[10] ICF, 2014, Table 3-4.

multiplied by 1.5 (50% increase), resulting in an annual cost estimate of $9,025.5 (EDF) or $20,301 (EPA).

It is estimated that this rulemaking and ongoing support will require 1.5 full time equivalent (FTE) or $237,500[11] during the first year and 1.0 FTE annually thereafter.

This proposal may also impact other Departments such as the Department of Public Service (DPS). It is unknown exactly how many FTE's will be required to support any requests for rate cases from the impacted sources, however it is expected that there will be additional workload.

Extrapolating from United States Energy Information Administration data indicates that over 5.5 billion dollars passed through the natural gas market in New York in 2019. [12]

Table 2: Summary of Potential Costs

	Quantity	Initial Cost Low	Initial Cost High	Annual Cost Low	Annual Cost High
Storage Vessels vapor recovery	10% - 50%	34,787,906	173,939,532	5,725,044	28,625,220
Compressor - recip	All compressors			165,781	165,781
Compressor - centrifugal	10% - 50%	200,000	1,000,000		
LDAR - wells	All wells	369,261	369,261	924,766	1,053,385
LDAR - compressors	All compressors			288,816	649,632
TOTAL		35,357,167	175,308,793	7,104,407	30,494,018

[11] Assumptions: Grade 24 pay rate of $97,448 per year and an overhead rate of 62.48 percent. Per: https://www.osc.state.ny.us/agencies/guide/MyWebHelp/#VII/9/9.htm.

[12] EIA Natural Gas Summary, 2019. https://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_SNY_a.htm.

Estimated costs are summarized in Table 2 and demonstrate that a large portion, over eighty percent, of the costs fall into the potential for storage vessel vapor recovery. This is also the category where the Department is uncertain if any vessels will be required to install these controls. After storage vessels are assessed, it may result that very few, if any, will actually trigger the requirement to install vapor recovery which would eliminate over eighty percent of these costs.

Costs of Emissions

Using the estimated emissions reductions calculated (Table 1), Table 3 shows the cost of the missed opportunity to reduce these emissions. It is important to note that not all potential emission reductions have been calculated as data does not exist on the amount of reductions. For example, this proposal requires LDAR at the Citygate which does not have an estimated reduction factor.

Table 3			
Annual Cost of Methane			
Total Potential Emissions Reductions ($MTCH_4$)	14,643 – 52,534		
Social Cost if Reductions are not achieved (2020 dollars)	\$96,321,654 - \$345,568,652	\$40,736,826 - \$146,149,588	\$22,359,861 - \$80,219,418
	1% Discount Rate (\$6,578/ metric ton)	**2% Discount Rate (\$2,782/ metric ton)**	**3% Discount Rate (\$1,527/ metric ton)**

There are also costs associated with VOC emissions and the formation of ozone, including increased hospital visits, sick days and other associated costs.

Comparing Tables 2 and 3 demonstrates that the cost of reducing emissions from these sources is significantly less than the value achieved by the reductions.

Local Government Mandates

The proposed regulation does not impose a mandate on local governments. Local governments have no additional compliance obligations as compared to other subject entities.

Paperwork

In general, this proposal requires impacted sources to maintain records for five years and submit records within 60 days of certain events and annually for maintenance.

Federal Regulation

This proposal implements EPA's CTG, but adds methane and other requirements in order to be fully protective.

Alternatives

Alternative #1 – No Action: If the Department chooses not to act, this will constitute a violation of the Clean Air Act.

Alternative #2 – Include Required Continuous Emission Monitoring at all sites; The Department did not choose this alternative because at this time the Department does not believe that CEM technology is as advanced as needed.

Alternative #3 – Remove LDAR requirements: The Department did not choose this alternative because research clearly demonstrates that significant reductions are achieved through LDAR.

Federal Standards

EPA has both a federal NSPS and a CTG that places requirements on this sector. This proposal satisfies the CTG requirement while addressing the State's commitment to reduce GHG emissions under the CLCPA. The requirements of this proposal include those set by the EPA, and it also includes requirements to segments within the sector and additional requirements across the entire sector that EPA does not include in order to achieve the NAAQS and protect human health and welfare.

Compliance Schedule

The Department has proposed an initial compliance start date of January 1, 2023. The first report must be submitted by March 31, 2023.

6 NYCRR Part 203, Oil and Natural Gas Sector

6 NYCRR Part 200, General Provisions

Regulatory Impact Statement

The New York State Department of Environmental Conservation (DEC or Department) is proposing new 6 NYCRR Part 203, "Oil and Natural Gas Sector" and attendant revisions to 6 NYCRR Part 200, "General Provisions." (collectively, Part 203). The primary need for this rulemaking is to protect the health and welfare of New York residents and resources by: 1) reducing methane (CH_4), a greenhouse gas (GHG), in support of the goals and requirements of the Climate Leadership and Community Protection Act (CLCPA);[1] 2) reducing associated volatile organic compounds (VOCs), an ozone precursor; and 3) fulfilling the requirements of the United States Environmental Protection Agency's (EPA) 2016 Control Techniques Guidelines (CTG) for the oil and gas industry.[2]

Additionally, the Department plans to incorporate Part 203, once adopted, into New York's State Implementation Plan (SIP) and provide the revised SIP to EPA for review and approval.

Statutory authority

The statutory authority for the promulgation of 6 NYCRR Part 203 and the attendant revisions to 6 NYCRR Part 200 is found in the New York State Environmental Conservation Law (ECL), Sections 1-0101, 3-0301, 3-0303, 19-0103, 19-0105, 19-0107, 19-0301, 19-0302, 19-0303, 19-0305, 71-2103, 71-2105, and 75-0107.

[1] Chapter 106 of the Laws of 2019.
[2] 81 FR 74798 (October 27, 2016).

ECL Section 1-0101. This section declares it to be the policy of the state to conserve, improve and protect its natural resources and environment and control air pollution in order to enhance the health, safety and welfare of the people of the state and their overall economic and social well-being. Section 1-0101 further expresses, among other things, that it is the policy of the state to coordinate the state's environmental plans, functions, powers and programs with those of the federal government and other regions and manage air resources so that the state may fulfill its responsibility as trustee of the environment for present and future generations. This section also provides that it is the policy of the state to foster, promote, create and maintain conditions by which man and nature can thrive in harmony by providing that care is taken for air resources that are shared with other states.

ECL Section 3-0301. This section states that it shall be the responsibility of DEC to carry out the environmental policy of the state. In furtherance of that mandate, Section 3-0301(1)(a) gives the Commissioner authority to "[c]oordinate and develop policies, planning and programs related to the environment of the state and regions thereof...". Section 3-0301(1)(b) directs the Commissioner to promote and coordinate management of, among other things, air resources "to assure their protection, enhancement, provision, allocation, and balanced utilization consistent with the environmental policy of the state and take into account the cumulative impact upon all of such resources in making any determination in connection with any license, order, permit, certification or other similar action or promulgating any rule or regulation, standard or criterion." Pursuant to ECL Section 3-0301(1)(i), the Commissioner is charged with promoting and protecting the air resources of New York including providing for the prevention and abatement of air pollution. Section 3-0301(2)(a) permits the Commissioner to adopt rules and regulations to carry out the purposes and provisions of the ECL. Section 3-0301(2)(m) gives the Commissioner authority to "[a]dopt such rules, regulations, and procedures as may be necessary, convenient or desirable to effectuate the purposes of this chapter."

ECL Section 3-0303. This section requires that DEC formulate and, from time to time, revise a statewide environmental plan for the management and protection of the quality of the environment and the natural resources of the state. In formulating this plan and any revisions, DEC is required to conduct public hearings, cooperate with other departments, agencies and government officials, and any other interested parties, and obtain assistance and data as may be necessary from any department, division, board, bureau, commission or other agency of the state or political subdivision or any public authority to enable DEC to carry out its responsibilities.

ECL Section 19-0103. This section declares that it is the policy of New York State to maintain a reasonable degree of purity of air resources. In carrying out such policy, DEC is required to balance public health and welfare, the industrial development of the state, propagation and protection of flora and fauna, and the protection of personal property and other resources. To that end, DEC is required to use all available practical and reasonable methods to prevent and control air pollution in the state.

ECL Section 19-0105. This section declares that it is the purpose of Article 19 of the ECL to safeguard the air resources of the state under a program which is consistent with the policy expressed in Section 19-0103 and in accordance with other provisions of Article 19.

ECL Section 19-0107. This section provides definitions to be used in the application of the requirements of Article 19 of the ECL. Under these definitions, just like other GHGs, methane is an "air contaminant" that causes "air pollution."

ECL Section 19-0301. This section authorizes DEC to adopt regulations to prevent and control air pollution in such areas of the state that are affected by air pollution, develop a general comprehensive plan for the control and abatement of existing air pollution and for the control and prevention of new air pollution and cooperate with government agencies and other states or interstate agencies with respect to the control of air pollution.

ECL Section 19-0302. This section states that permit applications, renewals, modifications, suspensions and revocations are governed by rules and regulations adopted by DEC, and that permits issued may not include performance, emission or control standards more stringent than any standard established by the Act or EPA unless such standards are authorized by rules or regulations.

ECL Section 19-0303. This section provides that the terms of any air pollution control regulation promulgated by DEC may differentiate between particular types and conditions of air pollution and air contamination sources. Additionally, this section requires the Department to include analysis in the Regulatory Impact Statement explaining state regulatory requirements that are more stringent than those found in the Act or its implementing regulations. The requirements of this proposal include those set by the EPA Control Techniques Guideline; however, it also includes requirements to segments within the sector and additional requirements across the entire sector that EPA does not include. The Department further discusses the decision to be more stringent than EPA regulations below.

ECL Section 19-0305. This section authorizes DEC to enforce the codes, rules and regulations established in accordance with Article 19.

ECL Sections 71-2103 and 71-2105. These sections include provisions for the civil and criminal enforcement of Article 19 of the ECL.

ECL Section 75-0107. This section requires a 40 percent reduction in Statewide GHG emissions from 1990 levels by 2030, and an 85 percent reduction from 1990 levels from 2050. See also 6 NYCRR Part 496. Under the CLCPA, statewide GHG emissions include both GHG emissions from all sources located within the state and certain sources that are located outside of the state that are associated with in-state energy consumption. In particular, the statute requires that statewide GHG emissions include both: (1) “the total annual emissions of greenhouse gases produced within the state from anthropogenic sources,” and (2) “greenhouse gases produced outside of the state that are associated with [a] the generation of electricity imported into the state and [b] the extraction and transmission of fossil fuels imported into the state.” ECL § 75-0101(13). Moreover, the CLCPA defines “carbon dioxide equivalent” as a measurement of global warming potential (GWP) based on a twenty-year timeframe. ECL § 75-0101(2). For methane, this carbon dioxide equivalent value is currently set at 84. 6 NYCRR § 496.5.

<u>Legislative objectives</u>

Article 19 of the ECL was enacted to safeguard the air resources of New York from pollution and ensure the protection of the public health and welfare, the natural resources of the state, and physical property by integrating industrial development with sound environmental practices. It is the policy of the state to require the use of all available, practical and reasonable methods to prevent and control air pollution in New York. To facilitate this objective, the Legislature granted specific powers and duties to DEC, including the power to adopt and promulgate regulations to prevent, control and prohibit air pollution. The provisions cited above clearly provide DEC with the requisite authority to create this regulation. Moreover, as acknowledged by the Legislature through its enactment of the CLCPA, significant reductions of GHG emissions, including methane, are necessary to mitigate the ongoing impacts of climate change on New York State. By reducing methane emissions, this regulation will further the goals and requirements of the CLCPA.

Finally, because it will lead to reductions in emissions of methane, a GHG, the proposed promulgation of Part 203 is consistent with the goals and requirements of the CLCPA. The CLCPA establishes Statewide GHG emission reduction requirements and renewable and clean energy generation requirements.

Needs and benefits

As noted in the introduction the primary need for this rulemaking is to protect the health and welfare of New York residents and resources by: 1) reducing CH_4 in support of the goals and requirements of the CLCPA, 2) reducing associated VOCs, and 3) fulfilling the requirements of the EPA's 2016 CTG.

The CTG contains requirements to lower VOC emissions from existing sources. When originally proposed and adopted, the CTG was accompanied by a New Source Performance Standard (NSPS) which addressed both CH_4 and VOC emissions from new sources. The

Department is moving forward with this proposal to address both CH_4 and VOCs from all applicable oil and natural gas sources. The emission reductions are achieved through the capture and reduction of released natural gas. As a result, the Department will achieve a greater level of reduction than required by the CTG through this proposal.

The Department's proposal covers both new and existing sources. The EPA finalized a regulation in 2016 for new sources which has gone through various levels of rollbacks since that time. Most recently, the EPA finalized rollbacks to the regulation for new sources which is inconsistent with the original regulation as well as this proposal. Although this proposal covers existing as well as new sources, there are some areas of duplication between the EPA regulation and this proposal. The Department does not believe that, in its current iteration, the EPA regulation is protective of the health and welfare of U.S. residents.

Background on Methane

On July 18, 2019, Governor Cuomo signed into law the CLCPA, Chapter 106 of the Laws of 2019. The CLCPA is intended to "create a comprehensive regulatory program to reduce greenhouse gas emissions that corresponds with emission reduction goals as set forth in Executive Order 24, the State Energy Plan, and the [United States Global Change Research Program] and [Intergovernmental Panel on Climate Change] projections." CLCPA §1. As noted above under Statutory Authority, ECL Section 75-0107 requires a 40 percent reduction in Statewide GHG emissions from 1990 levels by 2030, and an 85 percent reduction from 1990 levels from 2050. ECL § 75-0107; 6 NYCRR Part 496. This proposal will support these overall requirements of the CLCPA, as established in ECL § 75-0107 and implemented by DEC through 6 NYCRR Part 496, of lowering statewide GHG emissions.

Ignoring the well-developed body of work on the benefits of reducing GHG and VOC emissions from this sector, on August 13, 2020, the EPA Administrator signed the final amendments to the 2012 and 2016 rules affecting the oil and natural gas industry, essentially a rollback of critical environmental regulations. These rollbacks affected two previous rules titled, respectively, “Oil and Natural Gas Sector: New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule” (2012 Rule)[3] and “Oil and Natural Gas Sector: Emission Standards for New, Reconstructed and Modified Sources; Final Rule” (2016 Rule).[4] Those rules initially established NSPS for VOCs and GHGs, in the form of limitations on VOCs and CH_4, for that industry.[5] In its announcement of the rollback of requirements on August 13, 2020, EPA stated that “[t]hese rules will provide significant benefits to our small oil and natural gas producers that make up over 80 percent of the industry[,]”[6] while neglecting to show any benefit to the environment or human health, their primary function. As a result of this lack of protection, DEC must develop regulations for both new and existing sources in this sector with the goal of lowering CH_4 and VOC emissions within New York.

CH_4 is a GHG that is emitted from both human activities (e.g. agriculture, oil & gas sector, waste) and natural processes (e.g. wetlands).[7] GHGs like CH_4 trap heat in the atmosphere, which is a driving force of climate change. GWP measures how much energy the emissions of 1 ton of a gas will absorb over a given period of time, relative to the emissions of 1 ton of CO_2. CH_4 is a potent

[3] 77 FR 49490 (August 16, 2012).
[4] 81 FR 35824 (June 3, 2016).
[5] Docket ID No. EPA-HQ-OAR-2010-0505.
[6] EPA, 2020. https://www.epa.gov/sites/production/files/202008/documents/og_actions.overviewfactsheet.final.8.13.2020.pdf.
[7] https://www.epa.gov/ghgemissions.

GHG with a 100-yr GWP of 28-34 and a 20-yr GWP of 84-86.[8] In addition to being a GHG, CH_4 is a precursor for tropospheric ozone (O_3) which is harmful to human health and crop production. Therefore, reducing CH_4 emissions results in a two-fold benefit because it is both a GHG and an ozone precursor.

In a nationwide study of the natural gas transmission and storage sector, the performance gap between companies that volunteered for the study and those that did not reinforced the need for governments to set standards to manage CH_4 emissions. Reported emissions from non-partner facilities were 1.4 times larger than those reported by facilities that participated in the study.[9] Given the variance in emissions from natural gas facilities, it is crucial for governments to set standards to manage CH_4 emissions for the natural gas industry. Furthermore, estimates show that CH_4 emissions from the oil and gas supply chain are 63% higher than the EPA GHG inventory (GHGI).[10] These estimates make it crucial to address CH_4 emissions from the oil and gas industry.

Background on Ozone

In March of 2008, the EPA lowered the eight-hour National Ambient Air Quality Standard (NAAQS) for ozone from 0.08 parts per million (ppm) to 0.075 ppm.[11] EPA lowered the NAAQS again on October 1, 2015 to 0.070 ppm.[12] Both standards are currently in effect. Ozone NAAQS attainment status is determined from the monitor with the highest "design value" within the designated area. The "design value" is calculated as the 4th highest daily maximum eight-hour ozone

[8] Myhre et al. Anthropogenic and Natural Radiative Forcing. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. For purposes of the Department's Part 496, Statewide Greenhouse Gas Emission Limits regulation, which implements the requirements of ECL § 75-0107, the 20-yr GWP of CH_4 is 84.
[9] Subramanian et al., Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol, February 2015.
[10] Alvarez et al., Assessment of methane emissions from the U.S. oil and gas supply chain, July 2018.
[11] 73 FR 16436 (March 27, 2008), codified at 40 CFR section 50.15. Attainment of the 2008 ozone NAAQS is determined when the fourth highest daily maximum 8-hour average ambient air quality ozone concentration, averaged over three year, is less than or equal to 0.075 ppm.
[12] 80 FR 65292 (October 26, 2015).

concentration, averaged over three years,[13] and is compared to the NAAQS to determine attainment status and classification.

The New York-Northern New Jersey-Long Island, NY-NJ-CT metropolitan area (New York metropolitan area, or NYMA) is designated "nonattainment" with a "serious" classification for the 2008 ozone NAAQS and "nonattainment" with a "moderate" classification for the 2015 ozone NAAQS. New York submitted a State Implementation Plan (SIP) for the 2008 ozone NAAQS in 2020 and is required to submit an additional SIP for the 2015 ozone NAAQS by August 3, 2021. These SIPs must demonstrate how the NYMA plans to attain the 2008 NAAQS by July 20, 2021 and the 2015 NAAQS by August 3, 2024.

While the current "design value" for monitors within New York State is 0.075 ppm, the current "design value" for the entire NYMA ozone nonattainment area is 0.082 ppm based on data from monitors in Westport and Stratford, Connecticut. This clearly demonstrates that despite DEC’s aggressive emission reduction efforts, and calls for EPA to address interstate transport of ozone, the NYMA continues to struggle to attain the 2008 and 2015 NAAQS. Therefore, more in-state emission reductions are needed to assist the area with attaining both ozone standards and protecting the health of New York residents and the environment.

Background on the Oil and Natural Gas Sector

New York State has a 200-year history with oil and gas production and distribution and with that history comes the existence of conventional wells and infrastructure throughout the State, concentrated in the Western Tier. While the history is long, the industry is changing quickly and has

[13] Code of Federal Regulations, Part 50 Appendix I.

been spotlighted by stakeholders aware of and concerned about air emissions and potential emissions increases from this sector as demand has grown.

The U.S. Energy Information Administration (EIA) projects that by 2040, total natural gas production in the United States will increase by 40% and oil production will increase by over 27%.[14] In New York State while total oil and natural gas production has fluctuated up and down since 1979 overall production has generally increased over time. For example, when the Trenton Black River gas was extracted between 2000 and 2007 gas production increased by as much as 35% from previous years.

The New York State Energy Research and Development Authority (NYSERDA) has estimated that natural gas leakage in New York State has emitted between 2 and 5.2 million metric tons of carbon dioxide equivalents (MMtonCO2e) per year since 1990 expressed as a 100-yr GWP.[15] Using the CLCPA's 20-yr GWP metric, this would equate to between 6.72 and 17.5 MMtonCO_2e. CH_4, a primary component of natural gas, is a potent GHG, and a variety of sources contribute to CH_4 emissions along the natural gas supply chain. VOCs are also released from equipment along the supply chain and these direct emissions are precursors to the production of ozone which is a regulated criteria pollutant harmful to human health and the environment.

Table 1 shows the current estimates for GHGs from New York's oil and natural gas sector.

[14] US Energy Information Administration. Annual Energy Outlook; U.S. Department of Energy: Washington D.C., 2015.< http://www.eia.gov/beta/aeo/#/?id=1-AEO2015&region=0-0&cases=ref2015&start=2012&end=2040&f=L&linechart=1-AEO2015.3.>.

[15] NYSERDA. Web. http://www.nyserda.ny.gov/-/media/Files/EDPPP/Energy-Prices/Energy-Statistics/greenhouse-gas-inventory.pdf.

Table 1: 2017 GHG and VOC emissions from the oil and natural gas sector in New York16 (in metric tons)[16]				
Sub-Sector	**MTCO2e (100 yr GWP)**	**MTCO2e (20 yr GWP)**	**MTCH4**	**MTVOC**
Production	371,862	1,249,416	14,874	2,380
Gathering & Processing	32,627	109,620	1,305	209
Transmission	1,143,021	3,840,564	45,721	7,315
Storage	631,361	2,121,336	25,254	4,041
Distribution	296,142	995,064	11,846	1,895
Abandoned Wells	4,547	15,288	182	29
Degreasing	2,696	9,072	108	17
Well Completions	808	2,688	32	5
Meters	181,095	608,496	7244	1,159
Total	2,664,159	8,951,544	106,566	17,051

There are 32 permitted compressor stations with a total of 117 permitted compressors in New York State. New York also has 27 underground natural gas storage sources. While this proposal establishes requirements for metering and regulating stations actual counts for these stations are not well-established. It has been estimated that there may be somewhere between three to four thousand metering and regulating stations in New York. In 2018 there were 3,411 active oil wells and 6,729 active gas wells. In 2018, 10.6 billion cubic feet (bcf) of natural gas and 224,717 barrels (bbl) of oil were extracted from New York's wells. These well locations are shown in Figure 1.

[16] New York State Energy Research and Development Authority (NYSERDA). 2019. "New York State Oil and Gas Sector Methane Emissions Inventory." NYSERDA Report Number 19-36. Prepared by Abt Associates, Rockville, MD and Energy and Environmental Research Associates, LLC, Pittsford, NY. nyserda.ny.gov/publications. VOC emissions estimated by weight percent of methane with the assumption of a natural gas stream with volumetric percent of 95% methane and 5% VOC.

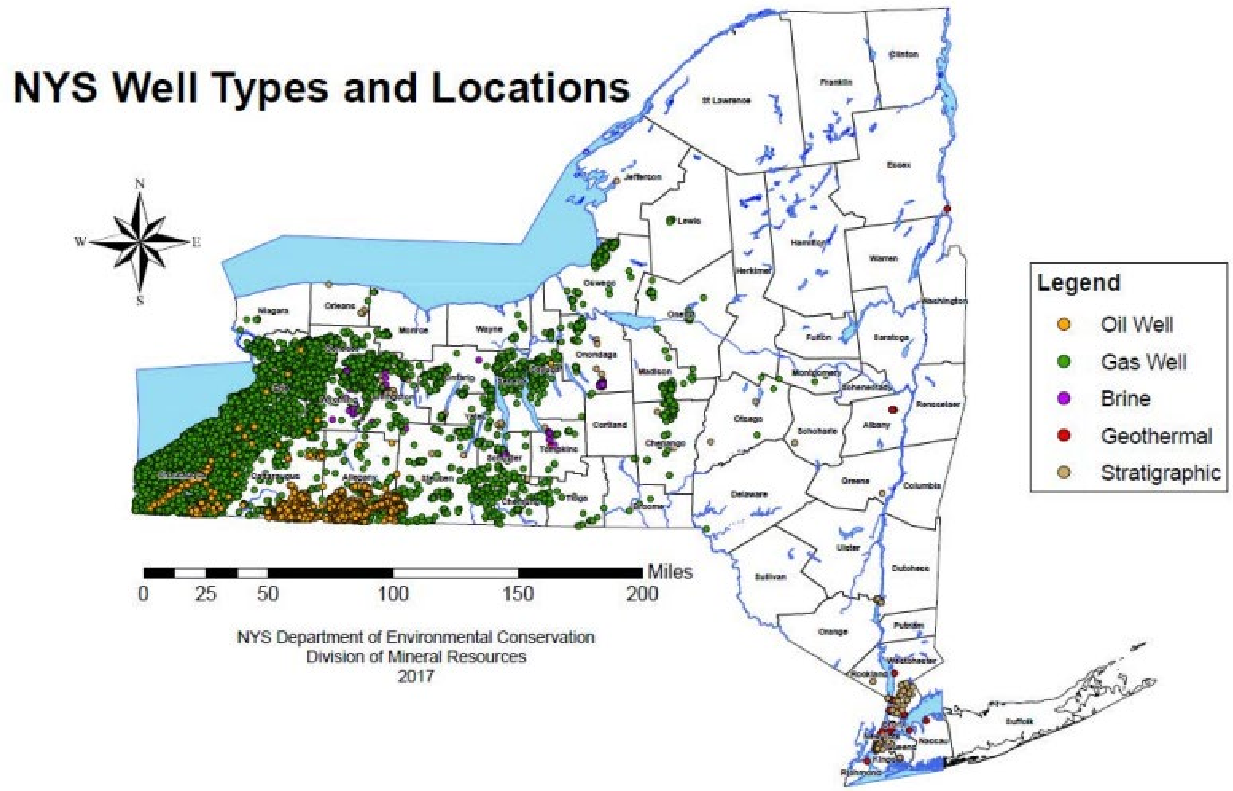

Figure 1: Well locations

To further characterize the oil and natural gas sector, the Department believes it is important to establish the concept of high-emitting sources, also known as "super-emitters." Studies suggest that methane emissions are underestimated from this sector based on atmospheric research.[17,18] This underestimation may be due to super-emitters which represent a small fraction of sites but may be responsible for a large fraction of emissions. Many studies support this phenomenon[19,20,21,22] and it

[17] Brandt, A.R., et al. 2014. Methane Leaks from North American Natural Gas Systems. Science. Vol. 343.
[18] Miller, S.M., et al. 2013. Anthropogenic Emissions of Methane in the United States. Proceedings of the National Academy of Sciences. December 10, 2013.
[19] Brandt, A.R., et al. 2014. Methane Leaks from North American Natural Gas Systems. Science. Vol. 343.
[20] Lamb, Brian K, et al. 2015. Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States. Environmental Science & Technology.
[21] Zavala-Araiza, Daniel, et al. 2015. Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites. Environmental Science & Technology.
[22] Zimmerle, Daniel J., et al. 2015. Methane Emissions from the Natural Gas Transmission and Storage System in the United States. Environmental Science & Technology.

serves as a large part of the basis behind the Department proposal to cover all affected sources in New York State.

Proposal

The proposed requirements are expected to reduce CH_4 and VOC emissions from the oil and natural gas sector in New York State. The requirements apply to all natural gas and oil wells, natural gas gathering lines, natural gas transmission, natural gas storage and areas where natural gas metering and regulating occurs.

Well Sites: Oil and gas well sites in New York are simpler than those found in other regions of the United States because most of the natural gas extracted in New York is very dry. This dry gas does not have to be processed to the extent required in other regions before it can enter a natural gas transmission pipeline. There may be storage vessels, or tanks, at well sites which may contain produced water, separation products or other fluids. These storage vessels may emit VOCs or CH_4. The proposal includes requirements that if a VOC potential to emit (PTE) threshold of 6 tpy is exceeded, storage vessels at well sites are required to install a vapor recovery system which is subject to leak detection and repair (LDAR) requirements.

A finished and producing natural gas well will also include flow lines and gathering lines and may include heater separators. Pneumatic devices may be used for maintaining process conditions. The wellhead, piping, heater separators and pneumatic devices will all be subject to LDAR requirements.

Gathering and Boosting Stations: Gathering and boosting stations collect gas from multiple wells and move it toward a transmission pipeline. Components at these stations typically include compressors to increase the pressure of the gas to that needed to move it into the pipeline, pneumatic devices and pumps to maintain process conditions and storage vessels. The proposed regulation establishes operational standards for compressors and LDAR standards for the compressors as well as all of the other components. If a VOC PTE threshold of 6 tpy is exceeded, storage vessels at these stations are required to install a vapor recovery system which is subject to LDAR requirements.

Natural Gas Transmission Pipeline and Compressor Stations: The function of natural gas transmission pipelines and compressor stations is to move gas down a pipeline by either increasing the pressure of the gas in the pipeline from the pressure coming from the gathering and boosting stations or maintaining the high pressure needed in the transmission pipeline when pipeline flow pressure decreases. The proposed regulation establishes operational standards and LDAR standards for compressors and other components. If a VOC PTE threshold of 6 tpy is exceeded, storage vessels at compressor stations are required to install a vapor recovery system which is subject to LDAR requirements. In addition, the Department is requesting data for all pigging activities.

Natural Gas Underground Storage: Natural gas is stored in underground locations to be used for system balancing or saved for winter months when demand for natural gas to heat homes and businesses increases. The natural gas is stored in what are often depleted natural gas or oil reservoirs but may be any natural or artificial cavern or geologic dome, sand or stratigraphic trap, whether or not previously occupied by or containing oil or natural gas. Storage sources typically include compressors to move the natural gas, pneumatic devices and pumps to maintain system conditions and storage vessels to store any liquids removed. The proposed regulation establishes operational standards for compressors and LDAR standards for the compressors as well as all of the other components. If a PTE threshold of 6 tpy of VOC is exceeded, storage vessels located at underground storage sites are required to install a vapor recovery system which is subject to LDAR requirements.

Leak Detection and Repair: LDAR is the process of locating and repairing leaks from equipment and components including pipes, flanges, seals, valves, pumps and compressors. This proposal allows for optical gas imaging (OGI) or EPA Method 21 as pre-approved methods for leak detection. In addition, the proposal allows for alternative techniques for leak detection which may be submitted to the Department for approval. Alternatives must be at least as effective as OGI or Method 21 in identifying leaks. The Department is also proposing an option to reduce the frequency of LDAR if an approved alternative method which offers continuous monitoring is utilized. A study focused on leak detection found that, in 31% of the cases, emissions concentrations either stayed within the same range or increased after leak repairs.[23] Therefore, the Department also proposes monitoring after leaks are repaired to ensure that leaks are successfully fixed.

Vapor Collection Systems: Vapor collection is the process of collecting vapors from storage vessels so that they are not released into the atmosphere. Collected vapors may be sent to the sales gas system or the fuel gas system. If these options are not available, then the collected vapors must be routed to an existing or new vapor collection system that must achieve at least ninety-five percent

[23] Carbon Limits, Statistical Analysis of Leak Detection and Repair in Europe, November 2017.

vapor control efficiency. Under this proposal, vapor collection systems will also be subject to LDAR requirements.

Data Collection: The proposal requires each source to submit a list of the components that are located at its site to the Department. This will allow the Department to better understand component emissions and where regulation may or may not be needed in the future.

Blowdowns: The proposal requires reporting of both planned and unplanned blowdowns of natural gas greater than ten thousand feet cubed.

This proposal impacts the transmission of natural gas to end users and the Department recognizes the importance of assuring that residents receive this fuel to heat homes in the winter. In addition, it is imperative that electricity generating sources receive this fuel to ensure that the grid continues to operate reliably. As a result, the Department has included feasibility and safety provisions in the proposal to ensure that fuel resources are available as needed for heat and electricity reliability.

Emissions Reductions

Storage Vessels: The Department calculated the Barrels of Oil Equivalent (BOE) for each of the producing wells in New York State based on 2018 data.[24] The Department compared the calculated BOE against EPA's table 4.2 from the 2016 CTG. Table 4.2 demonstrates a correlation

[24] DEC "Annual Well Production Search" www.dec.ny.gov.

between BOE and VOC emissions in tons per year. Based on this correlation the Department has determined that very few wells may have storage vessels that would trigger the threshold for the proposed vapor recovery requirement. Furthermore, the natural gas that is extracted in New York State is generally defined as "dry" and "sweet" which means that it requires very little, if any, processing before it enters the transmission pipeline. If vapor recovery is required for an applicable storage vessel it is estimated that each uncontrolled storage vessel emitting at 2 tpy over the threshold of 6 tpy of VOC will result in 6,223 $MTCH_4$ per year reduction (155,575 $MTCO_2e$ – 100 year GWP) (522,732 $MTCO_2e$ – 20 year GWP).[25] While the Department does not believe there are many storage vessels that exceed this threshold, if an assumption is made that ten to fifty percent of active wells have storage vessels that exceed the threshold, then New York can expect CH_4 emission reductions between 6,309 and 31,545 $MTCH_4$ (157,725 and 788,625 $MTCO_2e$ – 100 year GWP)(529,956 and 2,649,780 $MTCO_2e$ – 20 yr GWP) and potential corresponding VOC reductions of 1,009 to 5,047 tons.

Reciprocating compressors: The Department permits 77 reciprocating compressors within New York State. EPA's NSPS OOOO proposal estimated that individual compressor reductions through adherence to the proposed requirements would result in 9.2 tpy of CH_4 reduced per reciprocating compressor. Based on these estimates the proposed requirements would result in CH_4 reductions of 708 $MTCH_4$ (17,700 $MTCO_2e$ – 100 year GWP)(59,472 $MTCO_2e$ – 20 year GWP) and a corresponding reduction of 113 tons of VOC.

[25] Derived from EPA CTG 2016, Table 4-4.

Centrifugal Compressors: The Department permits 40 centrifugal compressors within New York State. Based on outreach and permit analysis, the Department believes that most of the permitted centrifugal compressors are dry seal but has not been able to confirm that all of them are. If any centrifugal compressors are wet seal, they will have the option to comply with the proposal by converting to dry seal or through the addition or use of a control system. Converting to dry seal is more costly than the installation of a control system so the Department expects that if a source is wet seals, it would use the less costly control system option. Based on the ICF 2014 study, the average CH_4 emissions from centrifugal compressor wet seal degassing are 63 scfm of natural gas per compressor. Assuming 8,000 hours of operation per year, the installation of controls would capture approximately 30 MMcf of natural gas per compressor or 791 $MTCH_4$ (66,444 $MTCO_2e$ – 20 yr GWP)(19,775 $MTCO_2e$ – 100 yr GWP) per compressor.[26] If an assumption is made that between ten and fifty percent of centrifugal compressors are dry seal, then the emission reductions would total between 3,164 and 15,819 $MTCH_4$ (265,776 and 1,328,796 $MTCO_2e$ – 20 year GWP) (79,100 and 395,475 MTCO2e – 100 yr GWP) per year and between 506 to 2,531 tons of VOC.

LDAR: A 2016 study determined a three-year fugitive emissions reduction from quarterly LDAR to be 78 percent.[27] EPA and ICF International both conservatively estimate emissions reductions from LDAR at 60 percent. New York's 2017 Greenhouse Gas Inventory[28] show CH_4 emissions of 14,874 $MTCH_4$ (371,850 $MTCO_2e$ – 100 year GWP)(1,249,416 MTCO2e – 20 year GWP) and 2,379 tons of VOC from wells. Since New York's pneumatic devices are rarely continuous

[26] ICF, 2014, Table 3-4.
[27] ICF International. *Leak Detection and Repair Cost-Effectiveness Analysis.* Revised May 2, 2016. Using data from subpart W, EPA/GRI, City of Fort Worth Natural Gas Air Quality Study, UT Study – Methane Emissions in the Natural Gas Supply Chain Production.
[28] New York State Energy Research and Development Authority (NYSERDA). 2019. "New York State Oil and Gas Sector Methane Emissions Inventory." NYSERDA Report Number 19-36. Prepared by Abt Associates, Rockville, MD and Energy and Environmental Research Associates, LLC, Pittsford, NY. nyserda.ny.gov/publications.

bleed and since it is unknown what assumption was used to account for tanks located at wells, a conservative assumption that one half of these emissions are fugitive would result in emissions reductions of 4,462 $MTCH_4$ (111,550 $MTCO_2e$ – 100 year GWP) (374,808 $MTCO_2e$ – 20 year GWP) and 714 tons of VOC per year from LDAR.

Table 2: Summary of potential reductions

	Metric tons (MT) CH4	MTCO2e (100 yr GWP)	MTCO2e (20 yr GWP)	Tons of VOC
Storage Vessels	6,309-31,545	157,725 - 788,625	529,956 – 2,649,780	1,009-5,047
Reciprocating Compressors	708	17,700	59,472	113
Centrifugal Compressors	3,164 – 15,819	79,100-395,475	265,776 – 1,328,796	506-2,531
LDAR	4,462	111,550	374,808	714
Total Emissions Reductions	14,643-52,534	366,075-1,313,350	1,230,012 – 4,412,856	2,343-8,405
2017 NYS Oil/Gas CH4 Emissions	106,561	2,664,182	8,951,124	
% Emissions Reductions within Sector	13% - 49%			

Costs

For the cost analysis the Department relied on a comprehensive analysis by ICF International and the Environmental Defense Fund (EDF) and EPA’s CTG for the Oil and Natural Gas Industry.

Storage Vessels: The proposal requires controls for storage vessels which have a PTE greater than 6 tpy of VOCs. It is not expected that there are many, if any, storage vessels within New York that will be above the threshold, however, the Department included this requirement in the proposal to ensure that all storage vessels are reviewed and that those that exceed the threshold are controlled. The 2016 EPA CTG lists capital costs to install vapor recovery at $171,538 and annual costs at $28,230.

Table 3: Capital Investments and Annual Costs of Vapor Recovery for Storage Vessels[29]	
Item	**Cost ($2012)**
Capital Costs	
Vapor Recovery Unit (VRU)[a]	$90,000
Freight and Design[a]	$1,648
VRU Installation[a]	$11,154
Storage Vessel Retrofit[b]	$68,736
Total Capital Investment	$171,538
Annual Costs	
Maintenance ($/yr)	$9,396
Capital Recovery (7 percent interest, 15-year equipment life) ($/yr)	$18,834
Total Annual Costs w/o Savings ($/yr)	$28,230
[a] Economic Impact Analysis Colorado Air Quality Control Commission.	
[b] Assumes storage vessel retrofit is 75 percent of the purchased equipment price, assumptions from Exhibit 6 of the EPA Natural Gas Star Lessons Learned, Installing Vapor Recovery Units on Storage Tanks, October 2006.	

If the recovered vapor cannot be reintroduced into the fuel gas system or sales gas system, then an additional process must be added to reduce emissions. Typically, combustion of the vapor is considered here. EPA estimates the capital and annual costs in Table 4.

Table 4: Capital Investments and Annual Costs of Vapor Recovery leading to Combustion[30]	
Item	**Cost ($2012)**
Capital Costs	
Combustor[a]	$18,169
Freight and Design[a]	$1,648

[29] EPA CTG 2016, Table 4-3.
[30] EPA Control Techniques Guidelines for the Oil and Natural Gas Sector, 2016.

Auto Igniter[a]	$1,648
Surveillance System[b,c,d]	$3,805
Combustor Installation[a]	$6,980
Storage Vessel Retrofit[e]	$68,736
Total Capital Investment	$100,986
Annual Costs	
Operating Labor[f]	$5,155
Maintenance Labor[f]	$4,160
Non-Labor Maintenance[a]	$2,197
Pilot Fuel	$1,537
Data Management[c]	$1,057
Capital Recovery (7 percent interest, 15-year equipment life) ($/yr)	$11,088
Total Annual Costs w/o Savings ($/yr)	$25,194
[a] Economic Impact Analysis Colorado Air Quality Control Commission.	
[b] Surveillance system identifies when pilot is not lit and attempts to relight it, documents the duration of time when the pilot is not lit, and notifies the operator that repairs are necessary.	
[c]EPA Oil and Natural Gas Sector: Standards of Performance for Crude Oil and natural Gas Production, Transmission and Distribution – Background Supplemental Technical Support Document for the Final New Source Performance Standards. (2012 TSD).	
[d]Cost established from 2012 TSD and escalated using the change in GDP: Implicit Deflator from 2008 to 2012. FRED GRP.	
[e]Operating labor includes technical operation of device at 130 hr/yr and supervisory labor at 15% of technical labor. Maintenance labor hours are assumed to be the same as operatory labor at 130 hr/yr. Labor rates are $32/hr for technical and maintenance and 51.03/hr for supervisory and were obtained from the U.S. Department of Labor, Bureau of Labor Statistics.	

Compressors – Reciprocating: Gas Science to Achieve Results (STAR) data results show that rings (the compressor packing) cost between $300 and $600 per cylinder and $1,000 to $2,500 per compressor to install.[31] Assuming $2,500 per compressor, the cost to change the rod packing for all 77 permitted reciprocating compressors is $192,500 for each 26,000 hours of operation. Based on

[31] EPA Gas Star program, "Reducing Methane Emissions From Compressor Rod Packing Systems" https://www.epa.gov/sites/production/files/2016-06/documents/ll_rodpack.pdf.

typical operation, EPA estimates the cost to be $2,153 per compressor per year[32] which translates into $165,781 per year for all 77 reciprocating compressors.

Compressors – Wet Seal Centrifugal: This proposal allows for two compliance mechanisms for high emitting wet-seal centrifugal compressors; convert to dry-seal or capture the gas. The 2014 EDF report estimated that converting a wet-seal system to a dry-seal system costs approximately $300,000 and would likely not be the choice for most impacted sources even though the EPA Gas Star program estimated that the cost of conversion would pay for itself within a year with natural gas savings.[33] The other option, to capture the natural gas, is less costly and savings may be realized by generating additional gas sales if the natural gas is rerouted to the compressor inlet, or if the recovered gas is used for site fuel. The capital cost to retrofit a gas capture system is estimated in the EDF 2014 report at $50,000 for a 95% reduction of natural gas loss. A survey of the 40 centrifugal compressors permitted in New York indicate that most already have a dry seal, so the Department does not expect high costs associated with this requirement.

Leak Detection and Repair: This proposal requires LDAR at well sites (semiannually), gathering and boosting sources (quarterly), transmission compressor stations (bimonthly), storage facilities (bimonthly), and the City Gate (quarterly).

The capital cost for semiannual LDAR at well sites is estimated at $801 for up to 22 wells to develop an LDAR plan. Annual costs for LDAR personnel or consultants and repairs are estimated at $2,285, ICF estimated this cost to be $2,006.[34] There are 3,411 producing oil wells and 6,729

[32] EPA 2016 CTG, Table 5-5.
[33] EPA Gas Star program, https://www.epa.gov/sites/production/files/2016-06/documents/ll_wetseals.pdf.
[34] ICF, 2014, Table 3-4.

producing natural gas wells in New York. Assuming groupings of 22 wells, the initial capital cost for LDAR is $369,261 and the recurring annual cost is estimated at between $924,766 and $1,053,385.

EPA estimates a capital cost for semiannual LDAR at gathering and boosting stations of $2,393 and annual costs at $13,534.[35] However, EDF estimates an annual cost of $6,017 for quarterly LDAR, for gathering and boosting stations and transmission compressor stations.[36] To account for the costs of performing bimonthly LDAR, quarterly LDAR costs are multiplied by 1.5 (50% increase), resulting in an annual cost estimate of $9,025.5 (EDF) or $20,301 (EPA). There are 32 compressor stations permitted in New York with 117 compressors. Based on this information, the range of annual costs for LDAR at these compressor stations is between $288,816 and $649,632.

Table 5: Summary of Potential Costs

	Quantity	Initial Cost Low	Initial Cost High	Annual Cost Low	Annual Cost High
Storage Vessels vapor recovery	10% - 50%	34,787,906	173,939,532	5,725,044	28,625,220
Compressor - recip	All compressors			165,781	165,781
Compressor - centrifugal	10% - 50%	200,000	1,000,000		
LDAR - wells	All wells	369,261	369,261	924,766	1,053,385
LDAR - compressors	All compressors			288,816	649,632
TOTAL		35,357,167	175,308,793	7,104,407	30,494,018

Estimated costs are summarized in Table 5 and demonstrate that a large portion, over eighty percent, of the costs fall into the potential for storage vessel vapor recovery. This is also the category where the Department is uncertain if any vessels will be required to install these controls. The Department made the assumptions that ten to fifty percent of applicable vessels would need to install

[35] EPA CTG, 2016, Table 9-26.
[36] ICF, 2014, Table 3-4.

controls and that groupings of 5 wells shared a storage vessel. After storage vessels are assessed, it may result that very few, if any, will actually trigger the requirement to install vapor recovery which would eliminate over eighty percent of these costs.

These potential costs are associated with the New York natural gas market which according to the United States Energy Information Administration (EIA) reported natural gas consumption of 1,312,031 million cubic feet. EIA also reports a price at the Citygate of $4.25 per thousand cubic feet.[37] Extrapolating from this data indicates that over 5.5 billion dollars passed through this market in 2019.

Cost of Emitting Methane

The Department agrees with EPA's previously accepted conclusion of the Interagency Working Group on Social Cost of Greenhouse Gases (IWG) that GHG emissions are a global externality that damage the entire world, not just the United States, and therefore the only appropriate figure to use is the full global social cost of carbon when calculating the damages.[38] The social cost of CH_4, when valued in line with the IWG, is $1,100 (2007 dollars) per metric ton.[39] The Department recently [proposed/finalized] its Value of Carbon guidance, as required under the CLCPA. ECL § 75-0113. This guidance includes updated values for the social cost of methane, valued in line with the IWG and using various discount rates. Under the DEC's Value of Carbon guidance, the social cost of methane

[37] EIA Natural Gas Summary, 2019. https://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_SNY_a.htm.
[38] IPCC Special Report on Global Warming of 1.5*C (SRIS) http://www.ipcc.ch/report/srIS/. See summary for Policy makers.
[39] Marten & Newbold, 2011 Working Paper, Estimating the Social Costs of Non-CO2 GHG Emissions: Methane and Nitrous Oxide.

in 2020 ranges from $1,527 per metric ton at a three percent discount rate, to $6,578 per metric ton at a one percent discount rate, with a central value of $2,782 per metric ton at the 2% discount rate.

Using the estimated emissions reductions calculated (Table 2), Table 6 shows the cost of the missed opportunity to reduce these emissions. Put another way, Table 5 shows the value of the benefits of reducing this amount of methane emissions. It is important to note that not all potential emission reductions have been calculated as data does not exist on the amount of reductions. For example, this proposal requires LDAR at the Citygate which does not have an estimated reduction factor.

Table 6			
Annual Cost of Methane			
Total Potential Emissions Reductions ($MTCH_4$)	14,643 – 52,534		
Social Cost if Reductions are not achieved[40] (2020 dollars)	$96,321,654 - $345,568,652	$40,736,826 - $146,149,588	$22,359,861 - $80,219,418
	1% Discount Rate ($6,578/ metric ton)	**2% Discount Rate ($2,782/ metric ton)**	**3% Discount Rate ($1,527/ metric ton)**

Comparing Tables 5 and 6 demonstrates that the cost of reducing emissions from these sources is significantly less than the value achieved by the reductions.

Cost of emitting VOC's

[40] NYSDEC Cost of Carbon Guidance

There is a cost associated with emitting VOC's resulting in the formation of ground level ozone. This proposal is part of a suite of New York State efforts to bring the NYMA into attainment for ozone, in order to adequately protect human health and welfare. In the Regulatory Impact Analysis (RIA) for the 2015 ozone NAAQS, EPA projected a wide array of benefits that would be realized on a national level, excluding California, if ozone attainment is achieved. This includes co-benefits from reduced $PM_{2.5}$ which both EPA and DEC include because $PM_{2.5}$ is reduced automatically with NOx controls and there is no additional cost for these reductions. According to the U.S. Census Bureau, New York's nonattainment county population accounts for 14 percent of total United States population[41] excluding California. On a population basis, the benefits to New York State are the prevention of the following annually:

Table 7	
Attainment Provides Prevention of:	
Deaths from effects of ozone	13 - 22
Deaths from effects of PM2.5	31 - 70
Nonfatal heart attacks	4 - 36
Hospital admissions & emergency room visits	134
Acute bronchitis events	48
Upper & lower respiratory symptom events	1,540
Exacerbated asthma events	32,200
Missed work & school days	26,320
Restricted activity days	86,800

Table 7: Summary of Total Number of Annual Ozone and PM-Related Premature Mortalities and Premature Morbidity: 2025 National Benefits (adapted from EPA, 2015 RIA, p. ES-16).

Table 7, which represents a simple population based conservative estimate, demonstrates that there is a serious cost of nonattainment to New York State residents. The NYMA experiences some

[41] U.S. Census Bureau, "State Population Totals and Components of Change: 2010-2017." https://www.census.gov/data/tables/2017/demo/popest/state-total.html.

of the highest ozone levels in the nation outside of California and will greatly benefit from lowered ozone levels.

Impact on Jobs

New York State Department of Labor (NYSDOL) lists employment in New York State by standard occupational classification (SOC) codes. The SOC code for extraction in the oil and natural gas industry is 47-5000. According to NYSDOL data, there are 2,280 jobs with this SOC code in New York State.

The Department relied on a larger assessment conducted by the California Air Resources Board (CARB) to evaluate economic impacts of an oil and natural gas regulation. CARB used a computational general equilibrium model called the Regional Economic Models, Inc. (REMI). The REMI model generates year-by-year estimates of the total regional effects of a policy or set of policies. CARB used the REMI Policy Insight (REMI PI+) model for their analysis.[42]

Based on that analysis, CARB determined that its regulation would have a very small impact on employment growth each year. Their results show the initial small increase in employment growth primarily due to the increased demand for capital and components for secondary industries and increases in other employment due to the induced and indirect effects of the regulation. After that initial small increase, employment is expected to go back to baseline and perhaps decline.[43]

[42] CARB Regulation for Reduction of Greenhouse Gas Emissions from Crude Oil and Natural Gas Operations, Standardized Regulatory Impact Assessment.
[43] Table E-7, CARB Regulation for Reduction of Greenhouse Gas Emissions from Crude Oil and Natural Gas Operations, Standardized Regulatory Impact Assessment.

The Department believes that in New York there will also be an initial slight increase in jobs due to the need for services like leak detection and repair (LDAR) and reporting requirements. After the initial increase, there will still be a need for LDAR staffing and it is expected that those jobs will remain, not decrease.

Costs to the Department and State

The authority and responsibility for implementing Part 203 lies solely with the Department. Each subject source with a Title V facility permit under 6 NYCRR Subpart 201-6 or State Facility Permit under 6 NYCRR Part 201-5 will require permit revisions to account for the requirements of Part 203 and the revised permit conditions will be incorporated into each relevant permit by DEC staff.

Each subject source will need to submit component data. The Department must review and determine the sufficiency of all the reports that will be submitted by the source owner. The review of the initial reporting will require DEC staff time. It is estimated that this rulemaking and ongoing support will require 1.5 full time equivalent (FTE) or $237,500[44] during the first year and 1 to 3 FTE annually thereafter to implement and enforce.

This proposal may also impact other Departments such as the Department of Public Service (DPS) and will likely result in additional workload for that agency. It is unknown exactly how many

[44] Assumptions: Grade 24 pay rate of $97,448 per year and an overhead rate of 62.48 percent. Per: https://www.osc.state.ny.us/agencies/guide/MyWebHelp/#VII/9/9.htm.

FTE's will be required to support any requests for rate cases from the impacted sources or other additional workload that may result from this proposal.

Potential costs to rate payers

Impacted gas utilities may submit rate cases to DPS which could result in increased rates for natural gas to end use customers. It is unknown if an increase would be approved or, if approved, how much of an increase would be expected.

Local government mandates

The proposed regulation does not impose a mandate on local governments. Local governments have no additional compliance obligations as compared to other subject entities.

It is worth noting that the Department has been contacted by several local governments including Towns of Lewisboro, North Salem, Southeast, Somers, & Bedford, the City of White Plains, and Westchester County asking the Department to reduce emissions from compressor stations and from the natural gas sector generally.

Paperwork

In general, this proposal requires impacted sources to maintain records for five years and submit records within 60 days of certain events and annually for maintenance.

More specifically, reciprocating natural gas and centrifugal compressors must maintain, for at least five years:

- from the date of each leak concentration measurement, a record of each rod packing leak concentration measurement found above the minimum leak threshold.
- from the date of each emissions flow rate measurement, a record of each rod packing emission flow rate measurement.
- a record that documents the date(s) and hours of operation a compressor is operated in order to demonstrate compliance with the rod packing leak concentration or emission flow rate measurement in the event that the compressor is not operating during a scheduled inspection (reciprocating compressors only).
- records that provide proof that parts or equipment required to make necessary repairs have been ordered.

Natural Gas actuated Pneumatic Devices must maintain, for at least five years from the date of each emissions flow rate measurement, a record of the emission flow rate measurement.

LDAR records must be maintained for at least five years:

- from each inspection, a record of each leak detection and repair inspection.
- the date of each inspection, component leak and repair documentation.
- proof that parts or equipment required to make necessary repairs have been ordered.
- gas service utility records that demonstrate that a system has been temporarily classified as critical to reliable public gas operation throughout the duration of the classification period.

Vapor Collection System and Vapor Control Devices must maintain records for at least five years that provide proof that parts or equipment required to make necessary repairs have been ordered and installed.

In addition to the regular paperwork described above, the proposal requires documentation of:

- Planned and unplanned blowdowns
- Pigging activities

Furthermore, all impacted sources are required to submit a component inventory in the first year after adoption or, for future sources, the first year that a source begins activity. This inventory will only need to be submitted once unless equipment is changed or added.

Other State Programs

The Department worked with DPS to ensure that there was consistency in the terminology and that there was no duplication in requirements between their requirements and what is being proposed here. Some affected sources are required to report to other entities, but the Department does not anticipate that the proposal results in any duplication in reporting.

Within the Department, the Division of Mineral Resources (DMN) has historically regulated well operators. Since this proposal is to regulate emissions at well sites the Division of Air Resources has worked with DMN to ensure there is no duplication of requirements or paperwork. The Divisions took steps to ensure that the initial inventory submittal in this proposal corresponds with the annual well report requirement so that the impacted sources will only have to reply to one request.

Alternatives

Alternative #1 – No Action: If the Department chooses to not act, this will constitute a violation of the Clean Air Act. EPA's publication of the CTG requires that New York develop a regulation for this sector that is at least as a stringent as the requirements of the CTG. Furthermore, the Department believes that the reductions resulting from this proposal are beneficial to the health and welfare of New Yorkers. The Department did not choose this option.

Alternative #2 – Include Required Continuous Emission Monitoring at all sites: The Department considered the requirement of continuous emissions monitoring at all oil and natural gas sources to continuously monitor for CH_4. At the time of the development of this proposal, the Department does not believe that the technology is readily available to support this requirement. However, the Department did add this option as an alternative technology because it anticipates this technology to become more readily available in the coming years.

Alternative #3 – Remove LDAR requirements: The Department understands that LDAR is a technology that some in the oil and natural gas sector are not familiar with and as a result researched the implications of removing these requirements. The research clearly demonstrated that significant reductions are achieved through LDAR and because of this the Department chose to keep the LDAR requirements.

Federal standards

The EPA has a NSPS which places requirements on this sector. The NSPS has been subject to stays and rollbacks and has created uncertainty with regulators and the regulated community. In addition, EPA published a CTG which requires the Department to develop a regulation for existing sources for VOCs only. This proposal satisfies the CTG requirement while addressing the State's commitment to reduce GHG emissions under the CLCPA. In addition to satisfying certain Federal requirements and seeking GHG emission reductions, this proposed regulation aims to achieve VOC reductions that are necessary to achieve ozone NAAQS attainment. Furthermore, this regulation is protective of public health and the environment in an area where Federal regulations are uncertain.

Compliance schedule

The Department is proposing an initial compliance date of January 1, 2023 so that the industry has time to comply with the requirements of the proposed regulation. The first report forms must be submitted by March 31, 2023.

6 NYCRR Part 203, Oil and Natural Gas Sector

6 NYCRR Part 200, General Provisions

Job Impact Statement

The New York State Department of Environmental Conservation (DEC or Department) is proposing new 6 NYCRR Part 203, “Oil and Natural Gas Sector” and Part 200 and attendant revisions to 6 NYCRR Part 200, “General Provisions.” (collectively, Part 203). The primary need for this rulemaking is to protect the health and welfare of New York residents and resources by: 1) reducing methane (CH_4), a greenhouse gas, in support of the goals of the Climate Leadership and Community Protection Act (CLCPA), 2) reducing associated volatile organic compounds (VOCs), an ozone precursor, and 3) fulfilling the requirements of the United States Environmental Protection Agency’s (EPA) 2016 Control Techniques Guidelines (CTG) for the oil and gas industry.[1]

NATURE OF IMPACT

The Department relied on a larger assessment conducted by the California Air Resources Board (CARB) to evaluate economic impacts of an oil and natural gas regulation. CARB used a computational general equilibrium model called the Regional Economic Models, Inc. (REMI). The REMI model generates year-by-year estimates of the total regional effects of a policy or set of policies. CARB used the REMI Policy Insight (REMI PI+) model for their analysis.[2]

[1] 81 FR 74798 (October 27, 2016).

[2] CARB Regulation for Reduction of Greenhouse Gas Emissions from Crude Oil and Natural Gas Operations, Standardized Regulatory Impact Assessment.

Based on that analysis, CARB determined that their regulation would have a very small impact on employment growth each year. Their results show the initial small increase in employment growth primarily due to the increased demand for capital and components for secondary industries and increases in other employment due to the induced and indirect effects of the regulation. After that initial small increase, employment is expected to go back to baseline and perhaps reduce.[3]

The Department believes that in New York there will also be an initial slight increase in jobs due to the need for services like leak detection and repair (LDAR) and reporting requirements. After the initial increase, there will still be a need for LDAR staffing and it is expected that those jobs will remain, not decrease.

CATEGORIES AND NUMBERS AFFECTED

There are 32 permitted compressor stations with a total of 117 permitted compressors in New York State. New York also has 27 underground natural gas storage sources. While the proposal establishes requirements for metering and regulating stations actual counts for these stations is not well-established. It has been estimated that there may be somewhere between 3,000 and 4,000 metering and regulating stations in New York. In 2018 there were 3,411 active oil wells and 6,729 active gas wells. In 2018, 10.6 billion cubic feet (bcf) of natural gas and 224,717 barrels (bbl) of oil were extracted in New York.

[3] Table E-7, CARB Regulation for Reduction of Greenhouse Gas Emissions from Crude Oil and Natural Gas Operations, Standardized Regulatory Impact Assessment.

New York State Department of Labor (NYSDOL) lists employment in New York State by standard occupational classification (SOC) codes. The SOC code for extraction in the oil and natural gas industry is 47-5000. According to NYSDOL data, there are 2,280 jobs with this SOC code in New York State.

REGIONS OF ADVERSE IMPACT

This is a statewide proposal and will apply throughout New York State. Most of the sources exist in western New York and the Southern Tier.   These are primarily well sites and natural gas storage sites. Compressor stations are located throughout the state.

MINIMIZING ADVERSE IMPACT

This proposal impacts natural gas transmission to end users and the Department recognizes the importance of assuring that residents receive this fuel to heat homes in the winter. In addition, it is imperative that electricity generating sources receive this fuel to ensure that the grid continues to operate reliably. As a result, the Department has included feasibility and safety provisions in the proposal to ensure that fuel resources are available as needed for heat and electricity reliability. Specifically, the proposal includes a Subpart (203-9) which allows for delays of required repairs if that repair is not safe or feasible by the Public Service Commission or other state or federal agency responsible for safety, feasibility or reliability.

SELF EMPLOYMENT OPPORTUNITIES

The Department anticipates that the requirements of Part 203 will result in new LDAR jobs which may materialize as self-employment opportunities or added positions in already established businesses.

INITIAL REVIEW

The initial review of this rule shall occur no later than in the third calendar year after the year in which the rule is adopted.

6 NYCRR Part 203, Oil and Natural Gas Sector

6 NYCRR Part 200, General Provisions

Rural Area Flexibility Analysis

The New York State Department of Environmental Conservation (DEC or Department) is proposing new 6 NYCRR Part 203, “Oil and Natural Gas Sector” and Part 200 and attendant revisions to 6 NYCRR Part 200, “General Provisions.” (collectively, Part 203). The primary need for this rulemaking is to protect the health and welfare of New York residents and resources by: 1) reducing methane (CH_4), a greenhouse gas, in support of the goals of the Climate Leadership and Community Protection Act (CLCPA), 2) reducing associated volatile organic compounds (VOCs), an ozone precursor, and 3) fulfilling the requirements of the United States Environmental Protection Agency’s (EPA) 2016 Control Techniques Guidelines (CTG) for the oil and gas industry.[1]

TYPES AND ESTIMATED NUMBERS OF RURAL AREAS AFFECTED

Most of the sources impacted by this proposal are located in rural areas in Western New York and the Southern Tier. There are 32 permitted compressor stations with a total of 117 permitted compressors located throughout New York State primarily in rural areas. New York also has 27 underground natural gas storage sources located primarily around the Finger Lakes region. While this proposal establishes requirements for metering and regulating stations actual counts for these stations are not well-established and the Department believes them to be located throughout the

[1] 81 FR 74798 (October 27, 2016).

state. It has been estimated that there may be somewhere between 3,000 and 4,000 metering and regulating stations in New York. In 2018 there were 3,411 active oil wells and 6,729 active gas wells that are primarily located in Western New York and the Southern Tier in rural areas.

REPORTING, RECORDKEEPING AND OTHER COMPLIANCE REQUIREMENTS; AND PROFESSIONAL SERVICES

Reporting & Recordkeeping:

In general, this proposal requires impacted sources to maintain records for five years and submit records to the Department within 60 days of certain events and annually for maintenance. These requirements apply to all applicable sources, whether they are located in rural areas or not.

More specifically, reciprocating natural gas and centrifugal compressors must maintain, for at least five years:

- from the date of each leak concentration measurement, a record of each rod packing leak concentration measurement found above the minimum leak threshold.
- from the date of each emissions flow rate measurement, a record of each rod packing emission flow rate measurement.
- a record that documents the date(s) and hours of operation a compressor is operated in order to demonstrate compliance with the rod packing leak concentration or emission flow rate measurement in the event that the compressor is not operating during a scheduled inspection (reciprocating compressors only).

- records that provide proof that parts or equipment required to make necessary repairs have been ordered and installed.

Natural Gas actuated Pneumatic Devices must maintain, for at least five years from the date of each emissions flow rate measurement, a record of the emission flow rate measurement.

Leak Detection and Repair records must be maintained for at least five years:

- from each inspection, a record of each leak detection and repair inspection.
- the date of each inspection, component leak and repair documentation.
- proof that parts or equipment required to make necessary repairs have been ordered and installed.
- gas service utility records that demonstrate that a system has been temporarily classified as critical to reliable public gas operation throughout the duration of the classification period.

Vapor Collection System and Vapor Control Devices must maintain records for at least five years that provide proof that parts or equipment required to make necessary repairs have been ordered and installed.

In addition to the regular paperwork described above, the proposal requires all impacted sources to submit a component inventory by March 31, 2023 or, for future sources, by March 31st immediately following the first year that a source begins activity. This inventory will only need to be submitted once unless equipment is changed or added.

Compliance Requirements:

Impacted sources are required to submit a component inventory to the Department. This is expected to be submitted by March 31, 2023. Beginning January 1, 2023, impacted sources are required to complete leak detection and repair (LDAR) on equipment either bi-annually or quarterly. Reciprocating compressors are required to change the rod packing on the equipment every 26,000 hours of operation. Centrifugal compressors with wet seals are required to either convert to dry seal or to capture vented natural gas for reuse or destruction. Storage vessels with a potential to emit greater than six tons per year of VOCs must capture those emissions with an efficiency of ninety-five percent. If a blowdown occurs and is greater than ten thousand cubic feet, then it must be reported ahead of the blowdown if planned and within thirty minutes, or as soon as safely feasible, for an unplanned blowdown.

Professional Services:

Professional services likely to be needed to meet the requirements of this proposal are primarily LDAR services and services associated with vapor control and recovery.

COSTS

While most of the sources are located in rural areas, the costs are spread throughout the state and do not apply only to rural sectors. The nature of this industry is that the production of natural gas and oil and transmission of natural gas are located in mostly rural areas, the end product is found throughout the state.

Storage Vessels: The proposal requires controls for storage vessels which have a potential to emit (PTE) greater than 6 tpy of VOCs. It is not expected that there are many, if any, storage vessels within New York that will be above the threshold, however, the Department included this requirement in the proposal to ensure that all storage vessels are reviewed and that those that exceed the threshold are controlled. The 2016 EPA CTG lists capital costs to install vapor recovery at $171,538 and annual costs at $28,230.

Compressors – Reciprocating: Gas Science to Achieve Results (STAR) data results show that rings (the compressor packing) cost between $300 and $600 per cylinder and $1,000 to $2,500 per compressor to install.[2] Assuming $2,500 per compressor, the cost to change the rod packing for all 77 permitted reciprocating compressors is $192,500 for each 26,000 hours of operation. Based on typical operation, EPA estimates the cost to be $2,153 per compressor per year[3] which translates into $165,781 per year for all 77 reciprocating compressors.

Compressors – Wet Seal Centrifugal: This proposal allows for two compliance mechanisms for high emitting wet seal centrifugal compressors; convert to dry seal or capture the gas. The 2014 Environmental Defense Fund (EDF) report estimated that converting a wet seal system to a dry seal system costs approximately $300,000 and would likely not be the choice for most impacted sources even though the EPA Gas STAR program estimated that the cost of conversion would pay for itself within a year with natural gas savings.[4] The other option, to capture the natural gas, is less costly and savings may be realized by generating additional gas sales if the natural gas is rerouted to the compressor inlet, or if the recovered gas is used for site fuel. The capital cost to retrofit a gas capture

---

[2] EPA Gas Star program, "Reducing Methane Emissions From Compressor Rod Packing Systems" https://www.epa.gov/sites/production/files/2016-06/documents/ll_rodpack.pdf.

[3] EPA 2016 CTG, Table 5-5.

[4] EPA Gas Star program, https://www.epa.gov/sites/production/files/2016-06/documents/ll_wetseals.pdf.

system is estimated in the EDF 2014 report at $50,000 for a 95% reduction of natural gas loss. A survey of the 40 centrifugal compressors permitted in New York indicates that most already have a dry seal, so the Department does not expect high costs associated with this requirement.

Leak Detection and Repair: This proposal requires LDAR at well sites (semiannually), gathering and boosting sources (quarterly), transmission compressor stations (bimonthly), storage facilities (bimonthly), and the Citygate (quarterly).

The capital cost for semiannual LDAR at well sites is estimated at $801 for up to 22 wells to develop an LDAR plan. Annual costs for LDAR personnel or consultants and repairs are estimated at $2,285, ICF estimated this cost to be $2,006.[5] There are 3,411 producing oil wells and 6,729 producing natural gas wells in New York. Assuming groupings of 22 wells, the initial capital cost for LDAR is $369,261 and the recurring annual cost is estimated at between $924,766 and $1,053,385.

EPA estimates a capital cost for semiannual LDAR at gathering and boosting stations of $2,393 and annual costs at $13,534.[6] However, EDF estimates an annual cost of $6,017 for quarterly LDAR, for gathering and boosting stations and transmission compressor stations.[7] To account for the costs of performing bimonthly LDAR, quarterly LDAR costs are multiplied by 1.5 (50% increase), resulting in an annual cost estimate of $9025.5 (EDF) or $20,301 (EPA). There are 32 compressor stations permitted in New York with 117 compressors. Based on this information, the range of annual costs for LDAR at these compressor stations is between $288,816 and $649,632.

---

[5] ICF, 2014, Table 3-4.
[6] EPA CTG, 2016, Table 9-26.
[7] ICF, 2014, Table 3-4.

There is also a cost to the Department. Each subject source will need to submit component data. The Department must review and determine the sufficiency of all the reports that will be submitted by the source owner. The review of the initial reporting will require DEC staff time. It is estimated that this rulemaking and ongoing support will require 1.5 full time equivalent (FTE) or $237,500[8] during the first year and 1.0 FTE annually thereafter.

This proposal may also impact other Departments such as the Department of Public Service (DPS) and will likely result in additional workload for that Agency. It is unknown exactly how many FTE's will be required to support any requests for rate cases from the impacted sources or other additional workload that may result from this proposal.

MINIMIZING ADVERSE IMPACT

The smaller rural sources are primarily natural gas and oil wells. Larger compressor stations are accustomed to regulation by the Department. To minimize adverse impact the Department met with the Independent Oil and Gas Association of New York (IOGA-NY) to develop the best method to ask for information from that community. The proposal also provides alternative compliance methods, upon approval by the Department, for alternative LDAR techniques in anticipation of alternative, lower cost, techniques becoming available.

RURAL AREA PARTICIPATION

[8] Assumptions: Grade 24 pay rate of $97,448 per year and an overhead rate of 62.48 percent. Per: https://www.osc.state.ny.us/agencies/guide/MyWebHelp/#VII/9/9.htm.

The Department met with IOGA-NY three times and presented at the IOGA-NY annual meeting twice prior to the proposal of this regulation to allow rural participation. In addition, the Department posted a stakeholder outline on the DEC website to encourage stakeholder participation and comment.[9]

INITIAL REVIEW

The initial review of this rule shall occur no later than in the third calendar year after the year in which the rule is adopted.

[9] https://www.dec.ny.gov/chemical/113887.html.

6 NYCRR Part 203, Oil and Natural Gas Sector

6 NYCRR Part 200, General Provisions

Revised Regulatory Flexibility Analysis for Small Businesses and Local Governments

The New York State Department of Environmental Conservation (DEC or Department) is proposing new 6 NYCRR Part 203, “Oil and Natural Gas Sector” and Part 200 and attendant revisions to 6 NYCRR Part 200, “General Provisions.” (collectively, Part 203). The primary need for this rulemaking is to protect the health and welfare of New York residents and resources by: 1) reducing methane (CH_4), a greenhouse gas, in support of the goals of the Climate Leadership and Community Protection Act (CLCPA), 2) reducing associated volatile organic compounds (VOCs), an ozone precursor, and 3) fulfilling the requirements of the United States Environmental Protection Agency’s (EPA) 2016 Control Techniques Guidelines (CTG) for the oil and gas industry.[1]

EFFECT OF RULE

The types of small businesses that are impacted by this proposal are the operators and owners of wells and leak detection and repair (LDAR) companies. The Department is aware that some local governments operate and use wells and they will also be impacted. Well owners and operators will be subject to regulation that they have not been subject to in the past and will incur additional expenses due to the LDAR requirements. LDAR companies will likely see an increase in business due to the additional LDAR requirements in this proposal. In 2018 there were 3,411 active

[1] 81 FR 74798 (October 27, 2016).

oil wells and 6,729 active gas wells in New York State. In 2018, 10.6 billion cubic feet (bcf) of natural gas and 224,717 barrels (bbl) of oil were extracted from New York's wells.

COMPLIANCE REQUIREMENTS

Oil and gas well sites in New York are simpler configurations than those found in other regions of the United States because most of the natural gas extracted in New York is very dry. This dry gas does not have to be processed to the extent required in other regions before it can enter a natural gas transmission pipeline. Therefore, natural gas extraction in New York State does not require the level of storage vessels or tanks that are found in other natural gas extraction regions around the country. However, there may be storage vessels, or tanks, at well sites which may contain produced water, separation products or other fluids. These storage vessels may emit VOCs and CH_4. If a VOC potential to emit (PTE) threshold of 6 tpy is exceeded, storage vessels at well sites are required to install a vapor recovery system which is subject to LDAR requirements. A finished and producing natural gas well will also include flow lines and gathering lines and may include heater separators. Pneumatic devices may be used for maintaining process conditions. The wellhead, piping, heater separators and pneumatic devices will all be subject to the LDAR requirements in the proposal.

In general, this proposal requires impacted sources to maintain records for five years and submit records within 60 days of certain events.

Natural Gas actuated Pneumatic Devices must maintain, for at least five years from the date of each emissions flow rate measurement, a record of the emission flow rate measurement.

Leak Detection and Repair records must be maintained for at least five years:

- from each inspection, a record of each leak detection and repair inspection.
- the date of each inspection, component leak and repair documentation.
- that provide proof that parts or equipment required to make necessary repairs have been ordered and installed.
- gas service utility records that demonstrate that a system has been temporarily classified as critical to reliable public gas operation throughout the duration of the classification period.

Vapor Collection System and Vapor Control Devices must maintain records for at least five years that provide proof that parts or equipment required to make necessary repairs have been ordered and installed.

In addition to the regular paperwork described above, the proposal requires all impacted sources to submit a component inventory in the first year of adoption or, for future sources, the first year that a source begins activity. This inventory will only need to be submitted once unless equipment is changed or added.

PROFESSIONAL SERVICES

The Department expects that well owners and operators are likely to hire professional service providers to comply with the LDAR requirements of this proposal.

COMPLIANCE COSTS

Storage Vessels: The proposal requires controls for storage vessels which have a PTE greater than 6 tpy of VOCs. It is not expected that there are many, if any, storage vessels within New York that will be above the threshold, however, the Department included this requirement in the proposal to ensure that all storage vessels are reviewed and that those that exceed the threshold are controlled. The 2016 EPA CTG lists capital costs to install vapor recovery at $171,538 and annual costs at $28,230.

Leak Detection and Repair: This proposal requires LDAR at well sites (semiannually). The capital cost for semiannual LDAR at well sites is estimated at $801 for up to 22 wells to develop an LDAR plan. Annual costs for LDAR personnel or consultants and repairs are estimated at $2,285 by EPA, ICF estimated this cost to be $2,006.[5] There are 3,411 producing oil wells and 6,729 producing natural gas wells in New York. Assuming groupings of 22 wells, the initial capital cost for LDAR is $369,261 and the recurring annual cost is estimated at between $924,766 and $1,053,385.

ECONOMIC AND TECHNOLOGICAL FEASIBILITY

Current technology is available and feasible for owners and operators to use in order to comply with the proposed requirements of Part 203. The leak detection techniques within this proposal have been used in the industry for many years. In addition, new techniques are continuously under development which may offer a more affordable pathway to compliance in the future. The

Department included an alternative technology approval process in the proposal to accommodate changes over time.

This proposal imposes an economic burden on well owners and operators with the additional expense of LDAR and, if needed, vapor recovery on storage vessels. The result of repairing leaks of natural gas is recovery of the primary sales product of each well, so it is expected that a portion of added economic burden may be offset by commodity recovery. The Department expects those costs not offset by recover to be relayed to consumers through increased natural gas costs.

MINIMIZING ADVERSE IMPACTS

The Department is required to implement a regulation to address leaks at oil and natural gas wells as a result of the EPA published CTG, which provided minimum requirements for oil and gas wells. This proposal satisfies the requirements for the CTG. The Department minimized adverse impacts by reaching out to well owners and operators over the course of three years in order to obtain information to better inform the development of the proposal. The greatest impact expected from the proposal is the additional cost of LDAR. To help counter this the Department included alternative technology pathways so that impacted sources may use less expensive alternative methods as they become available.

SMALL BUSINESS AND LOCAL GOVERNMENT PARTICIPATION

The Department met with the Independent Oil and Gas Association of New York (IOGA-NY) three times and presented at the IOGA-NY annual meeting twice prior to the proposal of this regulation to allow rural and local government participation. In addition, a posted a stakeholder outline was posted on the DEC website to encourage stakeholder participation and comment.[2]

CURE PERIOD OR AMELIORATIVE ACTION

No additional cure period or other opportunity for ameliorative action is included in proposed Part 203. This proposal will not result in immediate violations or impositions of penalties for existing facilities. To help reduce immediate impacts on affected sources, Part 203 requires a compliance plan due within a year of promulgation followed by LDAR and operational requirements that begin on January 1, 2023. This will allow owners and operators of affected sources time to comply with proposed Part 203.

INITIAL REVIEW

The initial review of this rule shall occur no later than in the third calendar year after the year in which the rule is adopted.

[2] https://www.dec.ny.gov/chemical/113887.html.

Assessment of Public Comments Summary

6 NYCRR Part 203, Oil and Natural Gas Sector

6 NYCRR Part 200, General Provisions

Comments received from May 12, 2021 through 5:00 p.m. July 26, 2021

The Department of Environmental Conservation (Department) is adopting 6 NYCRR Part 203, Oil and Natural Gas Sector (Part 203) and 6 NYCRR Part 200, General Provisions. Part 203 will regulate volatile organic compounds (VOCs) and methane (CH_4) emissions from the oil and gas sector. This proposal will fulfil three New York State obligations: (1) reduce greenhouse gases (GHGs) in support of the requirements of the Climate Leadership and Community Protection Act (CLCPA), (2) reduce associated VOCs, and (3) fulfill the requirements of the Environmental Protection Agency's (EPA) 2016 Control Techniques Guidelines (CTG) for the oil and gas industry.

The Department proposed Part 203 on May 12, 2021. The public comment period closed at 5:00 P.M. on July 26, 2021. The Department received written and verbal comments from over 400 commenters on proposed Part 203. All of these comments have been reviewed, summarized, and responded to by the Department.

The vast majority of commenters, while supportive of proposed Part 203, emphasized the need to further strengthen the rule and go beyond federal requirements. Most notably, comments on specific aspects of the proposed rule addressed the frequency of leak detection and repair (LDAR), storage vessel thresholds and vapor control efficiency, blowdowns at compressor stations, potential exemptions for low-producing wells, and the need for continuous emission monitoring. Many commenters also opposed portions, or all of the requirements proposed in Part 203. These commenters expressed concern regarding the potential costs of meeting the requirements of Part 203 and some commenters questioned the need for some or all of the requirement of Part 203. The Department's responses to these and all other comments received are summarized below.

A significant number of comments received were asking the Department to make Part 203 as strong as possible, to go above and beyond federal requirements for reducing oil and gas pollution. In response the Department agreed that a strong and ambitious regulation to reduce GHG and air pollutants was in the best interest of New Yorkers and consistent with CLCPA requirements. The Department's response also acknowledged that Part 203 has gone above and beyond federal requirements in several areas, including: reporting of pigging operations; including metering and regulating stations in LDAR requirements; allowing for continuous emissions monitoring as the technology improves; requiring advanced notice of planned blowdowns and reporting of unplanned releases; and including no minimum threshold for wells, which would have exempted most wells in New York State.

Many commenters supported the Department's LDAR requirements, but urged the Department to increase LDAR frequency, specifically urging the Department to require monthly LDAR of natural gas wells and compressor stations. In response, the Department noted that studies have shown that increasing LDAR frequency beyond the frequency required by the proposed rule may result in limited further emission reductions while significantly increasing costs for operators. The Department also stated that it believed that the requirements, as written in Part 203, will significantly reduce emissions.

While many commenters approved of the inclusion of storage vessels in Part 203, they suggested the Department decrease the storage vessel threshold from 6 tons per year (TPY) to 2.7 TPY and also suggested increasing the vapor control efficiency for storage vessels from 95 to 98%. In response, the Department noted that it believed that the existing 95% vapor control efficiency and 6 TPY thresholds will significantly reduce emissions from tanks. Further, the Department will be collecting and reviewing data through Part 203's information collection provision for baseline reporting and the Department will work towards revising the regulation if it determines that additional controls are warranted after analyzing the collected data.

Many commenters supported the Department's requirements for blowdown notification and reporting, but urged the Department to lower the blowdown notification threshold from 10,000 scf to 2,500 scf, require operators of compressor stations to capture emissions from scheduled blowdowns, and to strengthen community notification requirements for planned and unplanned blowdowns. The Department stated that it believes the 10,000 scf threshold ensures that there are adequate resources to evaluate and follow-up after each release event to make this a meaningful process. The Department believes that this requirement is more stringent than other states and also notes that there are no federal requirements for blowdown notification. The Department also noted that it will work with the regulated community to ensure that reporting requirements are effective, and that the Department will propose changes if it believes that the reporting requirements are not effective for notifying the community.

Many commenters urged the Department to require stricter deadlines for repair on all infrastructures. Commenters believed that the 30-day requirement for repair times should be reduced to 14 days. Some commenters also urged the Department to include significance thresholds for leaks that would necessitate even more rapid repairs. In response, the Department stated that it worked with many stakeholders and industry experts during the pre-proposal stakeholder period. Through this outreach, the Department believes that the repair and replacement deadlines set in the regulation are feasible. The Department noted that it set these timeframes to reduce the potential for delay of repair requests.

Several commenters urged the Department to require continuous emission monitoring systems (CEMS). The Department noted that continuous monitoring is allowed as alternative leak detection technology, subject to approval by the Department. The Department also recognized that there may be significant potential for CEMS in the future, however, at the time of Part 203 rule development, there were three challenges to the utilization of CEMS in the natural gas sector: technical availability, determination of equivalency to approved methods, and lack of cost data for review. Based on these challenges, the Department decided not to require CEMS at this time.

Several commenters hoped that the Department would exempt “low-producing” wells from the requirements of Part 203, with one commenter mentioning a threshold of 3,500 million cubic feet (MCF) per year or 15 barrels of oil equivalent (BOE) per day for existing wells. Some other commenters hoped that well-maintained personal wells could qualify for heritage/grandfather status. In response, the Department stated that exempting low-producing wells in New York would result in almost all wells being exempt from the requirements of Part 203, which would reduce the emission reduction benefits of the rule. The Department decided to not adopt the exemption that the EPA and some other states have adopted for existing low-producing wells. Exempting low-producing wells would result in fewer emissions reductions, which New York needs to meet the requirements of the CLCPA. The Department also noted that several studies support the phenomenon of super emitters, and therefore the Department decided to cover all affected sources in the state and not exempt smaller sources.

Many commenters expressed concern that there are not enough qualified testers in their area to meet the twice a year testing requirement and that it would also be difficult for the tester to return for any required repairs. In response, the Department stated that it has not received any documentation or evidence demonstrating that testers are not available. If there are documented issues with the number of qualified testers that affect the ability of regulated entities to comply with the regulation it can be addressed at that time.

Many commenters stated that the studies that the Department used to determine possible VOC emissions were based on wells and well sites that were not representative of those in New York and did not reflect how their wells and well sites operated. The Department responded that it relied on available data and research to determine the emission impact form wells. The Department noted that some data did include conventional wells similar to those in New York. To enhance our understanding of New York's system, the Department included section 203-10.1 in this rulemaking, to collect that additional data.

Commenters also expressed concern that the costs of meeting proposed requirements in Part 203 are too high. Commenters stated that costs would exceed the value of production from their wells, projected fees for qualified testers and for leak repair would be prohibitive for single well owners, and that the proposed requirement to report to two additional Department divisions is an extra burden and cost on their fixed income. One commenter stated that the proposed regulation will not be economically viable for small business or single-use well owners for several reasons. This commenter also noted that many homeowners and small businesses will have to prematurely plug their self-use well, and then have to find another source of energy to meet their demand, which may be less clean. In response, the Department noted that Part 203 was developed to reduce GHGs and VOC emissions in a meaningful yet feasible way. The Department also noted the cost to well owners in the Part 203 support documents and that depending on well throughput some wells will cost more per unit output to meet the proposed requirements.

Several commenters provided suggested edits to many of the definitions that are included in Part 203. The Department included some of these edits when revising the Part 203 Express Terms. The Department made non-substantive updates to clarify some of these definitions. This included the definitions of city gate, metering station, natural gas gathering and boosting station, and pigging. The Department disagreed with many suggested edits as the rule as written was appropriate and the language was consistent with the language that had been used in other natural gas regulations in other states.

A couple of commenters opposed the requirement to include a component list as part of the LDAR program. The commenters stated that this would add burden without providing any environmental benefit and would be of little utility. The Department disagreed. The Department stated that a component list would give both the Department and regulated entities a better understanding of where leaks exist and where a need for potential future requirements exist. The Department also believes that a component list will help to inform the reporting requirements of the CLCPA.

One commenter had several comments related to the Department's legal authority for Part 203. The commenter stated that Part 203 bypasses the substantive and procedural requirements of the CLCPA. This commenter also stated that the Department had not established a legal basis for the measures contained in Part 203 to regulate methane or VOCs from the transmission and storage (T&S) sector. In response, the Department stated that while Part 203 is consistent with the GHG reduction requirements of the CLCPA, as well as recommendations in the Draft Scoping Plan, it is adopted primarily pursuant to the Department's existing statutory authority under Environmental Conservation Law (ECL) Article 19. Moreover, nothing in the CLCPA requires the Department to wait for the finalization of the Scoping Plan prior to taking additional regulatory measures to reduce GHG emissions. For the T&S sector, the Department stated that addressing VOC emissions is in line with the Department's efforts to address ozone pollution throughout the state and the Department determined that the anticipated VOC reductions are meaningful and necessary.

One commenter had several comments related to the social cost of methane (SCM) that the Department used. This commenter believed that the SCM used by the Department may be inaccurate and based on flawed methodology. The commenter stated that the SCM methodology used does not adequately incorporate air quality related impacts and the costs used by the Department are underestimated. In response, the Department stated that it believed that the methodology used is the most appropriate approach for estimating the societal damage of methane emissions, as it is consistent with the proven methodology that was developed by the Interagency Working Group and reflected in the Department's CLCPA Value of Carbon guidance.

6 NYCRR Part 203, Oil and Natural Gas Sector

6 NYCRR Part 200, General Provisions

Assessment of Public Comments

Comments received from May 12, 2021 through 5:00 p.m. July 26, 2021.

General Comments

Comment 1: Commenter asks the Department to make the regulation as strong as possible (Commenter 5, 29, 30, 35, 292, 297, 309, 407, 423)

Comment 2: It is imperative that the DEC promulgate the most rigorous rules possible to significantly cut oil and gas sector greenhouse gas emissions and toxic pollution (Commenter 171, 254, 293, 298, 303, 422)

Comment 3: We strongly urge the DEC to get these new rules right and urge state agencies to use their authority to rapidly transition away from fossil fuels and its infrastructure to meet New York's climate mandates, not derail them. (Commenter 243, 246, 422)

Comment 4: Require operators to adopt best available technologies to eliminate, capture or reduce emissions, to the greatest extent possible. (Commenter 193)

Comment 5: Every available technology tool and efficiency should be incorporated into this rule (Commenter 422)

Response to comments 1-5: The Department agrees that a strong and ambitious regulation to reduce methane and volatile organic compound (VOC) emissions is in the best interest of New Yorkers. With this in mind, the Department is adopting an ambitious and in many ways nation-leading regulation. For example, Part 203 addresses emissions from all wells while the EPA and other states exempt existing low-producing wells. Furthermore, Part 203 regulates often-overlooked metering and regulating stations and collects data for pigging activities as well as component counts to inform potential future regulation.

Comment 6: The timing of the reporting in March is not practical. (Commenter 408)

Response to comment 6: The Department respectfully disagrees, noting that the March date coincides with existing Division of Mineral Resources data requirements to reduce the burden on source owners.

Comment 7: Commenter supports the rule. (Commenters 217, 232, 298)

Response to comment 7: Thank you for the comment.

Comment 8: There should be much more coordination with the state health department (Commenter 428)

Comment 9: We urge the consideration of material public health and environmental impact in a holistic manner when you implement and effectuate rulemakings and oversight. (Commenter 435)

Response to comments 8 -9: Thank you for your comments. The Department notes that we regularly consult with the Department of Health and other State Agencies and Authorities in the development and implementation of our programs.

Comment 10: I would argue that the amount of wood required to burn to heat my home would have a more significant negative impact on the environment and produce a larger carbon footprint than my current gas usage does. (Commenter 380)

Response to comment 10: Thank you for your comment.

Comment 11: This rule is detrimental to small businesses. (Commenter 408)

Comment 12: I feel this is a very unfair regulation you are trying to push forward. (Commenter 445)

Comment 13: Please consider not moving forward with these proposals. (Commenter 316)

Comment 14: The proposed regulations would impact us in a negative manner (Commenters 63, 70, 75, 84, 89, 90, 158, 163, 165, 168, 169, 240, 325-379, 384-403, 412-418, 441-444, 446, 447, 448, 450, 451)

Comment 15: Regulating or imposing additional restrictions on an already encumbered industry could surely mean the death of this sector in New York. (Commenter 166, 406)

Response to comments 11-15**:** Part 203 was developed to reduce greenhouse gas and VOC emissions in a meaningful yet feasible way. The Department noted the cost to businesses in the Regulatory Flexibility Analysis for Small Businesses and Local Governments and further discussed the costs on various entities and for particular equipment types in the Regulatory Impact Statement (RIS). The Department understands that, depending on well throughput, there may be some challenges in meeting the requirements. The adoption of Part 203 is necessary to protect the health and welfare of New York residents and resources, and the reduction of methane emissions supports the requirements of the Climate Leadership and Community Protection Act. In fact, as discussed in the RIS, the cost of reducing emissions from relevant sources pursuant to the rule is significantly less than the value achieved by the reductions.

Comment 16: DEC should incorporate all voluntary recommendations from EPA's Natural Gas STAR program framework into this rule (Commenter 306, 439).

Response to comment 16: The Department considered all of EPA's Natural Gas STAR program feedback and incorporated many components into Part 203. The Department will continue to collect data through the information collection provision for baseline reporting in section 203-10.1. If the Department determines that additional controls are warranted, the Department will consider revising the regulation in the future.

Comment 17: The Coalition respectfully request that the Department postpone the rulemaking until the federal EPA and Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations are finalized and the scoping process under the Climate Leadership and Community Protection Act (CLCPA) is complete. (Commenter 307, 289)

Response to comment 17: The Department does not believe that it is prudent or necessary to delay the rulemaking any further to wait for federal EPA or PHMSA regulations. Even prior to EPA's anticipated adoption of proposed oil and gas sector regulations to reduce emissions, New York is statutorily obligated to adopt many of the regulatory provisions of Part 203 per EPA's existing oil and gas control technique guidelines (CTG). Further, New York has State obligations to its citizens to meet the requirements of the CLCPA.

The Draft Scoping Plan developed by the Climate Action Council, which is currently available for public comment, under the CLCPA recommends support for this Departmental rulemaking. Regardless, while the adoption of Part 203 is consistent with the requirements of the CLCPA to reduce Statewide greenhouse gas emissions and with the recommendations in the Draft Scoping Plan, the Department need not wait for the finalization of the Scoping Plan to take additional regulatory measures to reduce greenhouse gas measures. The Department will continue to refine and develop regulations, if warranted, as more information becomes available in the future.

Comment 18: The regulation should leverage existing and imminent federal requirements that apply to the same facilities, activities and pipelines. (Commenter 299)

Comment 19: DEC should ensure that the Regulatory Impact Statement (RIS) accurately and adequately supports rule requirements. (Commenter 299)

Comment 20: The RIS and other background material appears to provide limited analysis and justification of the proposed requirements. In many cases, proposed requirements are supported by outdated information. (Commenter 299)

Comment 21: DEC should allow the EPA process to proceed to minimize duplicative or overlapping requirements. (Commenter 299)

Comment 22: The regulation should be based on the best available information on methane emissions from natural gas T&S operations. In general, the RIS and other background material provide very limited analysis and justification of the proposed requirements. In many cases, the Proposed Rule cites outdated information. (Commenter 299, 307)

<u>Response to comments 18-22:</u> The Department believes that the data and materials reviewed relative to known oil and gas activities and components in New York State was used appropriately in the RIS. The Department further believes that Part 203 will result in significant methane and VOC reductions. The Department does acknowledge that a number of studies are based on activities in other areas of the country that have more oil and gas activity or allow for high volume hydraulic fracturing, and that some data will not exactly represent New York State oil and gas activities. However, the Department believes that as presented in the RIS, the information offers a reasonable estimate of the expectations from this rulemaking. The Department will continue to review new data and peer reviewed studies and will be collecting data through the information collection provision for baseline reporting in section 203-10.1. If, after the Department analyzes new information, the Department determines changes are warranted, the Department will work towards revising the regulation at that time.

Comment 23: The Coalition respectfully requests that the Department revisit the need for and expected emission reduction benefits of its proposed regulations in light of the reinstatement of key federal VOC and methane rules since the publication of the proposed rule and the rules that President Biden has directed the Environmental Protection Agency (EPA) to promulgate in the near future. (Commenter 307)

<u>Response to comment 23:</u> The Department believes the rulemaking should move forward. The emissions reductions in the regulatory support documents are based on current estimated activity and emissions, compared against what the Department expects to see after the rule is promulgated. Potential future federal regulations are not yet finalized. The Department notes that an initial review of proposed federal regulations indicates that the Department's regulation may contain more stringent requirements, which will remain necessary to reduce greenhouse gas emissions consistent with the CLCPA and VOC reductions to help achieve ozone NAAQS attainment. The Department will thoroughly review those federal regulations and proceed accordingly once they have been adopted by EPA.

Comment 24: The current proposal is disappointingly incomplete. (Commenter 284)

Comment 25: The crisis of climate destabilization demands stronger rules than what is proposed. (Commenter 263)

Comment 26: Urge DEC to use its clear legal authority to continue to go above and beyond the federal requirements for reducing oil and gas pollution – specifically methane – as part of its proposed rulemaking. (Commenter 243, 255)

Comment 27: It is imperative that the DEC go above and beyond the federal requirements to significantly reduce climate pollution and toxic emissions. (Commenter 246)

Response to comments 24-27: As stated in the RIS, the Department agrees that it has authority to require additional reductions in methane emissions pursuant to various provisions of Article 19 of the Environmental Conservation Law (ECL); such requirements are also consistent with the statutory requirements of the CLCPA. The Department believes that Part 203 is a strong first step in regulating emissions from the oil and gas sector in New York. More importantly, the Department has gone above and beyond the existing federal requirements in Part 203. Some of the areas in the regulation where the Department has gone beyond existing federal requirements include:

- Reporting of pigging operations.
- Advance notice of planned blowdowns and reporting of unplanned releases.
- LDAR at all wells, no minimum threshold which would exempt most New York State wells.
- The inclusion of metering and regulating stations in LDAR requirements
- The allowance of continuous emissions monitoring as the technology improves.

Comment 28: Methane in the presence of sunlight also forms formaldehyde, a known human carcinogen that can affect nearly every tissue in the human body. Commenter cited Macy, et al.[1] (Commenter 246)

Response to comment 28: The citation that the commenter used, Macy, et al., attributed the statement to Ingraffea, et al. The Department reviewed the Ingraffea, et al.[2] citation for this comment and found that the statement that formaldehyde was formed from methane in the presence of sunlight could not be attributed to that referenced study. The Ingraffea citation did not contain a conclusive statement supporting the commenter's statement. DEC staff continued to investigate and did find a peer-reviewed journal article by Still et al.[3] which indicates that in the in the remote marine boundary layer, the primary formation of formaldehyde may be from methane. The Department will continue to research this topic and if, after it reviews the collected data, the Department determines that additional controls are warranted, the Department will work towards proposing revisions to the regulation at that time.

Comment 29: The DEC should also update regulations to cover combustion sources as these are also significant sources of methane and VOCs. (Commenter 255)

Comment 30: Include combustion sources in this regulation, they are also significant sources of volatile organic compounds (VOCs) and methane. (Commenter 243, 246)

Response to comments 29 & 30: Part 203 addresses VOC and methane (CH4) emissions through leakage and other releases. Many combustion sources in the oil and gas industry are subject to existing regulations. For example, many are permitted under Part 201, subject to emission limits as defined in Part 227 and also may be subject to new and modified source requirements in Part 231. Moreover, relevant permit applications for combustion sources in the oil and gas sector are subject to the requirements of CLCPA Section 7.

Comment 31: This proposal seems like a waste and is better suited for big wells near big cities where it has a chance of making a difference. (Commenter 156, 157 & 405)

[1] https://ehjournal.biomedcentral.com/articles/10.1186/1476-069X-13-82#citeas

[2] Ingraffea, Anthony R. et al. (2014) "Casing and cement impairment in oil and gas wells." Proceedings of the National Academy of Sciences Jul 2014,

[3]https://www.researchgate.net/publication/29628717_Ambient_formaldehyde_measurements_made_at_a_remote_marine_boundary_layer_site_during_the_NAMBLEX_campaign_-_A_comparison_of_data_from_chromatographic_and_modified_Hantzsch_techniques

Response to comment 31: The Department disagrees. Methane and VOCs are emitted from small and large wells. Methane has been proven to contribute significantly to climate change and once it mixes in the atmosphere it has global impacts.

Legal/Legislative Authority

Comment 32: The Coalition is concerned that the Proposed Rule is inconsistent with and bypasses substantive and procedural requirements of the Climate Leadership and Community Protection Act (CLCPA) More specifically the commentor states that: (Commenter 307)

- The Proposed Rule is inconsistent with the requirements of the CLCPA because the Climate Action Council has not even finalized the Scoping Plan.
- With the Proposed Rule, the DEC has jumped well ahead of the process expressly outlined in the CLCPA.
- We respectfully submit that the Department should wait to receive and review the Scoping Plan before moving forward with sector-specific regulations.

Response to comment 32: While Part 203 is consistent with the GHG reduction requirements of the CLCPA, as well as recommendations in the Draft Scoping Plan, it is adopted primarily pursuant to the Department's existing statutory authority under Environmental Conservation Law (ECL) Article 19. Regardless, the rule does not bypass any requirements of the CLCPA. Nothing in the CLCPA requires the Department to wait for the finalization of the Scoping Plan prior to taking additional regulatory measures to reduce GHG emissions. See also responses to comments 17 and 24-27.

Comment 33: The Coalition is concerned that the Department has not established a legal basis for the measures contained in the Proposed Rule to regulate methane or VOCs from the T&S sector. The Coalition urges the Department to recognize that neither state nor federal laws provide a basis for comprehensive VOC regulation of the transmission and storage (T&S) segment. Further stating that the need to comply with the CTGs is not a basis for comprehensive regulation of the T&S segment and that the only sources in the T&S segment to which the CTGs apply are storage vessels that have the potential to emit VOCs in an amount greater or equal to 6 tpy. In our view, the Department should follow the EPA in determining that the costs and impracticality of imposing VOC regulatory measures on sources in the T&S segment other than storage vessels is not warranted given the negligible VOC reduction benefits from such regulation. Commenter goes on to state that with the exception of storage vessels, there is not a Clean Air Act-based obligation for VOC regulation of the T&S segment. (Commenter 307)

Response to comment 33: The Department is not limited to Clean Air Act-based obligations in its authority to address air emissions. As stated in the RIS, "Article 19 of the ECL was enacted to safeguard the air resources of New York from pollution and ensure the protection of the public health and welfare, the natural resources of the state, and physical property by integrating industrial development with sound environmental practices. It is the policy of the state to require the use of all available, practical and reasonable methods to prevent and control air pollution in New York. To facilitate this objective, the Legislature granted specific powers and duties to DEC, including the power to adopt and promulgate regulations to prevent, control and prohibit air pollution." Part 203 is clearly within the Department's legal authority to address air emissions as laid out in ECL Article 19, as further described in the RIS.

In addition to the above, New York must also fulfill its obligations under the EPA's 2016 Control Techniques Guidelines (CTG) for the oil and gas industry, which includes requirements to lower VOC emissions from existing sources. While the CTG may be more limited in its application than Part 203, Part 203 is tailored to address New York's unique air emission issues and progressive CLCPA goals and requirements. Addressing VOC emission, which contribute to ozone formation, from the T&S segment of the oil and gas industry is also in line with the Department's continued efforts to address ozone pollution throughout the state. Based on the above, the anticipated VOC reductions are meaningful and necessary.

Comment 34: If the Department elects to go forward with state methane or VOC regulation, the Coalition respectfully urges the Department to properly tailor such regulation in light of the overlapping federal initiatives and to avoid unnecessary duplication or regulatory conflict and uncertainty. The Coalition urges the Department to ensure that any state VOC and methane regulations it may promulgate leverage and coordinate with the federal requirements already applicable to the relevant facilities. The Regulatory Impact Statement (RIS) does not take into account existing and announced federal law, justify exceeding federal laws, or address the basis for duplicating federal requirements. (Commenter 307)

Response to comment 34: The Department considered both existing and potential relevant federal laws in its development of Part 203. The Department believes proposed Part 203 addresses the critical need to address air emissions, including VOCs and methane, from the oil and gas sector while avoiding unnecessary duplication, regulatory conflict or uncertainty with federal or other state regulations. Part203 is partially in response to the need for New York to fulfill its requirements laid out under the 2016 CTG. Furthermore, the Division of Air Resources consulted other divisions within the Department to ensure Part 203 was not contradictory to existing State regulation of the sector. As stated, in the RIS, Part 203 addresses New York's obligations under the Federal CTG while also addressing the State's commitment to reduce GHGs under the CLCPA and achieving VOC reductions that are necessary to achieve ozone National Ambient Air Quality Standards (NAAQS) attainment. See also response to comment 23.

Comment 35: The Department should revisit the Proposed Rule in light of the reinstatement of the 2012 Rule and 2016 Rule (EPA's NSPS rules). We urge the Department to consider the confusion resulting from the overlap and duplication of the Proposed Rule with the Subpart OOOOa Rule and the new rule that EPA will propose in September. The Proposed Rule has various requirements that deviate from the Subpart OOOOa rule in ways that will create confusion without yielding additional, quantified environmental benefits. (Commenter 307)

Response to comment 35: EPA's NSPS rules (OOOO and OOOOa) have been subject to regulatory uncertainty in the recent past. Despite this, the Department believes addressing new sources in the oil and gas sector is critical. During the development of Part 203, the Department considered the requirements and controls laid out in the NSPS rules, the unique structure of the oil and gas industry and resulting air emissions, and New York's progressive commitments to reduce GHGs and address climate change under the CLCPA. The Department believes that there is regulatory clarity for sources within New York and what their requirements will be under Part 203. Even where Part 203 deviates from federal rules, including the NSPS rules, the regulation is within the Department's authority and will help to further protect the public health and environment. Further discussion of the expected environmental benefits can be found throughout the RIS.

Comment 36: The Coalition respectfully requests that the Department revisit the basis and need for the Proposed Rule in order to avoid an arbitrary and capricious outcome. In particular, in calculating the incremental contribution (if any) of state-specific methane regulation to meeting the 2030 statewide emission limit, the baseline should reflect all of the reductions that will be achieved by the federal regulations. (Commenter 307)

Response to comment 36: Part 203 fully complies with the requirements of the State Administrative Procedures Act (SAPA) and is neither arbitrary nor capricious. Moreover, with respect to the CLCPA's 2030 Statewide GHG emission limit – as established in ECL Section 75-0107 and reflected in 6 NYCRR Part 496 – the adoption of Part 203 is consistent with the requirement to reduce Statewide GHG emissions across all sectors by 40% from 1990 levels. Beyond the adoption of Part 203, additional regulatory actions will be necessary, including measures recommended in the Scoping Plan, to ensure the achievement of the 2030 Statewide GHG emission limit.

Applicability

Comment 37: I am hoping the changes proposed are focused on regulating wells and their subcomponents on much larger scales than ours. Can you confirm this? (Commenter 64)

Response to comment 37: The proposed rule applies to all wells in New York. The Department did not adopt the exemption for lower-producing wells that EPA and some other States adopted.

Comment 38: Non-commercial, self-use gas wells and their appurtenances should be exempt from Part 203. Self-use wells are unique and should be considered separately. The Department should consider exempting any well that produces less than 3,500 MCF per year. (Commenter 91)

Commenter states that self-use wells are not a significant part of the oil and gas inventory or source of air emissions in New York. (Commentor 91)

Response to comment 38: A minimum threshold would result in most New York State wells being exempt from the requirements of the rule, which would substantially decrease the emission reduction benefits of the regulation as discussed in the RIS. This change would result in fewer emissions reductions, including the GHG emission reductions that New York needs to meet the requirements of the CLCPA.

Comment 39: There are homeowners that receive natural gas from connections to IOGANY member gas wells. Contractually, the equipment does not belong to the producing company. It is the responsibility of the homeowner to care for the connection to their homes. The homeowner equipment is located downstream of the lease custody transfer. The producing company's responsibility ends at the valve the homeowner connects to. Beyond this valve, there may be other valves, relief valves, regulators, fittings, meters, and pipeline to the home. If a component is leaking, the production company is unable to repair the leak. Commenter interprets the rule to require the homeowner to be the responsible party that conducts or hires a contractor to perform the LDAR monitoring and reporting of this equipment downstream of the custody transfer. Can NYSDEC confirm this. (Commenter 265)

Response to comment 39: The commenter is correct. The homeowner is responsible to comply with the requirements of Part 203 under the circumstance described in the comment.

Comment 40: For the Department's proposed regulations to be truly meaningful, they must apply not only to upstream sites, but also to transmission and distribution facilities downstream of the city gate and to other facilities presently considered exempt. (Commenter 306).

Response to comment 40: Part 203 does not include sources beyond the city gate, however, that does not mean that efforts are not being made to address emissions from those sources. There is a large body of solutions for emissions reductions for the production, transmission and storage sub-sectors of the oil and natural gas sector, but emissions reduction strategies are not as concrete for the distribution sub-sector. While emission reductions from all sectors is important, including to meet the requirements of the CLCPA, the Department believes it important to move as quickly as possible and has made the decision to develop these requirements as a first phase in addressing statewide emissions from this sector and will consider the distribution sub-sector with further review.

Comment 41: What is the difference between (1) Oil and natural gas production, (2) oil, condensate and produced water separation and storage and (4) Natural gas gathering and boosting? (Commenter 265)

Response to comment 41: Subdivision 203-1.1(a) lists the sectors within the oil and natural gas industry that are subject to the requirements of Part 203. Production includes all activities associated with the production or recovery of products (see definition of "Production" in Section 203-1.3). Natural gas gathering and boosting includes all equipment and components associated with moving natural gas to a processing plant or pipeline (see definition for "natural gas gathering and boosting station" in Section 203-1.3). After extensive stakeholder outreach, the Department determined that some sources include gathering and boosting with production while others do not. As a result, these are listed separately for clarity of applicability. The Department added a category for oil, condensate and produced water separation and storage because this equipment may exist throughout different sub-sectors and by adding this to the list makes it clear what is covered by the regulation.

Comment 42: Does (6) Natural gas metering and regulating stations only refer to 203-6 City Gate? This could lead to confusion. For example, are well sites as defined in 203-1.3 Definitions as part of one or more of the following sectors? (Commenter 265)

- (1) Oil and natural gas production
- (2) Oil, condensate and produced water separation and storage
- (4) Natural gas gathering and boosting

Response to comment 42: There are natural gas metering and regulating station requirements for wells (203-2.3), gathering lines (203-3.3), storage sources (203-5.2), and at the city gate (203-6.1). The Department believes that these requirements are clearly defined in their corresponding Subparts.

Comment 43: Are compressors located at a well site excluded because Section 203-2 does not include requirements for compressors? (Commenter 265)

Comment 44: Some compressors on wells are using 4HP to 20 HP engines. Equivalent to push lawn mowers or small riding mowers. Are they going to be required to conform with regulation for large compressors? The size of compressor or volume of gas is not defined in the proposed regulations. (Commenter 295)

Response to comment 43 & 44: Compressors located at well sites are not covered under Part 203,but may be subject to other Department regulatory or permitting requirements.

Comment 45: Would Section 203-2 apply to oil and gas production operators' gas metering stations? These metering stations receive natural gas from nearby gas and oil wells. The natural gas flows to a 2-phase "drip" separator for separation of natural gas and any entrained brine/produced water. The brine/produced water flows to storage tanks. The natural gas flows to the sales meter then onto the sales pipeline. Brine/produced water is periodically removed via tank truck for disposal. This facility is considered upstream of lease custody transfer. (Commenter 265)

Response to comment 45: Yes, Section 203-2.3 states that metering and regulating components are subject to the LDAR requirements in Subpart 203-7. This includes at well sites, gathering lines and city gates.

Comment 46: Request that the rule specifically not require emission control requirements or vent gas measurement for compressors (reciprocation and centrifugal) located at well sites or an adjacent well site and servicing more than one well site. These well sites would not be considered "natural gas gathering and boosting stations." (Commenter 265)

Response to comment 46: Subpart 203-2 "Oil and Natural Gas Well Activities" lists the components that are subject to requirements. Compressor sources that service wells at well sites are not listed and therefore not subject to the requirements.

Comment 47: Suggest: 203-6.1 Metering and Regulating, (a) Applicability: The requirements in this section apply to all metering and regulating components at the City Gate upstream of the custody transfer demarcation point between a natural gas pipeline company/transmission system operator and a distribution system operator. (b) Metering and regulating components upstream of the custody transfer demarcation point are subject to the LDAR requirements in Subpart 203-7. (Commenter 270, 319)

Comment 48: 203-1.1 General Applicability (a): (6) Natural gas metering and regulating stations requires additional clarification as these facilities are often physically shared by both distributing gas utility companies and natural gas pipeline companies or transmission system operators. NGA believes the intent was natural gas metering and regulating station equipment and facilities upstream of the custody transfer demarcation point. NGA suggests the following alternate language for consideration by the Department in addition to a revised definition of 203-1.3(17) “Metering Station.” (Commenter 270, 319)

- (6) Natural gas <u>custody transfer</u> metering and regulating stations.

<u>Response to comments 47 & 48:</u> The Department’s intent is to capture emissions and leaks associated with the city gate operations. While the Department was clear in pre-proposal outreach and presentations that this regulation would not reach beyond the city gate, metering and regulating activities associated with the city gate, even if after a custody transfer, are subject to the requirements of the rule. No changes have been made in the final regulation.

Comment 49: The regulation should clearly define the affected sources within each of the natural gas industry segments, and clearly define boundaries between the different industry segments. (Commenter 299)

Comment 50: DEC should more clearly define the applicable industry segments and the boundaries for each segment. We respectfully request that the DEC revise the Proposed Rule to define each segment more clearly (i.e., production, gathering and boosting, transmission & storage, etc.) and the boundaries between segments using well-defined and commonly understood terminology. We recommend that the Department adopt the segment definitions from the EPA GHG Reporting Program, which provides clearer definitions of segment boundaries than those outlined in the Proposed Rule. (Commenter 307)

<u>Response to comment 49-50:</u> The Department worked with stakeholders during pre-proposal stakeholder outreach and requested feedback on an outlined proposal. In response to that feedback, the Department included additional general applicability language to clarify applicable segments. The Department believes this language to be clear and will work with the regulated community if any questions arise during the implementation phase of the regulation.

Comment 51: We recommend that the Department clarify that §203-2 only applies to production wells. (Commenter 307)

<u>Response to comment 51:</u> The Department expects that most wells will be production wells. However, all wells that operate more than six months will be subject to the LDAR requirements.

Comment 52: Recommend the following clarification to §203-5: “Natural gas underground storage” or “Reservoir” means all equipment and components, **<u>including the surface components of underground storage wells</u>**, associated with the temporary subsurface storage of natural gas in any underground reservoir, natural or artificial cavern or geologic dome, sand, or stratigraphic trap, whether or not previously occupied by or containing oil or natural gas. (Commenter 307)

<u>Response to comment 52:</u> The Department has reviewed the suggested clarification and believes that the additional language provides clarity without altering the meaning of the definition. The Department has made this non-substantive revision in the final rule.

Comment 53: “Well casing” should be removed from the §203-1.3 definition of “Component” because the bulk of a well’s casing is below ground and LDAR is not possible for below ground equipment. (Commenter 307)

<u>Response to comment 53:</u> As stated, LDAR is performed on above-ground components. The Department will leave well casing within the definition for those well casing portions that are above ground. This is clearly described in 203-7(b)(1) which states “The portion of well casing that is visible above ground is not considered a buried component.”

Comment 54: The Proposed Rule should be clarified to differentiate underground storage wells from production wells. For storage wells, we recommend that the Department more clearly delineate between “vent” and “leak” emission sources. (Commenter 307)

Response to comment 54: The Department believes that the definition of “leak” clearly states that it is unintentional. Intentional venting does not fall under the definition of leak.

Comment 55: At a minimum, we respectfully recommend that DEC comprehensively revisit Proposed rule §203-2 through §203-6 to clarify the affected emission sources and applicable mitigation requirement for each industry segment and source. (Commenter 299, 307)

Response to comment 55: Through the assessment of public comment process the Department has reviewed all Subparts in Part 203 and made non-substantive updates as necessary in response to those comments to improve upon and clarify the regulation.

LDAR

LDAR frequency

Comment 56: Reconsider the frequency of the LDAR for wells. Twice per year is excessive and not much can go wrong with limited equipment use. Once every 5 to 10 years is more reasonable. (Commenter 133)

Response to comment 56: Studies have shown that an LDAR frequency of every six months will result in greater emissions mitigation. Decreasing LDAR frequency would result in higher emissions and more leaks going undetected for longer periods of time. Based on this, the Department feels that twice per year frequency is necessary and justified.

Comment 57: Require monthly leak detection and repair (LDAR) of natural gas wells and compressor stations. (Commenters 2, 3, 4, 6-28, 31-34, 36-62, 65-69, 71, 73, 74, 76-83, 85, 87, 88, 93-132, 134-155, 159-162, 167, 170, 172, 174, 175, 177-192, 195, 196, 198-201, 204-216, 218-231, 233-235, 238, 239, 241, 242, 244, 245, 247, 250-252, 256-264, 266-269, 271-283, 285-287, 291, 292, 294, 296, 300, 301, 303-305, 308, 310-314, 317, 318, 320-324, 410, 411, 420, 421, 423, 426, 427, 431)

Response to comment 57: Studies have shown that increasing LDAR frequency beyond the frequency required by the proposed rule may result in a significant increase in costs while only achieving a small increase in emissions mitigation. The Department will continue to evaluate additional studies and information as they become available, including information collected pursuant to the information collection provisions in the regulation, and may make revisions to the required frequency of leak detection through future revisions to the regulation.

Comment 58: Improve requirements for leak detection and repair of natural gas wells and compressor stations so that leaks are detected and repaired quickly without extended periods of emissions release. (Commenter 254)

Comment 59: Adopt a quarterly, instrument based, comprehensive LDAR provision for all well sites rather than the proposed semi-annual inspection requirement. A comprehensive, instrument based robust LDAR program that requires operators to inspect for leaks on a quarterly basis and requires monthly auditory, visual and olfactory (AVO) inspections can significantly reduce emissions from abnormal operating conditions and leaks. (Commenter 203)

Response to comment 58 and 59: The Department believes that the existing LDAR requirements and frequency will significantly reduce emissions. The Department will be collecting data through the information collection provision for baseline reporting in section 203-10.1. If, after the Department reviews the collected data, is the Department determines that more frequent LDAR and AVO is warranted, the Department will work towards proposing revisions to the regulation at that time.

Comment 60: Leak detection and repair (LDAR) survey frequency should be clarified, and surveys should be required no more frequently than quarterly. (Commenter 307)

Comment 61: Consistent with Subpart OOOOa, quarterly survey frequency is more than adequate for T&S compressor stations, and the Department has not met its burden for demonstrating that it is necessary to exceed the federal standard. (Commenter 307)

Comment 62: For underground storage fields, less frequent surveys are warranted, and bi-annual (2x per year) survey frequency is recommended. If underground storage well surveys are required more frequently than every 6 months, winter weather conditions may make surveys difficult to conduct due to inaccessible equipment. (Commenter 307)

Comment 63: The Coalition recommends quarterly or less frequent surveys for compressor stations, twice-per-year or annual surveys for storage wells, and annual surveys for metering and regulating stations. Section §203-7.2 (c) requires "bimonthly" surveys at compressor stations. This is more frequent than for other segments, but the RIS does not provide a justification for the greater frequency. (Commenter 307)

Comment 64: The rule should provide that if an operator meets certain performance metrics for leak minimization, the operator may conduct less frequent surveys unless and until survey leak counts increase. (Commenter 307)

Comment 65: Less frequent surveys are warranted for metering and regulating stations. The coalition recommends annual surveys for metering and regulating stations. Depending on the situation, emissions from transportation to remote survey locations could exceed leak emissions at the site. (Commenter 307)

Comment 66: We urge the Department to add flexibility to change the survey frequency. The rule should allow operators to elect to conduct less frequent surveys when performance metrics are met. (Commenter 307)

Response to comments 60 - 66: LDAR survey frequency is clearly stated in section 203-7.2 "LDAR Frequency." The Department believes that different segments of the oil and natural gas sector warrant different LDAR frequencies. For example, as required by Part 203, transmission compressor stations and storage facilities are larger sources that have the potential for larger leaks, therefore the Department believes that the bimonthly LDAR schedule is best suited for this segment. The Department will evaluate all information collected during the rule's implementation phase to determine if additional flexibility and/or a change in LDAR frequency is warranted in a future revision to the rule.

Comment 67: Impose stricter timeframes and deadlines for leak detection and necessary repairs. (Commenter 193, 407)

Comment 68: Other jurisdictions have begun to require more frequent monthly LDAR for facilities with higher levels of potential or actual emissions or those located near occupied areas, Part 203 should follow their lead. (Commenter 284)

Comment 69: Bimonthly inspections for natural gas storage facilities and compressor stations in the natural gas transmission segment. (Commenter 203)

Response to comments 67 -69: The Department believes that the existing LDAR requirements and frequency will significantly reduce emissions. The Department will be collecting data through the information collection provision for baseline reporting in section 203-10.1. If, after the Department reviews the collected data, the Department determines that more frequent LDAR, the Department will work towards proposing revisions to the regulation at that time. While a few other jurisdictions may have recently adopted more frequent LDAR requirements for certain sources, we note that Part 203 has gone further than most jurisdictions by expanding the types and number of sources that are subject to the rule.

Comment 70: We recommend the NYSDEC remove the leak detection and repair requirement from the regulation. (Commenter 408)

Response to comment 70: The Department disagrees. There is extensive peer-reviewed research and data that demonstrates that leak detection and repair will significantly reduce emissions. revising the regulation.

Leak repair timing

Comment 71: Require shortened leak repair times. (Commenter 246, 255, 299)

Response to comment 71: The Department believes that the existing leak repair requirements are appropriate and, as written, provide reasonable time for action while still achieving significant emissions reductions. The Department will be collecting data through the information collection provision for baseline reporting in section 203-10.1. If, after the Department reviews the collected data, the Department determines that shortened repair times are needed, the Department will work towards proposing revisions to the regulation at that time.

Comment 72: LDAR delay-of-repair provisions should be presented in a single section of the rule and should ensure that adequate time is allowed when unavailability of parts warrants delay. Delay-of-repair reporting and recordkeeping should be streamlined. The Proposed Rule is confusing because delay-of-repair criteria are presented in multiple sections. We recommend consolidating all delay-of-repair provisions into a single section of this rule, §203-7.3 (f). (Commenter 307)

Response to comment 72: The Department believes that providing delay of repair requirements specific to each oil and natural gas segment is appropriate and that it provides clarity to the regulated community. This format allows regulated entities to find specific delay of repair information for each segment. In addition to the specific delay of repair requirements, there is an overall feasibility and safety provision in Subpart 203-9 that applies to all applicable sources.

Comment 73: DEC should consider the implications associated with parts availability and other reasonable causes for repair delay. We urge the Department to revise the delay-of-repair provisions to address the scenario in which lack of available parts causes a delay in repairs. The Coalition recommends utilizing delay-of-repair text from Subpart OOOOa, with that rule text supplemented to address the scenario where delay is warranted due to the unavailability of parts. (Commenter 307)

Response to comment 73: The Department did consider the implications associated with parts availability and other reasonable causes for repair delay. The Department provides delay of repair provisions in Subparts 203-2, 203-3, 203-4 and 203-7. Furthermore, there is a general feasibility and safety provision allowing delays due to specified conditions in Subpart 203-9.

Comment 74: If revised rule criteria are met, the operator should not have to notify the Department regarding delays beyond 30 days, and, an approach that categorizes systems as “critical” should not be included because it adds unnecessary complexity and ambiguity. (Commenter 307)

Response to comment 74: The Department believes that the notification of delays beyond 30 days is important information and should be submitted. In addition, there is a need to define systems as “critical” to ensure that only those have the option for a delay. The definition of “critical” is clear and if question arise, the DEC staff will work with the regulated entity to ensure clarity.

Comment 75: We urge the Department to allow operators to defer the repair until the next shutdown for maintenance if the repair cannot otherwise be completed. (Commenter 307)

Response to comment 75: The Department provides delay of repair provisions in Subparts 203-2, 203-3, 203-4 and 203-7. Furthermore, there is a general feasibility and safety provision allowing delays due to specified conditions in Subpart 203-9. Several of these provisions allow for delay of repair to occur at the next shut-down or within 12 months, whichever is sooner. The Department does not believe that a general provision to allow all repairs to wait until the next shut-down is warranted.

Comment 76: Recommended text for delay-of-repair provision: If the repair or replacement is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be complete during the next scheduled compressor shutdown **for maintenance**, well shutdown, well shut-in, ~~after a planned vent blowdown~~ or within 2 years, whichever is earlier. (Commenter 307)

- Delay of repair is allowed beyond the next scheduled compressor station shutdown for maintenance but within the 2-year period if replacement parts cannot be acquired before the next scheduled shutdown for maintenance. Replacement parts must be promptly ordered after determining delay of repair is necessary and repair requires replacement parts. The repair must be completed within 30 business days of receipt of the replacement parts, or during the next scheduled maintenance shutdown after the parts are received (if the repair requires a shutdown). A further extension may be approved on a case-by-case basis. (Commenter 307)

The Coalition recommends including another “good cause” exception for delay-of-repair. (Commenter 307)

Response to comment 76: The Department believes that the rule, as written, is appropriate and that it is consistent with other natural gas regulations in other states. As such, no revisions are warranted. If, after the Department reviews the collected data, the Department determines that changes to provisions are warranted, the Department will work towards revising the regulation.

Comment 77: The Proposed Rule should be revised to streamline reporting and recordkeeping, and other criteria associated with delay-of-repair. The “critical component” or “critical process unit” definitions and criteria in the Proposed Rule are ambiguous, burdensome, and fraught with peril that could cause the dilemma of an operator choosing between shutting down a facility and the reliable delivery of natural gas to customers in need. (Commenter 307)

Response to comment 77: The Department believes that the rule, as written, is appropriate and that it is consistent with other natural gas regulations in other states. As such, no revisions are warranted. If, after the Department reviews the collected data, the Department determines that changes to provisions are warranted, the Department will work towards revising the regulation.

Comment 78: If repair or replacement is delayed per 203-9, then for the purpose of following the CLCPA requirement for accurate inventorying, accurate measurement of calculation, not estimation, of methane emissions from the leak source must be made and reported for the duration of the delay. In the case of wellhead leaks from producing oil and gas wells, this delay could be many months or years. An expected result of enforcement of the proposed regulations is the identification of super-emitters among the approximately 10,000 active oil and gas wells in the state. There should be minimal delay in repair or, if necessary, attempted plugging of such wells. (Commenter 194)

Response to comment 78: The CLCPA does not require that leaks be measured pursuant to this regulation for an accurate greenhouse gas emission inventory.

The CLCPA, specifically ECL Section75-0105, requires the Department to prepare and issue an annual Statewide Greenhouse Gas Emissions Report, which among other things must utilize the best available science and methods of analysis. The Department issued the first of these annual reports at the end of 2021 utilizing the best available science and methods of analysis, as discussed in the Report, and will continue to do so in the development and preparation of future reports.

Similarly, ECL Section 75-0107 required the Department to utilize the best available scientific, technological, and economic information to determine the 1990 Statewide emission levels in the development of the Statewide emission limits rulemaking. The Department did so in the development and promulgation of its Part 496 regulation, as discussed further in the Part 496 RIS and other regulatory support documents.

Finally, ECL Section 75-0109 requires the Department, by January 1, 2024, to adopt legally enforceable regulations to ensure compliance with the Statewide greenhouse gas emission limits set in the CLCPA. In promulgating such regulations, the Department must ensure that greenhouse gas emissions reductions are real, permanent, quantifiable, verifiable and enforceable…"

As discussed in the RIS, while the adoption of this regulation is consistent with the requirements of the CLCPA by helping to achieve additional greenhouse gas emission reductions, Part 203 is being adopted primarily pursuant to the Department's existing statutory authority in various provisions of ECL Article 19. In any case, while the CLCPA requirements outlined above are not specifically applicable to this rulemaking, the Department does not interpret these CLCPA requirements to necessitate a measurement of every leak. The Department has chosen to identify leaks and repair as quickly as possible with limited delays to consider safety and reliability. To do this, the Department has included all wells, which neither the federal government nor other states have. Furthermore, the Department includes metering and regulating stations under the Part 203 provisions including data collection requirements. The Department believes that by expanding the processes and components subject to the rule and identifying and repairing leaks in this expanded area will lead to significant emissions reductions.

Continuous emissions monitoring

Comment 79: It makes no sense to limit the Department's review to occasional physical inspections, when cost effective monitoring equipment is now readily available. (Commenter 306).

Comment 80: Provide more information behind the decision to reject continuous emissions monitoring technology on the basis of technical availability. (Commenter 255)

Comment 81: Require installation and use of air monitoring equipment at the stack, fence line and within nearby communities to provide continuous monitoring of pollutants including toxic chemicals, criteria pollutants, ultra-fine particulate matter, individual VOCs, as well as methane in real time for all gas infrastructure facilities, with such data made readily available to the public such as by online access. (Commenter 171, 263, 302 407)

Comment 82: Every facility needs to have infrared flare cameras pointed on them at all times (Commenter 438).

Comment 83: The Department indicates that it considered requiring continuous emissions monitoring at all sites, but rejected this alternative “because at this time the Department does not believe that CEM technology is as advanced as needed.” The basis for this statement is questionable; California now requires continuous emissions fenceline methane emissions monitoring for natural gas storage sites. The Proposed Part 203 would allow continuous monitoring instead of LDAR at facility option, but if it will accept this technology, it is unclear why it would not consider requiring it for categories of facilities with greater actual or potential emissions. (Commenter 284)

Comment 84: DEC should provide more information to justify its reasoning to reject continuous emissions technology on the basis of technical availability, continuous emissions monitoring technology. (Commenters 243, 256, 305, 423)

Comment 85: Commenters request more information about what led DEC to this conclusion and what analysis was done to rule out continuous technology, specifically, what technology was considered, what were the detection limits of this technology, how reliable were the measurements, what was the frequency of measurement and data capture deemed to be “continuous,” was there difficulty in processing big data from many data points, was cost used as a factor to rule out continuous detection? (Commenter 243, 256, 305)

Comment 86: The technology does currently exist that is capable of monitoring fine particulate VOC and methane that would meet the needs of the DEC and operators (Commenter 423)

Comment 87: Insist on publicly accessible, continuous real time air emissions monitoring installed at leak-prone facilities including compressor stations (Commenters 288, 293, 302, 309, 424, 427, 433, 436, 438, 439).

Comment 88: Require publicly available real time continuous air monitoring of VOCs and PM 2.5 - continuous emission monitoring systems (Commenter 424, 425, 437)

Comment 89: We wish to emphasize the value of continuous air monitoring and data recording at all sites for methane, VOCs, and particulate matter. (Commenter 306)

Comment 90: Require publicly accessible continuous real-time air monitoring for volatile organic compounds (VOCs), particulate matter and methane. Air monitoring sensors are widely available and should be placed at fence line and in and around proximate communities to these oil and gas facilities. (Commenter 246)

Comment 91: Require continuous emissions monitoring systems, especially for sources that meet certain criteria such as major sources, facilities in areas that exceed federal air pollution standards, environmental justice areas and facilities with a history of harmful pollution or violations. (Commenter 193)

Comment 92: Technology is available for continuous emissions monitoring of methane in real time for gas infrastructure facilities. (Commenter 171)

<u>Response to comments 79-92:</u> The Department recognizes that there may be significant potential for continuous emissions monitoring (CEM) for certain sources. However, at the time of this rule development, there were three immediate challenges to the requirement of utilization of CEMs for methane in the natural gas sector: technical availability, determination of equivalency to approved methods, and lack of cost data for review.

1. Technical availability: While there are some pilot projects, there does not appear to be sufficient data to determine if this technology is readily available to support its application in Part 203 at this time. Furthermore, the Department has not received information that there is sufficient data to determine if the use of CEMS will result in the same emissions reductions as the methods approved under the control techniques guidelines (Method 21 and Optical Gas Imaging), which are currently

included as regulatory options. Some stakeholders provided information for LDAR currently in use, however the examples provided were at processing plants. New York does not have any processing plants and they are inherently different in containment, emissions and profiles from the sources subject to Part 203. When developing a reliable and appropriate CEM system, other factors such as meteorological conditions, leak detection sensitivity and emission rates must be fully evaluated.

2. Equivalency: A multi-state and academic effort is underway to define a “path to equivalency,” meaning a set of criteria to determine if an advanced monitoring method (e.g. CEMs) will result in equivalent or improved emissions reductions. When completed, this effort will result in peer reviewed equivalence criteria, that DEC could rely on in updating Part 203 during a future regulatory review.
3. Lack of cost analysis: Because CEMs are not readily available in the market there is limited cost data at this time.

The Department intends to continue this research and may move forward with a CEM requirement as more information is developed and evaluated.

Comment 93: Increase accountability by making records and air emissions data collected from operators publicly available (via a database or website). (Commenter 292)

<u>Response to Comment 93</u>: The Department is evaluating different modes and methods to make appropriate information associated with this regulation available to the public as quickly as practicable.

Thresholds & Exemptions

Comment 94: A well-maintained personal supply well should qualify for heritage/grandfather status. (Commenter 165, 237)

Comment 95: A benchmark of daily production should be applied to active wells which would exempt certain specific wells based on the very small amount of daily production. Wells producing less than the, to be established benchmark, would not merit the time and expense necessary to comply with deeper, much more prolific producing wells. (Commenter 406)

Comment 96: A minimum threshold should be established and those wells which produce under the threshold should be exempt. (Commenter 166).

Comment 97: LDAR should not be required for well sites because The CTG does not recommend LDAR for marginal and low producing well sites with less than 15 BOE/day based on twelve months rolling average production. Based on data from IOGANY membership, most facilities would have a BEO less than 0.5 BOE/day. Based on 2019 production data filed with NYSDEC New York State wells have an average production of 0.54 BOE/day. (Commenter 265)

<u>Response to comments 94-97:</u> While the EPA CTG allows for an exemption for lower producing wells, the Department has not adopted any exemptions for Part 203. Furthermore, the Department has evaluated and accepted the studies which define super-emitters. Studies suggest that methane emissions are

underestimated from this sector based on atmospheric research.[4,5] This underestimation may be due to super-emitters which represent a small fraction of sites but may be responsible for a large fraction of emissions. Many studies support this phenomenon[6,7,8,9] and it serves as a large part of the basis behind the Department proposal to cover all affected sources in New York State and not exempt the smaller sources as EPA and other states do. Based on New York State data, if the Department adopted a threshold such as that adopted by EPA and other states, over 95% of wells would be exempt from the requirements of this rule and the estimated emissions reductions and benefits would be reduced. See also response to comment 38.

LDAR General

Comment 98: The information contained in LDAR inspection documentation should be clarified (Commenter 243, 256, 305).

Response to comment 98: EPA Method 21 is well-defined and more information is available through EPA documentation.[10] OGI inspection is defined by device documentation. The information required by the Department includes leaks and repairs and the minimum data requirements for leaks are listed in subdivision 203-7.3(b).

Comment 99: Require leak detection on all equipment (Commenter 432).

Response to comment 99: The Department relied on peer reviewed studies and literature in determining that the components associated with wells, transmission, storage and the city gate offered significant emissions reduction potential in developing the provisions in the regulation. The Department will continue to monitor review data and studies to determine if other sectors or components should be added to the regulation at a later date.

Comment 100: Want operators to perform a quantitative analysis of concentrations for leaks (Commenters 432, 436)

Response to comment 100: The Department notes that the primary goal for this regulation is to reduce methane and VOC emissions associated with leaks and has therefore placed the greatest amount of emphasis in identifying and repairing those leaks.

Comment 101: Want very clear information on websites that the public can look at (Commenter 432).

Response to comment 101: The Department is evaluating different modes and methods to make appropriate information associated with this regulation available to the public as quickly as practicable.

Comment 102: Require quarterly inspection by independent registered personnel with regular reports submitted to the DEC and made available to the public to detect and ensure timely elimination of natural

[4] Brandt, A.R., et al. 2014. Methane Leaks from North American Natural Gas Systems. Science. Vol. 343.
[5] Miller, S.M., et al. 2013. Anthropogenic Emissions of Methane in the United States. Proceedings of the National Academy of Sciences. December 10, 2013.
[6] Brandt, A.R., et al. 2014. Methane Leaks from North American Natural Gas Systems. Science. Vol. 343.
[7] Lamb, Brian K, et al. 2015. Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States. Environmental Science & Technology.
[8] Zavala-Araiza, Daniel, et al. 2015. Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites. Environmental Science & Technology.
[9] Zimmerle, Daniel J., et al. 2015. Methane Emissions from the Natural Gas Transmission and Storage System in the United States. Environmental Science & Technology.
[10] https://www.epa.gov/emc/method-21-volatile-organic-compound-leaks

gas leaks at gas infrastructure facilities using the comprehensive detection methods such as aerial and ground-level laser methane assessment, organic vapor analyzers (OVAs), toxic vapor analyzers (TVAs), sorbent tubes, SUMMA canisters, infrared cameras, as well as real time monitoring with Fourier Transform Infrared (FTIR) spectroscopy and other remote sensing along pipelines. (Commenter 171)

<u>Response to comment 102:</u> The Department believes that the existing LDAR requirements in Subpart 203-7 will significantly reduce emissions. Department staff will continue to perform spot checks and if those checks as well as the data collected through the information collection provision for baseline reporting, 203-10.1, demonstrate that additional controls or monitoring types are warranted, then the Department will work towards revising the regulation.

Comment 103: Component lists should not be required for the LDAR program. This adds burden without providing an environmental benefit. Creating a component list for each piece of equipment at each facility would be unnecessary and of limited utility. It is especially burdensome when surveys are conducted using OGI, which is commonly employed. (Commenter 307)

Comment 104: The regulations should not require LDAR component lists for facilities that utilize optical gas imaging (OGI) technology to conduct LDAR surveys. (Commenter 299)

<u>Response to comments 103 & 104:</u> The Department disagrees. A component list will give the Department and the regulated entities a better understanding of where leaks exist and where a need for potential future requirements may exist. Furthermore, the component list is helpful in informing the reporting requirements of the CLCPA.

Comment 105: For LDAR methodologies: (1) the rule should clearly indicate that “soap bubble tests” are an acceptable LDAR methodology to confirm repair and that Method 21 methane instruments are acceptable; (2) criteria for implementing alternative techniques should be streamlined; and (3) quality assurance for continuous techniques should not mandate a periodic survey or inspection. (Commenter 307)

<u>Response to comment 105:</u> Part 203 allows for Method 21 or OGI to satisfy the LDAR requirements. The data and information required to support the use of alternative techniques is clearly listed in subdivision 203-7.1(c). The Department did not want to be more prescriptive so the solutions are technology agnostic. If alternative techniques are shown to be as reliable as the approved technologies, the Department will work towards proposing revisions to Part 203 to eliminate the requirements of a periodic survey or inspection.

Comment 106: Method 21 instrumentation for T&S segment facilities should not require both a methane and VOC capability, as specified in §203-7.1 (a)(1). (Commenter 307)

<u>Response to comment 106:</u> Part 203 addresses both methane and VOC emissions, as such, both pollutants must be addressed. The Department will work with the regulated community if any questions regarding equivalents arise during implementation.

Comment 107: The Coalition recommends that the rule include a higher-level framework of requirements for alternative techniques. The Department could accompany the rule with a more detailed guidance document. (Commenter 307)

<u>Response to comment 107:</u> Thank you for the feedback. The Department plans to work with the regulated community to address any questions and provide guidance as necessary. If, after consultation, the Department believes that a formal guidance document is warranted, it will develop one for public comment and feedback.

Comment 108: Alternative LDAR approaches should be evaluated either by equivalent emission reductions (likely at the company level) or technology-agnostic performance criteria categorized by function. (Commenter 203)

Response to comment 108: The Department addresses alternative and equivalent emission reduction methodologies in subdivision 203-7.1(c) which allows for Department approval of alternative methods. The Department will base approval on equivalent emissions reductions without preference of technology or methodology.

Comment 109: Inclusion of gas-powered pneumatic controllers in leak inspections. (Commenter 203)

Response to comment 109: Natural gas actuated pneumatic devices, including controllers, are subject to the LDAR requirements in Part 203. Depending on the sub-sector within the natural gas system, requirements may be found in subdivisions 203-2.2(d), 203-3.2(d), 203-4.2(d) and 203-5.1(b).

Comment 110: We believe the current approach, continuous monitoring + an annual OGI survey, is not a robust or practical approach for leak detection. (Commenter 203)

Response to comment 110: The Department disagrees. Newly developing continuous emissions monitoring for these purposes is showing potential as an effective leak detection technology. Furthermore, Part 203 requires that any continuous emissions monitoring must be at least as effective as OGI or Method 21. OGI has been demonstrated as an effective leak detection method for reducing natural gas emissions. The Department believes that the LDAR requirements are robust and will significantly reduce emissions. The Department will be collecting data through the information collection provision for baseline reporting in section 203-10.1 and LDAR reporting. If, after the Department reviews the collected data, the Department determines that changes are warranted, the Department will work towards revising the regulation at that time.

Comment 111: Regulations should include specifications of what constitutes a leak for Optical Gas Imaging. (Commenter 246)

Comment 112: DEC should specify what constitutes a leak for using optical gas imaging or OGI to meet LDAR requirements. (Commenters 243, 255, 256, 305, 423, 436)

Response to comment 111 & 112: The leak detection methodology in the regulation clearly informs how the technology or the methodology is to be calibrated. This calibration and methodology threshold defines the leak.

Comment 113: Under Part 203-7.1(b) it should be mandatory that operators opting to comply with LDAR mandates using OGI must guarantee that personnel using OGI be certified in its use. (Commenter 194)

Comment 114: Require that OGI operators be certified (Commenters 243, 255, 256, 305, 423).

Comment 115: DEC should also require that all OGI inspections performed with the intent of complying with LDAR be performed only by personnel certified in the use of the device (Commenter 243, 256, 305).

Response to comment 113-115: Paragraph 203-7.1(b)(2) requires that calibration, maintenance and OGI camera procedures of the equipment must be adhered to. The expectation is that this will ensure that OGI is used properly and effectively.

Comment 116: Under 203-7.3 Repair of Leaks, it is written that "…leaks shall be repaired within thirty (30) days of identification unless one of the conditions of 207-3(f) apply". We suspect that reference 207-3(f) is an error. Perhaps the reference should be to section 203-9, Feasibility and Safety, wherein there are 5 circumstances under which a repair can be delayed. (Commenter 194)

Response to comment 116: The Department thanks the commenter for pointing out that typographical error. Under Subpart 203-7, where it is written that "…leaks shall be repaired within thirty (30) days of identification unless one of the conditions of 207-3(f) apply" it should read "…leaks shall be repaired within thirty (30) days of identification unless one of the conditions of 203-7(f) apply." 203-7(f) outlines when a delay of repair may be granted. The Department has made this non-substantive revision in the regulation.

Comment 117: DPS already approves, and lists on their website, specific makes and models of analytical instruments as meeting the leak detection and survey requirements set forth in 16 NYCRR Part 255. Because the oil and gas sector is already equipped with and using approved leak detection instruments needed for compliance with Part 255, we request Section 203-7.1 of the proposed rule be simplified to recognize the continued use of these instruments, provided they are calibrated to meet the proposed Part 203 fugitive emissions threshold. We propose the following clarification to the express terms at 203-7.1: (d) Owners and operators may comply with the provisions of this section by using a device approved for use in "leak detection" and Leakage survey" under 16 NYCRR Part 255 this is (i) is set to detect fugitive emissions of 500 ppm CH_4 and VOC and (ii) calibrated to in accordance with the manufacturers' instructions. (Commenter 249, 270, 319)

Response to comment 117: Because the Department must comply with EPA's CTG, each approved leak detection method for methane or VOC detection must ultimately demonstrate equivalent emissions reductions. The Department believes that while Part 255 has a list of approved instruments, they must also be shown to make the appropriate reductions per the CTG. The Department does not believe that the proposed changes comply with the CTG and therefore has not incorporated them into the final regulation.

Comment 118: Unless and until repairs are made, just detecting a leak is a pointless exercise. The Department proposed timeframes for requiring repairs of leaking components are particularly weak. EPA's guidelines state "identified sources of fugitive emissions repairs…be repaired or replaced as soon as practicable, but no later than 30 calendar days after detection." The Part 203 proposal only requires that leaks "shall be repaired within 30 days." Other regulators mandate tighter timeframes for repairs. Utah requires repair of fugitive emissions component as soon as possible but no later than 15 calendar days after detection. California provides for a graduated schedule for repair times which ranges from 14 calendar days for smaller leaks (1000-9999ppm) up to 2 calendar days for major leaks (50,000ppm or greater) Part 203 should similarly provide for more rapid repairs of leaking equipment. (Commenter 284)

Response to comment 118: The Department disagrees. Part 203 requires that repairs are made after a leak is detected and therefore their detection is not a pointless exercise. There is limited substantive or enforceable difference between a requirement to "be repaired or replaced as soon as practicable, but no later than 30 calendar days" and "shall be repaired within 30 days." The expanded applicability under Part 203 warrants the 30 day repair times as Utah follows EPA RACT applicability which exempts wells that have a BOE of 15 or less.[11] If the Department followed this "lead" then over 95% of New York State wells would be exempt from any requirements. See also response to comments 38 and 94-97.

Blowdowns

Blowdown Capture

Comment 119: Require operators of compressor stations to capture emissions from scheduled blowdowns and develop specific limits for these events (Commenters 2, 3, 4, 6-28, 31-34, 36-62, 65-69, 71, 73, 74, 76-83, 85, 87, 88, 93-132, 134-155, 159-162, 167, 170, 172, 174, 175, 177-192, 195, 196, 198-201, 204-216, 218-231, 233-235, 238, 239, 241, 242, 244, 245-247, 250-254, 256-264, 266-269, 271-283, 285-287, 291,

[11] Section 9.4 of EPA's Control Techniques Guideline

293, 294, 296, 300, 301, 303-306, 308, 310-314, 317, 318, 320-324, 410, 411, 420, 421, 423, 424, 431, 436, 439)

Comment 120: DEC should require full capture requirements for scheduled pipeline blowdown gas with no venting to the atmosphere (Commenter 171, 256, 305, 423)

Comment 121: Require compressor stations and other emitting facilities to install a vapor control system so that gas from planned blowdowns is not vented into the air. (Commenter 424)
Comment 117: Planned blowdowns must be re-directed to lower-pressure pipelines or tanks instead of simply being released into the air. (Commenter 309)

Comment 122: DEC should require operators to use inert gas and re-capture blowdown gas rather than flaring (Commenter 243, 256, 305).

Comment 123: Require capture for scheduled blowdowns. (Commenter 246, 255)

Comment 124: Require control of emissions during blowdown operations. New York could also require operators to use techniques that reduce emissions during blowdowns such as reducing the pressure in the affected section of the pipeline with the use of downstream or mobile compressors before starting a blowdown or require flaring of gas instead of venting during blowdown operations. (Commenter 203)

<u>Response to comments 119-124:</u>   During the development of Part 203, the Department was aware of only one current technology that may have the ability to capture blowdowns under certain conditions. Given the current technological imitations the Department believes that the existing requirements for blowdowns is the most appropriate mechanism for addressing emissions at this time. If, after the Department reviews the collected data and newer technologies become available in the market, the Department determines that additional controls are warranted, the Department will work towards revising the regulation for blowdowns at that time.

Blowdown Threshold

Comment 125: Operators should be required to report in advance all blowdowns that will exceed 2500 standard cubic feet of gas (rather than the suggested threshold of 10000 SCF) (Commenters 2, 3, 4, 6-28, 31-34, 36-62, 65-69, 71, 73, 74, 76-83, 85, 87, 88, 93-132, 134-155, 159-162, 167, 170, 172, 174, 175, 177-192, 195, 196, 198-201, 204-216, 218-231, 233-235, 238, 239, 241-247, 250-254, 256-262, 264, 266-269, 271-283, 285-287, 291, 294, 296, 300, 301, 303-305, 308, 310-314, 317, 318, 320-324, 410, 411, 420, 421, 423, 427)

Comment 126: Require a lower threshold for blowdown notification and reporting. Notification and reporting threshold for both scheduled and unscheduled blowdowns should be lowered to 2500 SCF instead of the proposed 10,000. (Commenter 246, 284)

Comment 127: Lower the threshold for blowdown notification and reporting. (Commenter 193, 255, 407)

Comment 128: DEC should require total methane emissions from blowdown, not just those above the proposed threshold. Question how a seemingly arbitrary blowdown threshold of 10,000 scf was chosen. (Commenter 194)

Comment 129: While we support the Subpart W criteria for tracking and reporting blowdown emissions, a notification threshold of only four times high than the recordkeeping threshold is not reasonable. (Commenter 299)

<u>Response to comments 125-129:</u> The Department believes that a threshold of 10,000 scf ensures that there are adequate resources to evaluate and follow-up after each release event. The requirement is more

stringent than other states where the blowdown threshold is one million scf. As the Department collects and analyzes blowdown information it may find that a lower threshold is warranted and will propose revisions accordingly.

Blowdown notification

Comment 130: Require 48-hr or greater advanced notification to any Village Trustees/Town Board/City Council/County Legislature requesting it of all planned blowdowns, regardless of size, and other chemical releases. (Commenter 171)

Comment 131: Require at least 48 hours advance notification of all planned blowdowns and notification within 30 minutes of all unscheduled blowdowns, although we fully expect that the DEC will require blowdown capture for all planned blowdowns in its final rules. (Commenter 246)

Comment 132: For unplanned emergency blowdowns, we must have notification sent within 30 minutes not only to DEC and the host town of the emitting source but to all surrounding town officials. (Commenter 293, 439)

Comment 133: Require notification within 30 minutes of all unplanned blowdowns, regardless of size, and other chemical releases at all gas infrastructure facilities. (Commenter 171)

Response to comments 130 -133: Section 203-4.5 requires notification to the Department and appropriate local authorities forty-eight (48) hours in advance of a blowdown event and 30 minutes after an unplanned event; the notification will include: location, date, time and duration, contact person, reason for blowdown and estimated volume of release. These requirements, including the 10,000 cubic foot threshold, are more stringent than other regulatory efforts in capturing blowdown information. Maryland captures blowdown information using a threshold of one million cubic feet. The reason for the threshold is to ensure that the Department focuses on larger releases that have the potential to be of greater concern to the surrounding community while also considering industry reporting requirements. If, after the Department reviews the collected blowdown data, the Department determines that a different threshold or controls are warranted, the Department will work towards revising the regulation at that time.

Comment 134: Blowdown notification requirements are unnecessarily burdensome and unclear. The Coalition supports blowdown recordkeeping and periodic reporting, §203-4.5 imposes requirements for expedited notification for relatively small and common blowdowns. Neither the Proposed Rule nor the RIS explains the purpose or justification for these proposed expedited notification requirements. (Commenter 307)

Comment 135: Blowdown notification requirements are unnecessarily burdensome. Recommendations follow for reporting and recordkeeping, and a more appropriate threshold if notification is required. (Commenter 299)

Comment 136: supports blowdown recordkeeping and periodic reporting, but the Proposed Rule includes unreasonable and burdensome notification requirements that are not explained or justified in the RIS. (Commenter 299)

Comment 137: We recommend periodic reporting rather than notification requirements for the cumulative blowdown data. Annual reporting is recommended. (Commenter 299)

Comment 138: We recommend blowdown recordkeeping and reporting by event type for compressor stations and transmission pipelines consistent with GHGRP Subpart W criteria. (Commenter 299)

Comment 139: The regulation should establish a reasonable threshold for blowdown reporting and simplify the recordkeeping to satisfy DEC objectives while avoiding overly burdensome notifications. (Commenter 299)

Response to comment 134-139: The Department believes that the requirements in section 203-4.5 are necessary and are clear as written. The CLCPA, ECL Section 75-0105, requires that the Department develop a Statewide GHG inventory each year. The reporting requirement under section 203-4.5 will support that effort and help to inform if additional action is needed. This data will help the Department to understand when and how blowdowns occur and how to best reduce those emissions as needed in the future. See also response to comment 78.

Comment 140: The Department should clarify this issue (SCF vs. cubic feet) and explain the basis for engineering units other than SCF for the blowdown threshold. (Commenter 307)

Response to comment 140: The Department thanks you for this comment and has updated the express terms accordingly through non-substantive revisions to add clarity.

Comment 141: The RIS does not provide any environmental or health rationale for imposing requirements that are substantially more stringent than those required by the federal government under the EPA GHG Reporting Program or under pipeline safety regulations. In particular, the rulemaking materials fail to supply a reason for why the Department needs information that it is already receiving on gas releases so much faster and so much more frequently. Absent such a reason, there is not a justification for imposing the substantial burdens of expedited notifications on operators. These notification criteria would add considerable complexity and burden to operational requirements. (Commenter 307)

Response to comment 141: The Department disagrees. The RIS describes the rationale for imposing these requirements in its discussion of the ambitious requirements of the CLCPA. These requirements are outlined in the RIS and show the significant GHG emission reductions that New York must deliver. In addition, VOCs are precursor pollutants to ozone and New York remains in nonattainment for the ozone National Ambient Air Quality Standards. This regulation will be submitted as a SIP revision in support of the State achieving those standards.

Comment 142: If the blowdown requirements are retained, DEC should justify the costs and burden for operators to develop and implement systems that meet both the pre-notice obligation for planned events and immediate notice requirement for unplanned events. (Commenter 307)

Response to comment 142: The Department has retained the blowdown notification requirements and expects that regulated sources will meet the obligations to report. The Department will work with regulated sources and, if needed, develop instructions or guidance to support the timely reporting of these events.

Comment 143: With many notifications submitted monthly, the collective “information” could cause undue alarm, resulting in a misconception of risk. (Commenter 307)

Response to comment 143: The Department disagrees. The Department believes that there is value in real data shared with the public and will work to answer any questions the general public has regarding risk.

Comment 144: A recordkeeping and periodic reporting program would better serve DEC and other stakeholders, including operators. Establish blowdown recordkeeping and reporting by event type for compressor stations and transmission pipelines that is consistent with the criteria in Subpart W of the EPA GHG Reporting Program. This will develop blowdown data on events from physical volumes that exceed 50 cubic feet. Require periodic reporting rather than notifications for the cumulative blowdown data. Annual or semi-annual reporting is recommended. (Commenter 307)

Response to comment 144: Through the pre-proposal stakeholder process the Department heard loud and clear from New York residents that they want to know when both planned and unplanned blowdowns happen. As the commenter states, stakeholders may also review Subpart W data for other reporting information. While the Department believes that these requirements make sense for New York residents, it will also review the commenters suggested program to see if they may be made to align. If the Department believes a change should be made, it will propose changes to this rule in the future.

Comment 145: If notification is retained, we urge the Department to set a higher threshold for blowdown events. A threshold consistent with PHMSA incident notification criteria or regulations in other states is recommended. (Commenter 307)

Response to comment 145: The Department believes that the existing requirements will address stakeholder concerns. PHMSA incident notification criteria requires notification of an incident within 30 days.[12] The Department agrees with the stakeholder ask that a quicker notification is warranted and feasible. After the Department collects data through the blowdown reporting requirement it will determine if changes are warranted and propose accordingly.

Comment 146: It would be helpful to have a clearer delineation and categorization of "planned" event or "unplanned" events. The Coalition recommends categorizing very limited event types as "planned," such as periodic planned shutdown of a process or facility for maintenance. (Commenter 307)

Response to comment 146: The Department believes that the regulation is clear, if there is a blowdown event that the regulated source knows about in advance, then it is planned and the entity must report ahead of time. If the blowdown event occurred without prior knowledge, then this must be reported immediately after that event. The Department will work with regulated source owners/operators to provide answers should any questions arise.

Comment 147: Strengthen community notification requirements for planned and unplanned blowdowns (Commenter 243, 256, 288, 305, 423, 436)

Comment 148: Operators should notify DEC residents within 2500 feet of the facility, local and state officials and appropriate local emergency management officials depending on the severity of the incident (Commenter 243, 256, 305, 423).

Comment 149: Develop a community notification process for planned and unplanned blowdowns (Commenter 243, 256, 305).

Response to comments 147-149: The Department thanks the commenters for their suggestions. As the regulation is implemented, the Department will work with the regulated community to ensure that the reporting requirements as written are effective. If after receiving and analyzing the data, the Department does not believe them to be an effective tool for notifying the community, then it will evaluate proposing changes to Part 203 at that time.

Comment 150: Operators should be required to notify the DEC and all surrounding municipalities, first responders and residents. Given our current advanced state of technology, this level of notification is feasible. (Commenter 246)

Comment 151: Develop a framework for community notification for planned and unplanned blowdowns. (Commenter 255)

Comment 152: Require public awareness education and notification of planned and unplanned blowdowns. (Commenter 246)

[12] 40 CFR 171.16

Comment 153: The DEC should maintain a publicly accessible blowdown notifications on its website. (Commenter 246, 407)

Comment 154: Expand communication to ensure that impacted residents and community members receive timely notification of planned and unplanned blowdown events. (Commenter 193, 407)

Comment 155: The facility should be required to notify the public as Maryland recently required. Public notification should not be delegated to a local government but an operator's responsibility. (Commenter 284)

Response to comments 150-155: The Department will continue to work with communities, stakeholders and the regulated community to develop effective ways for this outreach.

Blowdown General

Comment 156: DEC should suspend planned blowdowns or other chemical releases when weather conditions would increase exposure to air pollutants. (Commenter 171)

Response to comment 156: The Department has not identified peer reviewed literature that informs under what conditions a blowdown should be suspended. Furthermore, there is no objective measure of stagnation that could be applied in this way. Pipeline gas is buoyant, so even during periods of poor atmospheric dispersion a blowdown is unlikely to result in high concentrations at ground level.

Comment 157: DEC should develop a maximum limit for planned blowdowns to ensure that if a planned blowdown emits more than is expected, operators will report these emissions and be held accountable for them. (Commenter 243, 256, 305).

Response to comment 157: Blowdowns typically occur for safety or repair reasons. The size of the blowdown is dependent on the type of equipment being repaired. The Department will continue to research options to limit blowdown emissions, including evaluation of all of the data collected for blowdowns data as required under section 203-4.5.

Comment 158: For 203-4.5 Pipeline or Compressor Station Blowdown, specify a time duration (e.g. during any twenty-four-hour period or per event) and volume as standard cubic feet units for blowdown. (Commenter 265)

Response to comment 158: Section 203-4.5 as written requires the reporting of time and duration of both planned and unplanned blowdowns.

Comment 159: Parts 203-4.5 and 4.6 require only an estimated volume of release from planned and unplanned blowdowns and pigging. CLCPA requires accurate GHG emissions inventorying so we need accurate measurements and reporting of such events. Such measurements are well within current technical capabilities of operators. There are many instances where calibrated flow measuring instruments are required and we suggest making use of such equipment mandatory in all instances where planned releases will occur, e.g. blowdowns and pigging. (Commenter 194)

Response to comment 159: Locating and fixing leaks to reduce methane and VOC emissions is the primary objective of Part 203. The Department further believes that the requirements for planned and unplanned blowdowns and pigging events are appropriate and sufficient to inform ongoing GHG inventory development for this sector. See also response to comment 78.

Tanks

Comment 160: Require higher storage vessel vapor control efficiencies and lower the 6 tpy VOC threshold for tanks. (Commenter 246)

Comment 161: Increase the efficiency requirement of tanks (installed prior to 2023) from 95% to 98% (Commenters 2, 3, 4, 6-28, 31-34, 36-62, 65-69, 71, 73, 74, 76-83, 85, 87, 88, 93-132, 134-155, 159-162, 167, 170, 172, 174, 175, 177-192, 195, 196, 198-201, 204-216, 218-231, 233-235, 238, 239, 241, 242, 244-247, 250-252, 257-262, 264, 266-269, 271-283, 285-287, 291, 294, 296, 300, 301, 303, 304, 306, 308, 310-314, 317, 318, 320-324, 410, 411, 420, 421)

Comment 162: Require higher storage vessel vapor control efficiencies (Commenters 256, 305, 423)

Comment 163: Require an increase from 95% to 98% which is achievable. (Commenter 246)

Comment 164: Vapor control unit efficiency requirement should be raised from 95% to 98% (Commenter 243, 254, 256, 303, 305, 423, 426, 431)

Comment 165: Lower the 6 TPY tank threshold to 2.7 TPY (Commenters 243, 256, 305, 423).

Comment 166: Require higher storage vessel vapor control efficiencies and lower the 6 tpy VOC thresholds for tanks. (Commenter 255)

Comment 167: A zero-emitting standard for new storage tanks with a PTE of 6 TPY or greater and new pneumatic controllers and pumps. (Commenter 203)

Response to comments 160-167: The existing 95% control efficiency will significantly reduce emissions from tanks. The Department is collecting data through the information collection provision for baseline reporting in section 203-10.1. If, after the Department analyzes the collected data, the Department determines that additional requirements for tanks are warranted, the Department will work towards revising the regulation at that time.

Comment 168: Recording of vapor control unit (VCU) efficiency should be added as a requirement (Commenter 243, 256, 305).

Response to comment 168: The Department does not believe that the recording of VCU efficiency is needed for a requirement at this time. The Department believes that the existing requirements will significantly reduce emissions while the Department collects data through the information collection provision for baseline reporting, 203-10.1 and LDAR reporting. If, after the Department reviews the collected data, the Department determines that additional controls are warranted, the Department will work towards revising the regulation.

Comment 169: Request that vapor control device (i.e. flare, enclosed combustion device) be allowed for situations where a sales gas or fuel gas system are available and it is not feasible to recover the storage vessel gas. Also allow the use of a vapor control device for applications where electric driven vapor recovery unit is not possible and the amount of emissions from an internal combustion engine driven VRU would be greater than the emissions from flaring the storage vessel vent gas. (Commenter 265)

Response to comment 169: The Department may consider feasibility of this recommended control under Subpart 203-9.

Comment 170: For facilities with a sales gas or fuel gas system, it may not be feasible (e.g. inadequate electricity supply, fuel gas for VRU engine) or economic to use a VRU. The feasibility of capture storage vessels (atmospheric storage tanks) vent gas using a VRU depends on several considerations. Some specific issues may be: (Commenter 265)

- The brine/produced water storage tanks used are typically made of poly plastic material that operate at atmospheric pressure and may replacing the standard poly plastic tank used with suitably equipped steel tank that uses thief hatches and pressure/vacuum (e.g. enardo) valves at a cost of $3,000 or more for steel tanks.
- The rate of vent gas discharged from the storage tanks (i.e. flash, standing and working losses) may not be technically or economically feasible.
- The VRU size would depend on the gas inlet pressure and discharge pressure need to inject the gas into an onsite booster compressor, fuel gas system or gathering/sales pipeline.
- A fuel gas system could be available, but there may not be a sales gas pipeline to receive the gas. This would require a flare or enclosed combustor to combust gas not used by the fuel gas system.
- There may be a lack of electricity for electric motor driven VRUs.
- For facilities using an IC engine powered VRU, the amount of fuel gas needed by the IC engine could exceed the volume of gas from venting the storage tank to the atmosphere.
- The BTU content of storage tanks holding crude oil or condensate can range from 1500 to 2500+ BTU/SCF. High BTU gas is not suitable for fuel in IC engines.
- Lack of nearby gas pipeline would also be a factor for sufficient fuel gas.
- The value of the vent gas that can be recovered may be much less than the cost of purchasing and operating a VRU system.
- Facilities need to use methods/technologies to prevent oxygen (air) from entering storage vent gas collected by a VRU adding cost and safety considerations.
-

Response to comment 170: The Department understands that there are challenges that regulated source owners will face in meeting the methane and VOC emission requirements of the rule. In addition, the Department does not expect storage vessels or tanks at smaller operations to trigger the 6 tpy VOC potential to emit threshold requiring VRU. All sources that do meet the threshold must comply with the requirements. See also response to comments 11-15.

Comment 171: The proposal states “with a potential to emit greater than or equal to six (6) tpy of volatile organic compounds (VOC)”. How is this measurement determined? (Commenter 64, 91)

Response to comment 171: The potential to emit from tanks may be calculated following standard inventory methods. Notably, EPA AP-42 contains emissions factors for tanks. The Department will work with the regulated community to provide technical assistance as necessary.

Pneumatic Devices

Comment 172: Require zero bleed pneumatic controllers for new facilities (Commenters 243, 255, 256, 305, 423, 426, 431)

Comment 173: Require zero-bleed pneumatic controllers for all facilities. (Commenter 246)

Comment 174: DEC should require that all new controllers utilize zero-emitting approaches, such as electric controllers, instrument air, etc. (Commenter 243, 256, 305).

Response to comments 172-174: The Department believes that the existing pneumatic device requirements are appropriate. The Department is collecting data through the information collection provision for baseline reporting in section 203-10.1. If, after the Department analyzes the collected data, the Department determines that additional controls for pneumatic controllers are warranted, the Department will work towards revising the regulation at that time.

Comment 175: Pneumatic devices requirements should be revised to be consistent with Subpart OOOOa. Pneumatic device emissions are relatively minor for T&S, so any deviation from the established federal requirements should be justified. Despite evidence showing that pneumatic devices account for a very small portion of methane emissions from the T&S segment, §203-4.2 imposes requirements on T&S segment pneumatic devices that exceed federal requirements in Subpart OOOOa. The RIS does not meet the requirement of SAPA §202-a 3(h) to explain or justify these additional requirements, such as annual vent rate measurement for existing continuous bleed devices, are not justified in the RIS. (Commenter 307)

Response to comment 175: Under the regulation each regulated source owner has an option of replacing a continuous bleed pneumatic device with either no bleed or intermittent bleed to eliminate the requirement to annually measure the vent rate on continuous bleed devices. Part 203 and all supporting documentation is fully compliant with SAPA. The RIS describes the rationale for imposing requirements, including the discussion regarding the ambitious emission reduction requirements of the CLCPA. These requirements are outlined in the RIS and show the significant GHG emission reductions that New York must deliver. Where the Department went beyond federal requirements the RIS cites federal regulatory uncertainty, ozone attainment issues, and CLCPA goals and requirements for the deviation.

Comment 176: For approval of delaying replacements, the Coalition recommends that the DEC adopt the approach in Subpart OOOOa, which does not require prior regulatory agency approvals, but does require the operator to identify and provide a rationale for use of such devices. Rather than retaining Proposed Rule requirements, the Coalition recommends following the Subpart OOOOa requirements for new, modified and reconstructed pneumatic devices, which EPA will very likely apply to existing devices in its upcoming rulemaking. (Commenter 307)

Response to comment 176: The Department understands that there may be safety concerns associated with waiting for a State Agency to provide approval for a delay of repair. The intention of this Subpart as described in the pre-proposal stakeholder process as well as in the RIS is to allow for real safety concerns to be addressed without harm to people or the environment. To clarify this intention, the Department has made a non-substantive revision through added language to Subpart 203-9 allowing delay of repair after documenting and submitting rationale to continue operation.

Comment 177: If the rule retains references to pneumatic device vent rates, we recommend that the requirement refer to the “vented emission rate” rather than the “natural gas flow rate.” (Commenter 307)

Response to comment 177: The Department agrees that “vented emission rate” better characterizes the activity and because it does not change the meaning of statement has made this non-substantive change in the express terms of Part 203.

Comment 178: Require replacement of existing gas-powered pneumatic controllers to zero bleed within the next two years, rather than only requiring new, replaced or retrofitted controllers to be zero bleed. (Commenter 203)

Comment 179: We recommend NY strengthen its requirements for gas-powered pneumatic controllers by adopting a rule modeled on a recently promulgated Colorado requirement. Per this rule, operators in Colorado must (1) ensure all new facilities are serviced by zero-emitting pneumatic controllers and (2) phase in zero-emitting pneumatic controllers at existing facilities over a two-year period. Per the Colorado rule operators must first survey their operations to determine what percentage of their existing wells use emitting controllers, and then craft and implement a plan to transition these facilities to zero-emitting devices by May 2023. (Commenter 203)

Response to comments 178 & 179: The Department believes that the requirements, as written in Part 203, for gas-powered pneumatic controllers are appropriate and that they will reduce emissions. The Department is collecting data through the information collection provision for baseline reporting in section 203-10.1. If, after the Department analyzes the collected data, the Department determines that additional controls for pneumatic controllers are warranted, the Department will work towards revising the regulation at that time.

Comment 180: Non-emitting devices using compressed air or electricity are widely available, and other states are requiring that new facilities utilize this technology whenever possible. Maryland mandates conversion of all continuous bleed natural gas pneumatic devices to “no-bleed” technology unless an exemption with requirements more stringent than Part 203 is granted. Colorado is requiring all new wells and compressor stations to use only non-emitting controllers, and retrofits at existing facilities are being phased in. The Department should adopt similar requirements for new facilities and institute a process for retrofits at current operations. (Commenter 284)

Response to comment 180: The Department believes that the requirements, as written in Part 203, are appropriate and that they will significantly reduce emissions. After the data collection requirements are met, the Department will review actual equipment counts to determine if further requirements are in order. The Department is aware of the other state programs and notes that the Maryland regulation is limited to five compressor stations while the Department has established requirements for every pneumatic device that may be servicing over 10,000 wells, thousands of metering and regulation stations, and over one hundred compressors within the State of New York.

Pigging Operations

Comment 181: Increase the frequency for reporting for pigging activities (Commenters 243, 256, 305, 423)

- Once per year is not sufficient to regularly evaluate emissions from this common activity or notify adjacent communities of nearby pipeline activities (Commenters 243, 256, 305, 423)
- Pigging activities should be treated like scheduled blowdowns and be subject to the same reporting schedule including prior notification to the DEC (Commenters 243, 256, 305, 423)

Comment 182: Require control of emissions during pigging operations. (Commenter 203).

- New York is leaving opportunities for emissions reductions on the table if it does not strengthen its pigging operations requirements. (Commenter 203)

Comment 183: Require increased reporting for pigging operations. (Commenter 246, 255)

Response to comments 181-183: The Department will collect data through this provision and through the information collection provision for baseline reporting in section 203-10.1. If, after the Department analyzes the collected data, the Department determines that controls for pigging are warranted, the Department will work towards revising the regulation at that time.

Comment 184: Operators should be required to adopt technologies to reduce emissions from pigging activities (Commenter 431).

Comment 185: Require the use of inert gases at pigging stations. (Commenter 171)

Response to comments 184-185: Because pigging has generally not been evaluated by EPA and control of emissions from pigging is not considered RACT, the Department believes that data collection is warranted first. If, after evaluating New York specific data and available technologies, the Department determines that further requirements are warranted it will work towards revising the regulations at that time.

Compressors

Comment 186: Maintain compressors at pipeline pressure where applicable to reduce the potential for gas leakage. (Commenter 122, 126, 171, 173, 306, 433, 437)

Response to comment 186: The Department does not believe that it has enough information to safely require specific pressures at compressor stations. As the Department continues to collect data and information, it will consider this comment for potential future proposals.

Comment 187: Require dry seals on all centrifugal compressors. (Commenter 171)

Response to comment 187: The Department has offered two options for wet seal centrifugal compressors per section 203-4.3; 1) convert to dry seal which would satisfy the recommendation of the commenter, or 2) collect the vapor that is released from a wet seal. If a regulated source chooses to not switch to dry seal, then it would be required to install vapor control equipment. Both solutions result in similar emissions reductions.

Comment 188: Commenter suggests the requirement of many technologies including: automatic air to fuel ratio (AFR) controls, oxidation catalysts and selective catalytic reduction (SCR) on exhaust stacks, dry low-NOx burners (DLNB), Low Emission Combustion (LEB), SCONOx, electrostatic precipitators, baghouses, scrubbers, plastic enamel sprays, electric or compressed air starters or actuators, electric motor compressors. (Commenter 171, 306)

Response to comment 188: The Department does not believe that it has enough information to require application of all of these technologies for this specific regulation. As the Department continues to collect data and information, it will consider this comment for potential future proposals. Furthermore, many combustion sources are subject to other state and federal requirements that sometimes incorporate the use of these control technologies. Moreover, relevant permit applications for combustion sources in the oil and gas sector are subject to the requirements of CLCPA Section 7. This may require the imposition of additional GHG mitigation measures at particular projects, which may include consideration of these control technologies.

Comment 189: Require vapor recovery technology for reciprocating compressors, storage tanks, and other sources of fugitive or vented compressor rods. (Commenter 171)

Response to comment 189: Vapor recovery and associated technology is required for storage tanks (Subparts 203-2 and 203-3) as well as reciprocating compressors and rods (section 203-4.4).

Comment 190: Require zero-emission dehydrators and similar closed-system technology to avoid venting of gas. (Commenter 171)

Response to comment 190: The Department does not believe that it has enough information to require the application of this technology. As the Department continues to collect data and information, it will consider this comment for potential future proposals.

Comment 191: Compressor wet seals should be measured at normal operating temperature and pressure. (Commenter 243, 256, 305)

Response to comment 191: Part 203-4.3(d) states that wet seals shall be measured at normal operating temperature.

Comment 192: At facilities that use reciprocating engines/compressors or other leak-prone equipment, vapor recovery should be a basic requirement. (Commenter 306).

Response to comment 192: Vapor recovery and associated technology is required for reciprocating compressors and rods in section 203-4.4.

Comment 193: The rule should add flexibility by allowing the operator to elect to follow Subpart OOOOa requirements for rod packing emission mitigation. (Commenter 307)

Response to comment 193: Adding this flexibility would be inconsistent with the intended goals of the rule. As written, the requirements for rod packing are more stringent and more in line with the goals and requirements of the State under the CLCPA. Addressing leakage by changing of rod packing based on hours run does not address leakage resulting from unforeseen issues.

Comment 194: Reciprocating compressor requirement should be clarified and should not include duplicative requirements for addressing leaks (via LDAR) and from the rod packing "seal." Section §203-4.4 outlines ambiguous and possibly unnecessary mitigation requirements for T&S segment compressor stations. It is not clear why both "compressor rod packing" and "compressor seal" are referred to in §203-4.4 (c). (Commenter 307)

Comment 195: If DEC envisions another vent source other than the rod packing that is subject to §203-4.4 (c), then we urge the Department to define that source more clearly so it can be differentiated from the rod packing and from compressor components subject to LDAR. (Commenter 307)

Comment 196: For centrifugal compressor seals subject to seal-based requirements, the final rule should include an exemption from LDAR analogous to the exemption for reciprocating compressor rod packing in §203-4.4(b). (Commenter 307)

Comment 197: The final rule should more precisely define the sources of interest, including: (1) compressor-related components subject to LDAR, which should exclude centrifugal compressor seals; (2) the degassing vent for centrifugal compressors with wet seals; and (3) dry seals and wet seals (separate and distinct from the wet seal degassing vent), associated emissions for each source, and mitigation options for each source. (Commenter 307)

Comment 198: The proposed rule should leverage the NSPS OOOOa definition of a component that excludes rod packing and compressor seals. (Commenter 299)

Response to comment 194 - 198: The Department believes that the requirements, as written, are appropriate and not ambiguous. While the requirement for measurement addresses specific rod packing and compressor seal leakage, LDAR will identify other potential leaks associated with compressor activities.

Comment 199: The recordkeeping and "certification" requirements associated with compressor operations and vent measurement are overly prescriptive and would essentially be mandated for all units, because a compressor station operator cannot be sure that a compressor will be running on the scheduled measurement day. Streamlined records can be maintained that ensure measurements are completed on a timely basis. (Commenter 307)

Response to comment 199: The Department does not believe that the requirements are overly prescriptive; the language offers a standard method common to the industry. However, the Department also recognizes that new and innovative technology is being introduced into this field and is open to discussing alternatives and improved methods with regulated source owners to understand if revisions may be necessary at some point in the future.

Comment 200: The Coalition recommends additional discussion on centrifugal compressors so that we can collectively better understand the sources, associated emissions, flawed EPA data that over-estimates emissions from wet seal degassing vents, and reasonable and rational emissions management approaches. (Commenter 307)

Response to comment 200: The Department is available to discuss and to review research and data with stakeholders. If it determines, based on this review, future revisions should be made to Part 203, it will work to propose those revisions at that time.

Comment 201: There is a potential NSPS OOOO and OOOOa compliance conflict with the proposed Part 203 requirements for reciprocating compressors rod packing or seal emissions. Part 203 allows for the reciprocating compressor to limit the leak to 2 scfm and EPA's NSPS OOOO/OOOOa would require rod backing seals to be replaced every 26,000 hours of operation or 36 months. (Commenter 265) see page 13

Comment 202: The requirements for emissions from reciprocating compressor rod packing and centrifugal compressor seals should be clarified and consistently applied for both compressor types. (Commenter 299)

Response to comment 201 & 202: The Department understands that NSPS OOOOa includes a time and hours of operation requirement. The Department believes that the limit of leakage requirement in Part 203 will catch potential upset leaks quicker than the EPA requirements. In addition, New York's CLCPA requires significant Statewide reductions in GHG emissions and this requirement is one way that the Department is addressing the required reductions. Furthermore, if a facility is subject to both Part 203 and the NSPS, it will be subject to both sets of requirements.

Comment 203: At least one production operation within New York State has a landfill methane recovery plant delivering natural gas to a field compressor. This landfill methane is combined with produced natural gas and transported to a pipeline. How do we handle the compressor controls/monitoring of this combined operation? (Commenter 265)

Response to comment 203: If the compressor is part of the transmission pipeline as defined in section 203-1.3, then the compressor is subject to the requirements set forth in Subpart 203-4.

Comment 204: In Express Terms Summary (Page 3 of 9) change "Reciprocating Compressors have the following requirements (compressors that operate fewer than 200 hours over a rolling twelve (12) month period)" to read "Reciprocating Compressors have the following requirements (compressors that operate equal to or more than 200 hours over a rolling twelve (12) month period.)" (Commenter 265)

Comment 205: The Council believes that the "fewer than" included in this threshold should actually be "greater than." (Centrifugal/Reciprocating compressors pg. 2/3). (Commenter 243, 256, 305)

Response to comments 204 & 205: The Department thanks the commenters for identifying this typographical error in the summary. The Department has corrected this.

Comment 206: Require a leak mitigation stop-gap measure during the 18 months wet-seal to dry-seal conversion time frame for compressor stations. (Commenter 246, 255)

Comment 207: Require a leak mitigation stopgap measures during the 18-month wet seal to dry seal conversion time frame. Either drastically reduce the conversion time frame or include a stopgap requirement so that the leaking seal isn't potentially allowed to leak for up to 18 months. A provision to capture interim mitigation measures should be added in addition to the replacement. The Council urges the DEC to add a stopgap measure requirement to mitigate these emissions as soon as possible and attempt to make the conversion to a dry seal within 3 months. (Commenters 243, 256, 305, 423)

Response to comments 206-207: The Department believes that the existing requirements will significantly reduce emissions while the Department collects data through the information collection provision for baseline reporting, 203-10.1. If, After the Department reviews the collected data, the Department determines that additional controls are warranted, the Department will work towards revising the regulation.

Compliance

Comment 208: There are not enough qualified testers in our area to meet the needs of the required twice a year testing and then, if necessary, it will be difficult for the tester to return for repairs (Commenters 63, 70, 75, 84, 89, 90, 158, 163-165, 168, 169, 176, 237, 240, 325-379, 382, 384-404, 412-418, 441-444, 446, 447, 448, 450, 451)

Response to comment 208: The Department has not received any documentation or evidence that demonstrates that there are not enough qualified testers. If there are well documented issues with the number of qualified testers that affect the ability of regulated entities to comply with the regulation, it can be addressed at that time.

Comment 209: Require compliance of these regulations by non-combustion emission sources and those considered exempt in DEC regulation. (Commenters 122, 126, 171, 173, 290, 433, 437)

Response to comment 209: Part 203 does require compliance for non-combustion sources and those sources that may have historically not been subject to other regulatory requirements.

Comment 210: Producing oil wells do not make a lot of gas, what should well owners do with the gas that is made? For operators that have no other method of using small amounts of associated gas, flaring should be required as an option instead of venting. Some solutions include:

- Require electricity providers to take generated power at a certain minimum price as has been done in the past. This is not being done much today because electric distribution companies will only pay the lowest avoided fuel cost. Distribution companies should be required to pay a producer close to the retail price of electricity. (Commenters 156, 157, 166, 405)
- Low-cost access points should be provided to producers to sell electricity. (Commenters 156, 157 & 405)
- Access points should be provided by pipeline companies to take small quantities of gas. (Commenter 156, 157 & 405)
- Bitcoin mining should be approved as a use for stranded gas. (Commenter 156, 157 & 405)

Response to comment 210: The Department does not believe that it has enough information to address these suggestions at this time. As the Department continues to collect and review data and information, it will consider this comment when and if it looks at future revisions of the regulation

Comment 211: If the state proceeds with the proposed new regulation for stripper wells the state needs to provide a path with suitable and affordable methods to use or dispose of methane and VOCs. (Commenter 156, 157 & 405)

Response to comment 211: The Department believes that if a well is emitting for more than six months triggering the requirements of the regulation, no matter the well type, it is the responsibility of the source owner to determine how best to comply with respect to the individual well attributes.

Comment 212: Ensure compliance by establishing robust inspection and/or auditing processes. (Commenter 193)

Comment 213: Require onside verification of regulatory and permitting compliance by independent registered inspectors through scheduled and random visits. (Commenter 171)

Comment 214: Require an inspection and/or auditing process to ensure compliance with the regulations, at a minimum annual inspections, by DEC inspectors. Require substantial penalties for violations. (Commenter 246)

Comment 215: Establish an inspection and/or auditing process to ensure compliance with the regulation. (Commenter 255)

Comment 216: The fact that wells have a significantly lower potential to emit, which is acknowledged, should be reflected in testing requirements. (Commenter 295)

Comment 217: Develop an inspection and auditing plan specific to the natural gas infrastructure covered in these rules as a means to verify compliance with these regulations. Plan should include a minimum of annual inspections by DEC inspectors (Commenters 243, 256, 305, 423)

Response to comments 212-217: The Department does not believe that it is necessary to require duplicate inspections by consultants or by DEC inspectors. The Department will track the reported results that come from compliance submittals. As the Department continues to collect and review data and information, it will consider this comment when and if it looks at future revisions of the regulation

Comment 218: DEC should clarify the information that must be included in the baseline report. (Commenter 243, 256, 305)

Response to comment 218: The Department lists all of the components to be included in the baseline report in subdivision 203-10.1(c). The Department is looking to develop an electronic reporting form, reporting guidance/instructions and is available to answer questions that the regulated community may have.

Comment 219: The January 1, 2023 compliance date is reasonable for new installations however may not be feasible for existing facilities that need to undergo capital improvements to comply with the proposed provisions. Commenters three compressors at a storage facility will need to be modified to meet the provisions of proposed 203-4.4(d) and funds must be budgeted for engineering, design, and procurement; equipment and contractors must be secured using competitive bidding practices; and timed outages of the compressors must be coordinated to maintain the operability of the facility. Suggest that the compliance date for all new vapor collection devices required by proposed Subpart 203-8 be set at January 1, 2024 with provisions for time extensions approved by the Department based on showing of good faith effort by the impacted entities. Another commenter suggested an extended compliance date phased-in glidepath commensurate with the complexity of conformance by individual operators. (Commenter 249, 270, 319)

Response to comment 219: The Department understands that challenges may arise with respect to components or services and that is why Part 203 offers flexibility through the delay of repair provisions in the regulation. The Department further believes that the existing compliance dates are critical for achieving the emissions reductions under the regulation.

Repair

Comment 220: Require stricter deadlines for repair on all infrastructure (Commenters 2, 3, 4, 6-28, 31-34, 36-62, 65-69, 71, 73, 74, 76-83, 85, 87, 88, 93-132, 134-155, 159-162, 167, 170, 172, 174, 175, 177-192, 195, 196, 198-201, 204-216, 218-231, 233-235, 238, 239, 241-244, 245, 247, 250-252, 256-262, 264, 266-269, 271-283, 285-287, 291, 294, 296, 300, 301, 303-305, 308, 310-314, 317, 318, 320-324, 410, 411, 420, 421, 423, 426, 427, 431, 432)

Comment 221: Operators should be required to repair severe leaks within two days, medium-sized leaks within five days and 14 days for smaller leaks (Commenters 243, 256, 305, 423)

Comment 222: DEC should replace the 30-day blanket requirement on repair times and require operators to repair leaks within 2 to 14 days (Commenter 431).

Comment 223: Repairs should be undertaken within 5 days of detection and severe leaks should be repaired much sooner than has been allowed (Commenters 426, 427).

Comment 224: DEC should also include significance thresholds for leaks that necessitate even more rapid repairs (Commenter 243, 256, 305).

Comment 225: The timing for repairs is too long and not consistent. Measures to reduce emissions are not required until January 1, 2023 and some repairs are allowed eighteen months while others are allowed thirty days. It is recommended that requirements begin July 1, 2022 and that be given 6 months for required repairs with a proposed 12-month grace period. (Commenter 194)

Response to comments 220-225: The Department worked with many stakeholders and industry experts during the pre-proposal stakeholder period. Through that work, the Department set different repair and replacement deadlines in the regulation that it believes to be feasible. The Department set these timeframes to reduce the potential for delay of repair requests. As it continues to collect and review information and data, the Department will consider shorter repair time requirements in future revisions of the regulation.

Comment 226: DEC should include a provision requiring the operator to maintain an inventory of back-up components where economically feasible (Commenter 243, 256, 305).

Response to comment 226: The Department disagrees. There are a variety of types of components in this sector and it is currently infeasible for the Department to develop a comprehensive list of all parts needed as additional inventory for backup.

Comment 227: Page 4 of 10 references a study “Carbon Limits, Statistical Analysis of Leak Detection and Repair in Europe, November 2017” to support a statement that 31% of repairs were ineffective and therefore required follow up monitoring. This study is based on 3 companies repairs of compressors, transfer stations and storage facilities. Most of the data came from one source and contained no information on wells. This study is clearly does not relate to well LDAR. (Commenter 295)

Response to Comment 227: The Department used literature sources which were available and peer-reviewed to develop the supporting documents for Part 203. While the location and sources may not match exactly, the Department believes that the literature demonstrates that not all repairs in this sector are successful and it illustrated the need for follow-up.

Emissions

Comment 228: The technical papers referenced by NYSDEC are focused on well sites that are larger producing wells or that may not be representative of well sites in New York State in reference to the public hearing on 3/26/2021. (Commenter 265)

- Cited data from “New Mexico Permian Basin Measured Well Pad Methane Emissions are a Factor of 5-9 Times Higher Than US EPA Estimates,” October 2020, Anna M. Robertson, et al. This information seems to be used as a basis for the proposed rule. The facilities that were the basis for the paper’s results are not representative of New York wells for the following reasons: Delaware Basin production rates of natural gas and oil rates were much higher than New York State gas and oil wells. (Commenter 265)
- The RIS references the paper “Statistical Analysis of Leak Detection and Repair in Europe,” November 2017 does not contain data on wells or pipelines. Compressor stations comprised 62.4% of the data points and 30% are a combination of transfer stations, storage facilities or LNG facilities. None of the leak monitoring measured the quantity of emissions but measured leak concentration and estimated flowrate based on USEPA Method 21. (Commenter 265)

Comment 229: We have found the studies used to determine the possible VOC emissions are based on wells and techniques used outside of NYS and don't reflect the way our personal well operates (Commenters 63, 70, 75, 84, 86, 89, 90, 158, 163, 165, 168, 169, 240, 325-380, 384-403, 412-418, 441-444, 446, 447, 448, 450, 451)

Response to comments 228-229: The Department relied on available data and research to determine potential impacts from wells in New York. Some of the data included conventional wells similar to those in New York. To enhance our understanding of New York's system, the Department included section 203-10.1 in this rulemaking, to collect that additional data.

Comment 230: Require Lowest Achievable Emissions Rate (LAER) technology at all new and existing oil and gas infrastructure facilities including those not designated under Title V requirements or not located within non-attainment areas. (Commentor 126, 171, 173, 248, 306, 429, 437)

Response to comment 230: The Department is not currently aware of the existence of information for approved LAER at oil and gas facilities. The Department will continue to track best practices and other data to determine if LAER should be included in future revisions.

Comment 231: Incorporate stack emission thresholds for VOC and other harmful pollutants that would establish statewide BAT for specific infrastructure (Commenters 243, 256, 305, 423)

Comment 232: The regulation should be based on the most recent and best available emissions information from natural gas operations. (Commenter 299)

Comment 233: DEC should not save specific combustion BAT requirements for a future regulation but should act now to ensure the greatest possible emission reductions. (Commenter 243, 256, 305)

Comment 234: Require stack emissions regulations for engines and turbines that would establish statewide Best Available Technology (BAT). (Commenter 246, 255, 407)

Response to comments 231-234: The Department believes that the existing requirements are appropriate and will significantly reduce emissions. If, after the Department reviews the collected data, the Department determines that the formal development of BAT is warranted, the Department will work towards revising the regulation.

Comment 235: The New York State Oil and Gas Sector Methane Emissions Inventory (July 2019) indicates that production operations contribute 1.5% of all emissions to that inventory. With the production (upstream) portion being so low, why do the regulations place a large burden on wells compared to transmission lines, storage, compressors and distribution? (Commenter 265)

Response to comment 235: Part 203 does not place a larger burden on production wells compared to transmission lines. The LDAR requirements for wells are less stringent and there are fewer components covered.

Comment 236: Provisions apply to sources with a potential to emit of 6tpy of VOCs or an emission rate of 6 or 3 or 2 scfh of VOCs or methane. We question these seemingly arbitrary thresholds. If these are attempts to conform to business as usual with respect to existing state or federal practice, for example the EPA CTG, then we strongly suggest that DEC exert leadership and connect reduced thresholds to milestones in planned GHG reductions demanded by the CLCPA. Will emissions at these rates hinder our meeting those milestones? (Commenter 194)

Response to comment 236: The Department reviewed available studies and data to determine the thresholds in the regulation. The data was collected from multiple states and synthesized in peer-reviewed journal articles. The Department selected thresholds based on the State's emissions reduction requirements and ability to enforce while understanding that the requirements must also be achievable to ensure reliable distribution of natural gas to end users. While this effort began before the enactment of the CLCPA, it will support the much larger and multi-faceted requirements of the CLCPA.

Moreover, while the adoption of Part 203 is consistent with the CLCPA requirement to reduce Statewide GHG emissions across all sectors by 40% from 1990 levels by 2030, and by 85% from 1990 levels by 2050, the Department recognizes that additional measures will be necessary. That is, beyond the adoption of Part 203, additional regulatory actions will be necessary, including measures recommended in the Draft Scoping Plan, to ensure the achievement of the CLCPA's Statewide GHG emission limits.

Comment 237: Any differences in an NYS rule should only consider the incremental emissions reduction that would be achieved when considering benefits and justifying the need for a different regulation. (Commenter 307)

<u>Response to comment 237:</u> The Department disagrees. While the program is more stringent than EPA's current regulation, the reductions that are achieved through this regulation will support the goals and requirements of the CLCPA, as well as have additional benefits as described in the RIS.

Costs

Comment 238: Costs exceeds the value of production (Commenters 63, 70, 75, 84, 86, 89, 90, 133, 158, 163, 165, 168, 169, 197, 202, 240, 315, 316, 325-379, 381, 384-403, 409, 412-419, 441-444, 446, 447, 448, 450, 451)

Comment 239: The projected fees of a qualified tester testing and possibly having to repair a leak are prohibitive for a single well owner like ourselves (Commenters 63, 70, 75, 84, 89, 90, 91, 158, 163, 165, 168, 169, 240, 325-380, 384-403, 412-418, 441-444, 446, 447, 448, 450, 451)

Comment 240: The proposed requirement to report to two additional DEC divisions is an extra burden and cost to our fixed income (Commenters 63, 70, 75, 84, 89, 90, 158, 163, 165, 168, 169, 240, 325-379, 384-403, 412-418, 441-444, 446, 447, 448, 450, 451)

Comment 241: The new proposed regulation would be unable to be financially provided. (Commenter 237)

Comment 242: Commenter states that the proposed regulation will not be economically viable for small business or single-use wells for several reasons (Commenter 91):

- Commercial operators have well maintenance technicians on staff to make minor repairs at cost while homeowners or small businesses would be forced to hire a specialty plumber to repair minor leaks which would be more expensive. (Commenter 91)
- Most owners of self-use natural gas wells are homeowners or small business owners who likely lack the expertise to properly or cost-effectively implement Part 203 (example, determine if small brine tank emits 6tpy of VOC). This sets up homeowners and small businesses to fail. (Commenter 91)
- A homeowner or business who assumes the responsibility of a well which is no longer commercially viable is extending the life of the well and conserving the resource by maximizing recovery of natural gas from the reservoir. (Commenter 91)
- Since self-use wells do not generate revenue, the rule will likely force some homeowners or small businesses to prematurely plug their self-use well, this is not an efficient use of resource. This homeowner or small business will then be required to find another source of energy to meet their demand, which may be less clean, and the resulting impacts should be evaluated and factored into the Department's decisions. (Commenter 91)

Comment 243: Too much expense as taxes and approaching retirement age. (Commenter 133)

Comment 244: Adding this large extra layer of expense to oil leases with stripper wells does not make sense and is not cost effective for the producer or the regulating agency. It seems that more energy will be consumed and wasted, and emissions created than prevented for low production wells. (Commenter 156, 157, 405, 406)

Comment 245: Our well should had no control by NYSDEC, so why should we have to pay for and be obligated to you for anything. (Commenter 383, 419)

Response to comments 238-245: Part 203 was developed to reduce greenhouse gas and VOC emissions in a meaningful yet feasible way. The Department noted the cost to well owners in the rule support documents and depending on well throughput some wells will cost more per unit output to meet the requirements.

Comment 246: Table 2: (page 7 of 10) Summary of Potential Costs has the Annual Cost High of LDAR for wells as $1,053,385. (page 6 of 10) has the ICF estimated annual cost of well LDAR as $2,006. There are ~ 10,600 wells in NYS. 10,600 times $2,006 equals $21,263,600, a significant difference from $1,053,385. (Commenter 295)

Response to comment 247: The ICF study estimated an annual cost based on groupings of wells and the table in the Regulatory Impact Statement represents these groupings.

Social Cost of Carbon

Comment 248: I believe the cost breakdown of the new 6 NYCRR Part 203 may be inaccurate. (Commenter 1)

Comment 249: Greater consideration should be given to the methodology by which the social cost of methane (SCM) is calculated, as it may alter the proposal's benefit-cost ratio as well as infrastructure and monitoring requirements for the oil and natural gas sector. (Commenter 1)

Comment 250: I argue these costs are based on a flawed methodology. I believe these costs are underestimated, although recent studies have shown that they may be overestimated as well. (Commenter 1)

Comment 251: It does not adequately incorporate air quality related impacts intrinsic to the chemistry of methane. Being that these impacts are not included, the DEC's cost of methane per metric ton is misguided, and therefore it is not an accurate measure of true SCM. Rather, the DEC's methodology calculates SCM by converting methane into its carbon dioxide equivalent and multiplying by the SCC. This does not take into account the dynamics of methane that create externalities unlike carbon. For example, methane has been strongly linked to declining agricultural yields; a point not considered when carbon equivalent is based solely on global warming potential. (Commenter 1)

Comment 252: A study supporting this environmental economic SCM methodology concluded that the true cost may be closer to $2,400 per metric ton at a 5% discount rate, $3,600 per metric ton at a 3% discount rate, and $4,060 per metric ton at a 2.5% discount rate. (Commenter 1)

Comment 253: I suggest the DEC revise their cost analysis to incorporate a wider breadth of related factors. (Commenter 1)

Response to comments 248-253: The Department believes that the methodology behind the value of methane is the most appropriate approach for estimating the societal damage of methane emissions. The methodology was developed by the federal Interagency Working Group and its calculations are widely accepted by the scientific and economic communities. This methodology does not take the carbon dioxide equivalent of methane and multiply it times the social cost of carbon, an approach that is against the recommendations in DEC's Value of Carbon Guidance under the CLCPA, rather it uses integrated assessment models to develop estimates of the social cost which are more accurate than using the global warming potential. A range of research suggests the true value of the damage of methane emissions could be either lower or higher than the value used by New York, therefore at this time DEC believes maintaining consistency with the proven methodology developed by the Interagency Working Group and reflected in DEC's Value of Carbon Guidance is the most appropriate approach.

Technology

Comment 254: There are several items to consider for a Grower Co-op: (Commenter 92)

- If convert natural gas boilers to green electricity, one quarter of all grape vineyards will need to be taken out of production.
- If Village municipal electric system power is used, the Co-op will use all Village energy production.
- If Co-op converts to all electricity, the Village will have to entirely rewire its electrical distribution system.

Response to comment 254: Part 203 was developed to reduce methane and VOC emissions in a meaningful yet feasible way. The Department noted the cost to businesses in the Regulatory Flexibility Analysis for Small Businesses and Local Governments and understand that depending on well throughput there may be some challenges in meeting the requirements.

Comment 255: I am hopeful that you allow parties to use other technologies that can reach the same goals while creating products that will benefit the CLCPA. (Commenter 236)

Response to comment 255: Part 203 allows for alternative and innovative methods for detection of leaks in Subpart 203-7.

Comment 256: Could there be a way for DEC staff to check for leaks the same way fire department, utility, etc., staff test for gas, radon or other substances? (Commenter 315, 409)

Response to comment 256: The Department does not currently have the staff to perform every leak detection requirement across New York State, however, the Department may spot check sources.

Definitions

Comment 257: Component (4): To avoid confusion, we recommend that DEC adopt the approach to "component" used in the NSPS, Subpart OOOOa rule, which excludes rod packing and compressor seals. Duplicative LDAR and other requirements should not apply to rod packing and compressor seals. there is no way to perform LDAR on the bulk of well casing that is below ground. (Commenter 299, 307)

Response to comment 257: The Department believes that the rule, as written, is clear, appropriate and is consistent with what has been used in other natural gas regulations in other states. As such, the Department does not believe the suggested revisions are necessary.

Comment 258: Condensate (5): The definition should clarify which streams/segments are affected (e.g., does it apply to upstream operations or to underground storage?) and reference to "surface separation" should be revised or defined. (Commenter 299, 307)

Response to comment 258: Part 203 is clear that it applies to above ground activities. The Department believes that the existing definition is sufficient.

Comment 259: Critical Component (7) and Critical process unit (8): The definitions and criteria are ambiguous. The conceptual approach to categorizing components or processes regarding repair schedules adds significant and unnecessary ambiguity and complications to LDAR repair (and delay-of-repair) schedules. (Commenter 307)

Response to comment 259: The Department understands from previous stakeholder feedback that there must be some leeway for critical components to ensure reliable production and delivery. Therefore, Part 203 includes critical component and process unit definitions to allow for more flexibility in repairs.

Comment 260: Centrifugal compressor seal (2): This definition appears to focus on the mechanical seal for centrifugal units. The references to wet seal degassing vent emissions and "component" versus "seal" requirements are unclear and/or duplicative. (Commenter 307)

Comment 261: Reciprocating natural gas compressor seal (34): The definition of seal-/rod-packing versus the definition of components subject to LDAR need to be clarified to ensure mitigation requirements are clear and not duplicative. (Commenter 307)

Comment 262: Fuel gas system (12): The definition is confusing because "fuel gas" typically refers to combustion equipment but the definition refers to "actuated equipment," which implies the context is pneumatic devices. The definition and its applicability and uses within other rule sections should be clarified and revised accordingly. (Commenter 307)

Comment 263: Natural gas transmission compressor station (20): The segment boundary should be clearly defined. The definition should also clarify what is included within the station boundary versus equipment associated with the pipeline (e.g., pipeline M&R stations in proximity to a compressor station). (Commenter 307)

Response to comments 260-263: The Department believes that the definition, as written, is clear, appropriate and is consistent with what has been used in other natural gas regulations in other states. As such, the Department does not believe revisions are necessary.

Comment 264: Pigging (26): The definition refers to "implements." The term should either be revised to use a different term (e.g., "instruments") or removed. (Commenter 307)

Comment 265: Vapor control efficiency (46): Should be identified as definition (46) not (465). (Commenter 307)

Response to comments 264& 265: The Department thanks the commenters for catching these typographical errors. The Department has made non-substantive revisions to correct these errors in the final rule.

Comment 266: Add a definition of "Marginal and Low Producing Oil and Gas Wells." Offer the following definition: "Marginal and low producing oil and gas wells are those that produce less than or equal to 15 barrels of oil equivalent (BOE) per day." Both the IRS and EPA used 15 BOE as a threshold. (Commenter 265)

Response to comment 266: While the EPA CTG allows for an exemption for lower producing wells, the Department has not adopted any exemptions for Part 203. Furthermore, the Department has evaluated and accepted the studies which define super-emitters. Studies suggest that methane emissions are underestimated from this sector based on atmospheric research.[13,14] This underestimation may be due to super-emitters which represent a small fraction of sites but may be responsible for a large fraction of emissions. Many studies support this phenomenon[15,16,17,18] and it serves as a large part of the basis behind the Department proposal to cover all affected sources in New York State and not exempt the smaller sources as EPA and other states do. Based on New York State data, if the Department adopted a threshold such as that adopted by EPA and other states, over 95% of wells would be exempt from the requirements of this rule and the estimated emissions reductions and benefits would be reduced. See also response to comments 38 and 94-97.

Comment 267: Does the definition of "natural gas gathering and boosting station" (definition 19) include a compressor located/operating at a single well pad site? The definition of well site (definition 49) describes the location and not the type of equipment (e.g., well head, separators, heaters, storage vessels, dehydration units, compressors) that can be located/operated at a single well site. (Commenter 265)

Comment 268: Does the definition for "natural gas gathering and boosting station" include multiple compressors (two or more) located at a single well pad site that has multiple wellheads at a well pad. (Commenter 265)

Response to comments 267 & 268: If the compressor is located at a well site and is part of a gathering and boosting station, that compressor would be subject to the requirements of compressors at gathering and boosting stations in Subpart 203-3.

Comment 269: Request new definition for "Oil and Natural Gas Activities" as used in 203-2. This request is made because it is unclear if compressors located at a "well site" is excluded from the controls and measurement. Definition for "well site" is location based and not based on the type of equipment that might operate at a well site. (Commenter 265)

Comment 270: Does the "well site" definition include oil and gas production equipment such as wellheads, line heaters, separators, heater treaters, glycol dehydration units and storage tanks, compressors, pumps, generators (not an inclusive list)? (Commenter 265)

Comment 271: Does the "well site" definition apply to well pads that include multiple wellheads at the same cleared area? (Commenter 265)

Response to comments 269-271: The requirements for oil and natural gas well sites are defined in Subparts 203-2 and 203-7. Those Subparts list which components at a well site are subject to requirements. The Department has updated Subpart 203-7 to clarify that both wellheads and components are subject to those requirements. Since all wellheads are subject to the requirements of Part 203 there is no need to distinguish the difference between a cleared area containing one or multiple wellheads.

Comment 272: Change 203-1.3 Definitions (24) "Oil" to read "means 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 gas." (Commenter 265)

---

[13] Brandt, A.R., et al. 2014. Methane Leaks from North American Natural Gas Systems. Science. Vol. 343.
[14] Miller, S.M., et al. 2013. Anthropogenic Emissions of Methane in the United States. Proceedings of the National Academy of Sciences. December 10, 2013.
[15] Brandt, A.R., et al. 2014. Methane Leaks from North American Natural Gas Systems. Science. Vol. 343.
[16] Lamb, Brian K, et al. 2015. Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States. Environmental Science & Technology.
[17] Zavala-Araiza, Daniel, et al. 2015. Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites. Environmental Science & Technology.
[18] Zimmerle, Daniel J., et al. 2015. Methane Emissions from the Natural Gas Transmission and Storage System in the United States. Environmental Science & Technology.

Response to comment 272: This definition is consistent with other Department regulations and the "API" has been assumed for many years. Because it does not change the meaning of the definition, the Department will add the API to Part 203 for clarification purposes.

Comment 273: Request that definition of "Pneumatic Pump" not include piston type pneumatic pumps that use natural gas. NSPS OOOOa and the 2016 CTG for Oil and Gas state that these are inherently low emitting devices. (Commenter 265)

Response to comment 273: The Department believes that the definition, as written, is clear, appropriate and is consistent with what has been used in other natural gas regulations in other states. As such, the Department does not believe revisions are necessary.

Comment 274: Request that the definition of "Reciprocating natural gas compressor" specifically state that the definition does not include vapor recovery units (VRU) that use non-segregated reciprocating compression (i.e. power and compression cylinders driven by the same common crankshaft). (Commenter 265)

Response to comment 274: The Department believes that the definition, as written, is clear, appropriate and is consistent with what has been used in other natural gas regulations in other states. As such, the Department does not believe revisions are necessary.

Comment 275: Specify in the definitions that standard conditions for oil and gas operations is 60 degrees Fahrenheit and 14.7 psia. This is consistent with 40 CFR Subpart W and 40 CFR Subpart A, 98.6 Definitions. (Commenter 265)

Response to comment 275: The Department agrees that 60 degrees Fahrenheit and 14.7 psia represents standard conditions.

Comment 276: (b)(3) "City Gate" requires additional clarification to address the intended purpose of describing a point of delivery from a gas pipeline operator/transmission system operator to a distribution system operator. NGA suggests the following revised definition for consideration by the Department: (Commenter 270, 319)

- "City Gate" means a point or measuring location where custody transfer occurs between a natural gas transmission system pipeline company/operator (or "supplier") and a distribution system company/operator (or "Local Distribution Company (LDC)") (Commenter 270, 319)

Response to comment 276: Based on this comment the Department has updated the definition of "City gate" in Part 203 to clarify the definition. The updates are non-substantive and do not represent a change in the intended meaning.

Comment 277: If DEC intends LDAR requirements for metering stations to apply to components beyond the meter itself, we recommend that it consider the following revisions to the definition of "metering station": "(17) "Metering Station" means a **station** ~~device~~ designed for the continuous **measurement** ~~and simultaneous analysis~~ of the quantity ~~and quality~~ of natural gas being transported in a pipeline **and may include simultaneous analysis of natural gas quality.** (Commenter 299, 307)

Comment 278: (b)(17) "Metering Station" requires additional clarification to address the intended purpose of describing a facility, typically in conjunction with a regulation station, where natural gas is continuously monitored for quality and quantity upstream of the custody transfer point. This clarification would help eliminate confusion as to applicability to downstream distribution system operators that may share metering or monitoring signals from upstream of the custody transfer demarcation point within a facility. Suggested change:

- "Metering Station" a facility with device(s) intended to measure the quantity and/or monitor the quality of natural gas upstream of a custody transfer demarcation point. (Commenter 270, 319)

Response to comments 277 & 278: Based these comments the Department has updated the definition of "Metering Station" in Part 203 to clarify the definition. The updates are non-substantive and do not represent a change in the intended meaning.

Comment 279: (b)(19) "Natural gas gathering and boosting station" requires additional clarification to eliminate confusion in applicability downstream of custody transfer (aka "city gate"). The current proposal states that such a station includes "…all equipment and components associated with moving natural gas to a natural gas processing plant, transmission pipeline, or distribution pipeline." It does not seem feasible that a facility normally considered a "gathering and boosting station", as the term is normally used in the oil and gas industry would be directly connected to a local distribution system. It would be less confusing if the Department were to clarify the definition in the following manner:

- "Natural gas gathering and boosting station" means all equipment and components associated with moving natural gas to a natural gas processing plant, or transmissions pipeline, or distribution pipeline. (Commenter 270)

Response to comment 279: Based this comment the Department has updated the definition of "Natural gas gathering and boosting station" in Part 203 to clarify the definition. The update is non-substantive and does not represent a change in the intended meaning.

Comment 280: The express terms contain several undefined phrases that could be misinterpreted to expand the scope of the rule to include equipment owned and operated by utilities that distribute gas to residential and commercial end-users. "Distribution center and "distribution pipeline" are used in several definitions in the proposal.   (Commenter 249)

Comment 281: (b)(21) "Natural gas transmission pipeline" requires additional clarification to eliminate confusion in applicability associated with distribution system operator custody transfer demarcation points. NGA understands the Department's desire to adopt a definition parallel to recent proposals by DPS and Federal Gas Safety Regulations. However, for the purposes of this rulemaking, the proposed regulation does not define the meaning of the term "distribution center" so it is not clear if the Department is referring to a transmission pipeline custody transfer point (aka "city gate") that connect a transmission pipeline to a local distribution company. In the context of this proposal, the LDC's believe it is imperative to further define the term "Distribution Center" to avoid confusion in applicability. The proposed definition is similar to that of the Gas Pipeline Safety Advisory Committee (GPAC):

- "Distribution Center" means the demarcation point where gas piping used primarily to deliver gas to customers who purchase it for consumption, for example, at City Gate metering and or/pressure reduction custody transfer location(s) that define a gas franchise territory." (Commenter 270, 319)

Response to comments 280 & 281: The Department believes that the definition, as written, is clear, appropriate and is consistent with what has been used in other natural gas regulations in other states. As such, the Department does not believe revisions are necessary.

Comment 282: There are portions of the pipelines owned by utilities that distribute gas to residential and commercial end-users and downstream of the citygate that exceed the hoop stress criteria as proposed in 203-1.3(b)(21)(ii). To eliminate any ambiguity in the final rule, we propose a new subdivision (b) be added to Section 203-1.1 that states: "This Part does not apply to distributing gas utilities or to equipment and components located downstream of a citygate." (Commenter 249, 270, 319)

Response to comment 282: The Department agrees and notes that throughout the stakeholder process and in the RIS, the Department has stated that Part 203 covers components up to the city gate but not beyond. The Express Terms reflect the clarification.

Miscellaneous

Comment 283: We have owned our well since 1997 and have never seen a DEC inspector look at our well. There the DEC may not have good information/data to support that wells such as ours are releasing VOCs other than extremely low quantities. Therefore, no action at all may be needed. (Commenter 202)

Comment 284: There are existing regulations in place requiring wellhead pipe fittings and valves to control and contain oil and gas at the well head and these should be sufficient to contain and control any oil and gas coming from the well. (156, 157 & 405)

Response to comments 283 & 284: The Department has a regulation in place, Part 556, which addresses releases from wells. More specifically:

- 556.1(b) which is specific to oil wells states: "All oil wells capable of production shall be equipped with wellhead controls adequate to properly contain the control and flow thereof."
- 556.2(b) which is specific to gas wells states: "No gas from any gas well, except such as is produced in a clean up period not to exceed 48 hours after any completion or stimulation operation, plus that used for the controlled testing of a well's potential in a period not to exceed 24 hours, plus that used in any operational requirements, shall be permitted to escape into the air. Extensions of these time periods shall be granted administratively by the department upon application therefor by the owner or operator and the demonstration of sufficient good cause."
- 556.2(c), which is specific to gas wells states: "All gas wells capable of production shall be equipped with wellhead controls adequate to properly contain the control and flow thereof."

However, there are no specific methods defined in the existing requirements and it is well known that leak detection methods have demonstrated that leakage does occur. The Department believes that by requiring specific leak detection methods and testing, leaks will be identified, repaired and methane and VOC emissions will be reduced.

Comment 285: It looks like the Biden Administration is going to offer money to plug old wells, NY should utilize these funds. In addition to wells without an owner, the state should offer to pay producers for voluntarily plugging wells that are no longer viable. The cost of plugging plus a couple of thousand. (Commenter 156, 157 & 405)

Response to comment 285: New York is one of the oil and gas producing states that has been preparing for potential funding of orphaned oil and gas well plugging as part of the current U.S. Congressional budget negotiations. The language of the current draft legislation does not contemplate addressing wells that are owned/operated by active well owners/operators. It is focused on the universe of orphaned oil and gas wells which, by definition, do not have identifiable operators or owners.

Comment 286: When will NYSDEC supply a document that includes the inventory report format and all required data fields for the baseline report? (Commenter 265)

Response to comment 286: The Department has been working on developing a method and format for submittal. The Department anticipates releasing these shortly after Part 203 becomes final.

Comment 287: Requests for the opportunity for the public and industry representatives to review and comment on the reporting format and data fields prior to promulgation. (Commenter 265)

Response to comment 287: The Department met with IOGANY and other stakeholders during the pre-proposal phase of this rulemaking to discuss data fields and reporting. The Department considered all stakeholder feedback in the development of Subpart 203-10.

Comment 288: There should be a caption associated with Table 1 of the Regulatory Impact Statement Summary that notes that although 100-yr CO2e figures are shown, the proposed regulations conform to the CLCPA mandate to use the 20-yr CO2e figures. This table lacks an entry for a current estimate for statewide VOC emissions; Table 1 of the Regulatory Impact Statement does show an entry for latest inventory of VOC emissions. (Commenter 194)

Response to comment 288: The table lists both 100-yr and 20-yr global warming potential. State Administrative Procedures Act requirements state that the summary document must be 2000 words or less. The Department believes that it has retained as much required information in the summary as necessary and appropriate and within the confines of the required 2000 word maximum.

Comment 289: The DEC did not provide us with notification of the proposed regulation. We have checked with other operators in our vicinity and were informed that they did not receive DEC notification either. As stakeholders we feel we should have been given notice. Notification would have been easy because your Department has been communicating with us electronically. (Commenter 202)

Response to comment 289: The Department complied with all notice requirements in its proposal of Part 203. SAPA § 202 lays out the notice requirements that the Department must comply with during the rulemaking process. These requirements include submitting a notice of proposed rulemaking to the Secretary of State for publication in the State Register and affording the public an opportunity to submit comments on the proposed rule. In addition to the requirements of SAPA, the Division of Air Resources also complied with the hearing requirement found in ECL § 19-0303(1). Notice of proposed rulemaking for Part 203 were published in the State Register and on the Department's website on May 12, 2021. Hearings for Part 203 were held on July 20, 2021 at 2pm and 6pm. The public comment period was from May 12, 2021 to July 26, 2021. In addition to these formal notice and comment opportunities, the Department also provided many opportunities for consultation with stakeholder throughout the rulemaking process.

Comment 290: I don't know what an API number is. (Commenter 419)

Response to comment 290: The API (American Petroleum Institute) number is a unique number assigned to every oil and gas well.

Comment 291: How will Part 203 impact small operators like myself? (Commenter 72)

Response to comment 291: Part 203 will require that you perform leak detection and repair. Part 203 was developed to reduce greenhouse gas and VOC emissions in a meaningful yet feasible way. The Department noted the cost to businesses in the Regulatory Flexibility Analysis for Small Businesses and Local Governments and understand that depending on well throughput there may be some challenges in meeting the requirements.

Beyond the Scope

Comment 292: Require air monitoring for key VOCs and PM 2.5 to capture the spikes that occur. The DEC should send alerts to municipalities in real time so that they can notify residents of spikes and urge vulnerable populations to stay indoors with windows closed (Commenters 2, 112, 122, 147, 173)

Comment 293: DEC should quickly develop rules to apply to natural gas-fired power plants and any other gas-related infrastructure not covered by these rules (Commenters 3, 4, 6-28, 31-34, 36-62, 65-69, 71, 73, 74, 76-83, 85, 87, 88, 93-132, 134-155, 159-162, 167, 170, 172, 174, 175, 177-192, 195, 196, 198-201, 204-216, 218-231, 233-235, 238, 239, 241, 242, 244, 245, 247, 250-252, 257-262, 264, 266-269, 271-283, 285-287, 291, 294, 296, 300, 301, 304, 308, 310-314, 317, 318, 320-324, 410, 411, 420, 421)

Comment 294: We urge the Department to extend the applicability of these regulations to gas-fired power plants and other end-user combustion facilities, or to promulgate similar rules for them as soon as possible. (Commenter 306)

Comment 295: DEC should not be permitting any more gas facilities (Commenter 439).

Comment 296: Chain of custody records and tracking for all industrial waste removed from gas infrastructure facilities. (Commenter 171)

Comment 297: The rule needs to be applied to private industries as well, such as those that would use a power plant for Bitcoin mining (Commenter 430).

Comment 298: We want to encourage renewable energy in New York State. We do not want imported hydro from Canada. (Commenter 434)

Comment 299: Need continuous emission monitoring for particulate matter as well as for BTEC gases and chemicals. (Commenter 438)

Response to comments 292-299: The proposed rule only applies to emissions of VOCs and Methane from the oil and gas sector. These comments are beyond the scope of this rulemaking.

Number	Name
1	Erik Anderson
2	Susan Van Dolsen
3	Hal Pillinger
4	Beverly Simone
5	Fred Schloessinger
6	Enid Cardinal
7	Michael Gorr
8	Pamylle Greinke
9	Andrea Zinn
10	Ken Baer
11	A.L. Steiner
12	sarah apflel
13	Beth Darlington
14	Paula Clair
15	David Bly
16	William Forrest
17	Richard Stern
18	Aileen McEvoy
19	jennifer valentine
20	Jerry Rivers
21	Shirley Schue
22	Peggy Alt
23	Edward Rengers
24	Christine Schmitthenner
25	c s
26	Keith Said
27	Mary Thorpe
28	Brian Truax
29	Clementine Zawadzki
30	Maek Pezzai
31	Deborah Porder
32	Patricia Irish
33	Nada Khader
34	Juanita Dawson-Rhodes
35	Susan D. Multer, MSW, MS
36	stan scobie
37	Clare Chollet
38	Nivo Rovedo
39	Susan Zeiger
40	Bhikkhu Bodhi
41	Hal Smith
42	M. Doretta Cornell
43	N. Dumser
44	Sandra Sobanski
45	Susanna Levin
46	Chris Saia
47	Aaron Fumarola
48	Gerald Kline
49	Wayne Chang
50	Elizabeth Schwartz
51	Larysa Dyrszka
52	Carl Gutman

Number	Name
53	JK Kibler
54	Tsu Ku Lee
55	Hal Smith 2
56	Rebecca Berlant
57	Kenneth Baer
58	Lalita Malik
59	Doug Couchon
60	Nivo Rovedo 2
61	YI-HSIN CHEN
62	Candice Martin
63	Debora & Donald Waddell
64	Cody Corke
65	Michelle Solomon
66	Laurie Evans
67	Marian Nangle
68	Diane Bozzetto
69	steve hopkins
70	Tim Coleman
71	Iris Arno
72	Thomas Kranz
73	Cristina Ortiz
74	Martha Michael
75	Town of Chautauqua
76	anjarew ettinger
77	Leslie Guttman
78	Amy Rosmarin
79	steve hopkins 2
80	steve hopkins 3
81	marlene h. wertheim
82	Janine Kourakos
83	Pam Pooley
84	Andrew & Athanasia Landis
85	John Sullivan
86	Amy Brinkley
87	David Carpenter
88	Krystal Ford
89	East Aurora Union Free School District
90	Jonathan Geiger
91	Chautauqua County DPF
92	Growers Co-op Grape Juice Co.
93	Lori A Robinson
94	Lori Robinson 2
95	Marc Robinson
96	Jennifer Horowitz
97	Jack Gorman
98	Mary Krieger
99	Marie McRae
100	Sharon Michales
101	Hodiah Nemes
102	Jerry Rivers 2
103	Deborah Margoluis
104	Lauren Porosoff

Number	Name
105	Ben van Buren
106	arthur kuypers
107	Alice Slater
108	Flo Brodley
109	Avery Svensgaard
110	Jessica Thompson
111	Nancy Kasper
112	miriam hoffman
113	Grace Nichols
114	Jane Rothman
115	steve Hopkins 4
116	Mirabai Marquardt
117	Amanda Gotto
118	Linda Snider
119	Charles Brexel Sr.
120	Nivo Rovedo 3
121	Susan Domina
122	Ann Glazer
123	Lauren Brois
124	Frank Regan
125	Elizabeth Lynch
126	Iris Marie Bloom
127	Bernice Gordon
128	Doug Bullock
129	Jerry Rivers 3
130	Kevin Costa
131	Doug DellaPietra
132	Robert K. Camera - City of Geneva
133	Stanley A. Morris
134	Donna Yannazzone
135	Karen Kaufmann
136	Ellen Hollander
137	Amlin Gray
138	Jennifer Murphy
139	Jay Gilbert
140	Richard Schlosberg
141	Maria Gagliardi
142	Maria Harris
143	Kirsten Andersen
144	Judith Edelstein
145	Dorian Fulvio
146	David Glass
147	Tina Lieberman
148	Arnold Gore
149	Rich Kellman
150	Linda Hoffmann
151	Gabriele Conway
152	French Conway
153	Susan Rutman
154	Nancy Drain
155	Jacqueline Lhoumeau
156	Greg Thropp -Copper Ridge Oil

Number	Name
157	Greg Thropp -Copper Ridge Oil 2
158	Jamestown Plastics Inc
159	Erin Zipman
160	Jerry Ravnitzky
161	Ann van Buren
162	M Leybra
163	Paul N Lepp
164	Alan Gustafson
165	Patricia M. Mance
166	Stephen L. Ford- Vertical Energy, Inc
167	Diane Torstrup
168	H. Olsen & Sons, Contr. Inc.
169	Donald C. Ring
170	Carla Rae Johnson
171	Harriet Cornell
172	Irene Weiser
173	Mark Pezzati
174	Jeffrey O'Donnell
175	Lisa Bambino
176	Jennifer Dye
177	John McIntyre
178	janet olshansky
179	Lauren Gaudio
180	FRANCES SNEDEKER
181	Norma and Braun
182	Marietta Scaltrito
183	Douglas Cooke
184	Joseph Quirk
185	Sandra F. Kaplan
186	Patricia Hansen
187	Laura Shapiro
188	Amanda Smock
189	Dennis Vecchiarello Sr
190	sasha silverstein
191	Yvonne Taylor
192	Tracy Griswold
193	Westchester County Board of Legislators
194	Tompkins County Legislature
195	Fern Stearney
196	Nicholas Prychodko
197	Depew Union Free School District
198	Lisa Derrickson
199	John Gallagher
200	Wendy Fast
201	Richard Kite
202	Frank and Carol Shattuck
203	Environmental Defense Fund
204	Thomas Giblin
205	Linda Grassia
206	Chris Stoscheck
207	Wes Ernsberger
208	Marie Garescher

Number	Name
209	Lynn Reichgott
210	Katherine Collett
211	Lauren Kirkwood
212	Ann Mallozzi
213	Chris Durante
214	Carol Hinkelman
215	Linda Ng
216	Linda Ng 2
217	Marthe Schulwolf, Ph.D.
218	Matthias Von Reusner
219	Judith Zingher
220	Rachel Cohen
221	steve Hopkins 5
222	marianne deluca
223	MARGARET BRADBURY
224	Susan Holland
225	Daniel Lefkowitz
226	Vitalah Simon
227	Sandra Selikson
228	Elizabeth LoGiudice
229	Lisa Montanus
230	Harriet Shugarman
231	Peggy Kurtz
232	Dr. Lori Kent
233	Edward J Berry
234	Jo Salas
235	Rebecca McCartney
236	John Broyles
237	Connie Miller
238	Ann Finneran
239	Chana Friedenberg
240	Shirley Wright
241	Midge Iorio
242	Kay Reibold
243	John Lord
244	Patricia Tanguy
245	David Carpenter 2
246	Grassroots Environmental Education
247	Adrienne Paule
248	Sandra Steingraber, PhD
249	Consolidated Edison Company
250	Monique Weston
251	Mary Krieger 2
252	Thomas Hirasuna
253	Diana Strablow
254	Gale Pisha
255	City of Peekskill
256	Chris Burdick Assemblymember. 93rd District
257	Judith Edelstein 2
258	Jonathan Nash
259	C Zawadzki

Number	Name
260	Esther Racoosin
261	Cynthia Loewy
262	Jonathan Dudley
263	Gerri Wiley
264	Jennifer Greenidge
265	The Independent Oil and Gas Association of New York (IOGANY)
266	Michele Temple
267	Ginger Comstock
268	Laura Neiman
269	David Rosenfeld
270	Northeast Gas Association
271	Marvin Stamm
272	Todd Fellerman
273	Perry Ross
274	David Carpenter 3
275	Karl Gesslein
276	Amy Rosmarin 2
277	Megan Dyef
278	John Keiser
279	Will Meyerhofer
280	Nancy N Brothers
281	Linda Lefkowitz
282	Jerry Rivers 4
283	Mary E Ludington
284	Assembly members Steve Englebright & Dan Quart
285	Jean Chambers
286	Don Lieber
287	Mary Antonakos Cottingham
288	Town of North Salem
289	Consumer Energy Alliance (CEA NY)
290	Senator Peter B. Harckham
291	Nancy Stamm
292	Alliance for a Green Economy
293	Suzannah Glidden
294	John Papandrea
295	Empire Energy E&P, LLC
296	Larry Forsblad
297	Senator Shelley Mayer
298	Assemblywoman Sandy Galef
299	Williams
300	Ken Fellerman
301	Sarah Forsblad
302	Pramilla Malick
303	Linda Reik
304	Kurt Haumesser
305	Clean Air Council
306	Otsego 2000
307	NY Reliable Energy Infrastructure Coalition
308	Mark Mansfield
309	Town of North Salem 2

Number	Name
310	Barbara VanHanken
311	Rachele Aives
312	Rita Faulkner
313	Katherine Korten
314	Nawan Bailey
315	Vicki L Hitchcock
316	Curt Meeder
317	Emily Siegel
318	Annette Gilson
319	National Grid
320	Patricia Parkhurst
321	meg kettell
322	Priscilla Auchincloss
323	nancy schulman
324	Claudia Nagy
325	Michael Pinzok
326	Fred Croscut
327	Judith Caldwell
328	Yvonne C. Smith
329	Peter Steimle
330	Howard J. Depriest
331	James Dickman
332	James Surdej
333	Harold Burgard
334	Robert E. Norris
335	Robert D. Pecuch
336	Andrew & Athanasia Landis
337	Christine Mroz-Baier
338	Kenneth Thompson
339	Bryan Champlin Sr.
340	Tim Mascorella
341	Aaron W. Zimmerman
342	Charles H. Johnson
343	Gary H. Nobbs
344	Michael Hanselman
345	Brian R. Rapp & Judith E. Rapp
346	William Harris
347	Jospeh Janusz
348	James Renaldo
349	Hank Miller
350	Dennis G. Czarniak
351	Patricia J. Crossley
352	Joseph P. & Sandra K. DeJoe
353	Grover H. Riefler
354	Roger Dunnewold
355	Kevin Abbaj
356	Donald A. Ames
357	Stanley A. Morris
358	Raymond & Jean Balcerzak
359	Kenneth A. Goater
360	Norm Bromley Sr.
361	Eve Zukowski

Number	Name
362	Lyle Lewis
363	Thomas E. Leone
364	Frederick H. Smith
365	Nicole Kellogg
366	Ryan Olson
367	Randy L. Schwartz
368	Connie S. Miller
369	Bruce Tenpas
370	Donald Waddell
371	Thomas A. Hockran
372	Richard R. Rogers
373	Donald Williams
374	Jeff McCaskey
375	Tim Thompson
376	Debora Milliman & Lee Milliman
377	Eden VFW Post 8265
378	Angeline Liminello
379	William Berner
380	Amy Brinkley
381	Michael J. Lischer
382	Doris R. Kirsch
383	William & Lucille Frost
384	Michael J. Lischer- 2
385	Richard Senske
386	Patricia B. Pecuch
387	Richard Wattles
388	Donald W. Juli
389	Gene Brian Demambro
390	Thomas J. Deacon
391	Jonathan & Suzan George
392	Carole Stevens
393	Joyce E. Wyllys
394	Jennette Kent
395	Donald Orr Jr.
396	Winfield Densmore
397	Judith Hunt
398	Steven Greene
399	Donald L. & Janice L. Bartlett
400	J. Skrzynskz
401	Paul R. Gebhard
402	Douglas Wicks
403	Douglas Wicks-2
404	Donald Emhardt
405	Greg Thropp
406	Stephen L. Ford
407	Westchester County Board of Legislatures
408	6 signatures comments about small businesses
409	Vicki L. Hitchcock
410	Mark Mansfield 2
411	Karen Kucharski
412	Donald J. Donovan

Number	Name
413	Fred Croscut
414	Stan Kwilos
415	Paul N. Lepp
416	Michael R. Muffoletto
417	Richard J. Wittmeyer
418	David W. Resetarits
419	Ann Foss
420	Maritza Fitzgerald
421	Maritza Fitzgerald 2
422	Ellen Weininger
423	Matt Walker
424	Amy Rosmarin
425	Lisa Harrison
426	Jacquelyn Dreschler
427	John Sullivan
428	Joel Kupferman
429	Sandra Steingraber
430	Mary Finneran
431	Nadia Steinzor
432	Ruth Walter
433	Matt Salton
434	Catherine Skopic
435	Michel Lee
436	Susan van Dolsen
437	Niva Rovedo
438	Pramilla Malick
439	Suzannah Glidden
440	Ann Finnerman
441	Patrick J Conklin
442	Mark C Henry
443	Kathleen Belles
444	Kyle Anderson
445	Gary Mazurkiewicz
446	James E. Bauer
447	Cheryl C. George
448	Ronald Klock
449	Paul Gebhard
450	Arthur and Ann Foss
451	Howard C. Ellis
452	Terry Brocklebank
453	Daniel F Smith