CLEAN AIR ADVOCATES'
EXHIBIT 1

JOINT PROPOSED AMENDMENTS TO PROPOSED 20.2.50 NMAC FROM

ENVIRONMENTAL DEFENSE FUND

AND

CONSERVATION VOTERS NEW MEXICO, DINÉ C.A.R.E., EARTHWORKS, NATURAL RESOURCES DEFENSE COUNCIL, SAN JUAN CITIZENS ALLIANCE, SIERRA CLUB, 350 NEW MEXICO, AND 350 SANTA FE

AND

CENTER FOR CIVIL POLICY AND NAVA EDUCATION PROJECT

TITLE 20 ENVIRONMENTAL PROTECTION
CHAPTER 2 AIR QUALITY (STATEWIDE)
PART 50 OIL AND GAS SECTOR – OZONE PRECURSOR POLLUTANTS

20.2.50.1 ISSUING AGENCY: Environmental Improvement Board.
[20.2.50.1 NMAC – N, XX/XX/2021]

20.2.50.2 SCOPE: This Part applies to sources located within areas of the state under the board's jurisdiction that, as of the effective date of this rule or anytime thereafter, are causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more department monitors. Once a source becomes subject to this rule, the requirements of the rule are irrevocably effective unless the source obtains a federally enforceable air permit limiting the potential to emit to below such applicability thresholds established in this Part.
[20.2.50.2 NMAC – N, XX/XX/2021]

20.2.50.3 STATUTORY AUTHORITY: Environmental Improvement Act, Section 74-1-1 to 74-1-16 NMSA 1978, including specifically Paragraph (4) and (7) of Subsection A of Section 74-1-8 NMSA 1978, and Air Quality Control Act, Sections 74-2-1 to 74-2-22 NMSA 1978, including specifically Subsections A, B, C, D, F, and G of Section 74-2-5 NMSA 1978 (as amended through 2021).
[20.2.50.3 NMAC - N, XX/XX/2021]

20.2.50.4 DURATION: Permanent.
[20.2.50.4 NMAC - N, XX/XX/2021]

20.2.50.5 EFFECTIVE DATE: Month XX, 2021, except where a later date is specified in another Section.
[20.2.50.5 NMAC - N, XX/XX/2021]

20.2.50.6 OBJECTIVE: The objective of this Part is to establish emission standards for volatile organic compounds (VOC) and oxides of nitrogen (NO_x) for oil and gas production, processing, and transmission sources.
[20.2.50.6 NMAC - N, XX/XX/2021]

20.2.50.7 DEFINITIONS: In addition to the terms defined in 20.2.2 NMAC - Definitions, as used in this Part, the following definitions apply.

A. "Approved instrument monitoring method" means an optical gas imaging, United States environmental protection agency (U.S. EPA) reference method 21 (RM21) (40 CFR 60, Appendix B), or other instrument-based monitoring method or program approved by the department in advance and in accordance with 20.2.50 NMAC.

B. "Auto-igniter" means a device that automatically attempts to relight the pilot flame in the combustion chamber of a control device in order to combust VOC emissions, or a device that will automatically attempt to combust the VOC emission stream.

C. "Bleed rate" means the rate in standard cubic feet per hour at which natural gas is continuously or intermittently vented from a pneumatic controller.

D. "Calendar year" means a year beginning January 1 and ending December 31.

E. "Centrifugal compressor" means a machine used for raising the pressure of natural gas by drawing in low-pressure natural gas and discharging significantly higher-pressure natural gas by means of a mechanical rotating vane or impeller. Screw, sliding vane, and liquid ring compressor is not a centrifugal compressor.

F. "Closed vent system" means a system that is designed, operated, and maintained to route the VOC emissions from a source or process to a process stream or control device with no loss of VOC emissions to the atmosphere.

G. "Commencement of operation" means for an oil and natural gas wellhead, the date any permanent production equipment is in use and product is consistently flowing to a sales lines, gathering line or storage vessel from the first producing well at the stationary source, but no later than the end of well completion operation.

H. "Component" means a pump seal, flange, pressure relief device (including thief hatch or other opening on a storage vessel), connector or valve that contains or contacts a process stream with hydrocarbons, except for components where process streams consist solely of glycol, amine, produced water or methanol.

I. **"Connector"** means flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, "T's" or valves) to each other; or a pipe line to a piece of equipment; or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this Part.

J. **"Construction"** means fabrication, erection, installation or relocation of a stationary source, including but not limited to temporary installations and portable stationary sources.

K. **"Custody transfer"** means the transfer of oil or natural gas after processing or treatment in the producing operation, or from a storage vessel or automatic transfer facility or other processing or treatment equipment including product loading racks, to a pipeline or any other form of transportation.

L. **"Control device"** means air pollution control equipment or emission reduction technologies that thermally combust, chemically convert, or otherwise destroy or recover air contaminants. Examples of control devices include but are not limited to open flares, enclosed combustion devices (ECDs), thermal oxidizers (TOs), vapor recovery units (VRUs), fuel cells, condensers, air fuel ratio controllers (AFRs), catalytic converters (oxidative, selective, and non-selective), or other emission reduction equipment. A control device may also include any other air pollution control equipment or emission reduction technologies approved by the department to comply with emission standards in this Part.

M. **"Department"** means the New Mexico environment department.

N. **"Downtime"** means the period of time when equipment is not in operation, or when a well is producing, and the control device is not in operation.

O. "**Drilling**" or "**drilled**" means the process to bore a hole to create a well for oil and/or natural gas production.

P. **"Drill-out"** means the process of removing the plugs placed during hydraulic fracturing or refracturing. Drill-out ends after the removal of all stage plugs and the initial wellbore cleanup.

Q. **"Enclosed combustion device"** means a combustion device where gaseous fuel is combusted in an enclosed chamber. This may include, but is not limited to an enclosed flare, reboiler, and heater.

~~P~~R. **"Existing"** means constructed or reconstructed before the effective date of this Part and has not since been modified or reconstructed.

S. **"Flowback"** means the process of allowing fluids and entrained solids to flow from a well following stimulation, either in preparation for a subsequent phase of treatment or in preparation for cleanup and placing the well into production. The term flowback also means the fluids and entrained solids flowing from a well after drilling or hydraulic fracturing or refracturing. Flowback ends when all temporary flowback equipment is removed from service. Flowback does not include drill-out.

T. **"Flowback vessel"** means a vessel that contains flowback.

~~Q~~U. **"Gathering and boosting station"** means a permanent combination of equipment that collects or moves natural gas, crude oil, condensate, or produced water between a wellhead site and a midstream oil and natural gas collection or distribution facility, such as a storage vessel battery or compressor station, or into or out of storage.

V. "**Hydraulic fracturing**" means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale, coal, and tight sand formations, that subsequently require flowback to expel fracture fluids and solids.

W. "**Hydraulic refracturing**" means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

~~R~~X. **"Glycol dehydrator"** means a device in which a liquid glycol absorbent, including ethylene glycol, diethylene glycol, or triethylene glycol, directly contacts a natural gas stream and absorbs water.

~~S~~Y. **"Hydrocarbon liquid"** means any naturally occurring, unrefined petroleum liquid and can include oil, condensate, and intermediate hydrocarbons.

~~T~~Z. **"Liquid unloading"** means the removal of accumulated liquid from the wellbore that reduces or stops natural gas production.

~~U~~AA. **"Liquid transfer"** means the loading and unloading of a hydrocarbon liquid or produced water between a storage vessel and tanker truck or tanker rail car for transport.

~~V~~BB. **"Local distribution company custody transfer station"** means a metering station where the local distribution (LDC) company receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

~~W~~CC. "Natural gas compressor station" means one or more compressors designed to compress natural gas from well pressure to gathering system pressure before the inlet of a natural gas processing plant, or to move compressed natural gas through a transmission pipeline.

~~X~~DD. "Natural gas-fired heater" means an enclosed device using a controlled flame and with a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.

~~Y~~EE. "Natural gas processing plant" means the processing equipment engaged in the extraction of natural gas liquid from natural gas or fractionation of mixed natural gas liquid to a natural gas product, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

~~Z~~FF. "New" means constructed or reconstructed on or after the effective date of this Part.

GG. "Occupied area" means (1) a building or structure designed for use as a place of residency by a person, a family, or families. The term includes manufactured, mobile, and modular homes, except to the extent that any such manufactured, mobile, or modular home is intended for temporary occupancy or for business purposes; (2) indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities; (3) five thousand (5,000) or more square feet of building floor area in commercial facilities that are operating and normally occupied during working hours; and (4) an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of outdoor public assembly.

HH. "Pre-production operations" means the drilling through the hydrocarbon bearing zones, hydraulic fracturing or refracturing, drill-out, and flowback of an oil and/or natural gas well.

~~AA~~II. "Operator" means the person or persons responsible for the overall operation of a stationary source.

~~BB~~JJ. "Optical gas imaging (OGI)" means an imaging technology that utilizes a high-sensitivity infrared camera designed for and capable of detecting hydrocarbons.

~~CC~~KK. "Owner" means the person or persons who own a stationary source or part of a stationary source.

~~DD~~LL. "Permanent pit" means a pit used for collection, retention, or storage of produced water or brine and is installed for longer than one year.

~~EE~~MM. "Pneumatic controller" means an instrument that is actuated using pressurized gas and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow, and temperature.

~~FF~~NN. "Pneumatic diaphragm pump" means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

~~GG~~OO. "Potential to emit (PTE)" means the maximum capacity of a stationary source to emit an air contaminant under its physical and operational design. The physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and a restriction on the hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is federally enforceable. The PTE for nitrogen dioxide shall be based on total oxides of nitrogen.

~~HH~~PP. "Produced water" means a fluid that is an incidental byproduct from drilling for or the production of oil and gas.

~~II~~QQ. "Produced water management unit" means a recycling facility or a permanent pit that is a natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to accumulate produced water and has a design storage capacity equal to or greater than 50,000 barrels.

~~JJ~~RR. "Qualified Professional Engineer" means an individual who is licensed by a state as a professional engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge, and experience to make the specific technical certifications required under this Part.

~~KK~~SS. "Reciprocating compressor" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of a piston rod.

~~LL~~TT. "Reconstruction" means a modification that results in the replacement of the components or addition of integrally related equipment to an existing source, to such an extent that the fixed capital cost of the new components or equipment exceeds fifty percent of the fixed capital cost that would be required to construct a comparable entirely new facility.

~~MM~~UU.“Recycling facility” means a stationary or portable facility used exclusively for the treatment, re-use, or recycling of produced water and does not include oilfield equipment such as separators, heater treaters, and scrubbers in which produced water may be used.

~~NN~~VV. “Responsible official” means one of the following:

(1) for a corporation: president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of the corporation if the representative is responsible for the overall operation of the source.

(2) for a partnership or sole proprietorship: a general partner or the proprietor, respectively.

~~OO~~WW. “Small business facility” means, for the purposes of this Part, a source that is independently owned or operated by a company that is a not a subsidiary or a division of another business, that employs no more than 10 employees at any time during the calendar year, and that has a gross annual revenue of less than $250,000. Employees include part-time, temporary, or limited service workers.

~~PP~~XX. “Startup” means the setting into operation of air pollution control equipment or process equipment.

~~QQ~~YY. “Stationary Source” or **"source"** means any building, structure, equipment, facility, installation (including temporary installations), operation, process, or portable stationary source that emits or may emit any air contaminant. Portable stationary source means a source that can be relocated to another operating site with limited dismantling and reassembly.

~~RR~~ZZ. “Storage vessel” means a single tank or other vessel that is designed to contain an accumulation of hydrocarbon liquid or produced water and is constructed primarily of non-earthen material including wood, concrete, steel, fiberglass, or plastic, which provide structural support, or a process vessel such as a surge control vessel, bottom receiver, or knockout vessel. A well completion vessel that receives recovered liquid from a well after commencement of operation for a period that exceeds 60 days is considered a storage vessel. A storage vessel does not include a vessel that is skid-mounted or permanently attached to a mobile source and located at the site for less than 180 consecutive days, such as a truck railcar, or a pressure vessel designed to operate in excess of 204.9 kilopascals without emissions to the atmosphere.

AAA. “Vessel measurement system” means equipment and methods used to determine the quantity of the liquids inside a vessel (including a flowback vessel) without requiring direct access through the vessel thief hatch or other opening.

~~SS~~BBB. “Well workover” means the repair or stimulation of an existing production well for the purpose of restoring, prolonging, or enhancing the production of hydrocarbons.

~~TT~~CCC. “Wellhead site” means the equipment directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. A wellhead site may include equipment used for extraction, collection, routing, storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and product piping.
[20.2.50.7 NMAC - N, XX/XX/2021]

20.2.50.8 SEVERABILITY: If any provision of this Part, or the application of this provision to any person or circumstance is held invalid, the remainder of this Part, or the application of this provision to any person or circumstance other than those as to which it is held invalid, shall not be affected thereby.
[20.2.50.8 NMAC - N, XX/XX/2021]

20.2.50.9 CONSTRUCTION: This Part shall be liberally construed to carry out its purpose.
[20.2.50.9 NMAC - N, XX/XX/2021]

20.2.50.10 SAVINGS CLAUSE: Repeal or supersession of prior versions of this Part shall not affect administrative or judicial action initiated under those prior versions.
[20.2.50.10 NMAC - N, XX/XX/2021]

20.2.50.11 COMPLIANCE WITH OTHER REGULATIONS: Compliance with this Part does not relieve a person from the responsibility to comply with other applicable federal, state, or local laws, rules or regulations, including more stringent controls.
[20.2.50.11 NMAC - N, XX/XX/2021]

20.2.50.12 DOCUMENTS: Documents incorporated and cited in this Part may be viewed at the New

Mexico environment department, air quality bureau.
[20.2.50.12 NMAC - N, XX/XX/2021]
[The Air Quality Bureau is located at 525 Camino de los Marquez, Suite 1, Santa Fe, New Mexico 87505.]

20.2.23.13-20.2.23.110 [**RESERVED**]

20.2.50.111 APPLICABILITY:

A. This Part applies to crude oil and natural gas production and processing equipment and operations that extract, collect, separate, dehydrate, store, process, transport, transmit, or handle hydrocarbon liquid or produced water in the areas specified in 20.2.50.2 NMAC and are located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations, up to the point of the local distribution company custody transfer station.

B. In determining if any source is subject to this Part, including a small business facility as defined in this Part, the owner or operator shall calculate the Potential to Emit (PTE) of such source and shall have the PTE calculation certified by a qualified professional engineer. The calculation shall be kept on file for a minimum of five years and shall be provided to the department upon request.

C. An owner or operator of a small business facility as defined in this Part shall comply with the requirements of this Part as specified in 20.2.50.125 NMAC.

D. Oil refinery and transmission pipelines are not subject to this Part.

[20.2.50.111 NMAC - N, XX/XX/2021]

20.2.50.112 GENERAL PROVISIONS:

A. General requirements:

(1) Sources subject to emissions standards and requirements under this Part shall be operated and maintained consistent with manufacturer specifications, and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available upon request by the department. For sources constructed prior to 1980 for which no manufacturer specifications and maintenance practices are available, the owner or operator shall develop and follow a maintenance schedule sufficient to operate and maintain such units in good working order. The owner or operator shall keep such maintenance schedules on file and make them available to the department upon request.

(2) Sources subject to emission standards or requirements under this Part shall be operated to minimize emissions of air contaminants, including VOC and NO_x.

(3) Within two years of the effective date of this Part, owners and operators of a source requiring an Equipment Monitoring Tag (EMT) shall physically tag each unit with an EMT, the format of which shall be either RFID, QR, or bar code such that, when scanned it provides a unique identifier of the source. This unique identifier shall act as an index to the source's record of the data required by this Part. The EMT shall be maintained by the owner or operator, and data in the EMT shall provide at a minimum, the following information:

(a) unique unit identification number;

(b) location of the source;

(c) type of source (e.g., tank, VRU, dehydrator, pneumatic controller, etc.);

(d) for each source, the VOC (and NO_x, if applicable) PTE in lbs./hr. and tpy;

(e) for a control device, the controlled VOC and NO_x PTE in lbs./hr. and tpy;

(f) make, model, and serial number; and

(g) a link to the manufacturer's maintenance schedule or repair recommendations.

(4) The EMT shall be installed and maintained by the owner or operator of the facility.

(5) The EMT shall be of a format scannable by an owner or operator's authorized representatives and, upon scanning, shall provide unique identifier that shall index the source's record of the data required by this Part.

(6) The owner or operator shall manage the source's record of data in a database that is able to generate a Compliance Database Report (CDR). The CDR is an electronic report generated by the owner or operator's database and submitted to the department upon request. The format of the CDR shall be determined by the department.

(7) The CDR is a report distinct from the owner or operator's database. The department does not require access to the owner or operator's database, only the CDR.

(8) If read by the owner or operator's authorized representative, the EMT shall access the owner or operator's database record for that source.

(9) The owner or operator shall contemporaneously track each compliance event for each source subject to the EMT requirements of this Part, and shall comply with the following:

(a) data gathered during each monitoring or testing event shall be contemporaneously uploaded into the database as soon as practicable, but no later than three business days of each compliance event.

(b) data required by this Part shall be maintained in the database for at least five years.

(10) The department may request that an owner or operator retain a third party at their own expense to verify any data or information collected, reported, or recorded pursuant to this Part, and make recommendations to correct or improve the collection of data or information. The owner or operator shall submit a report of the verification and any recommendations made by the third party to the department by a date specified and implement the recommendations in the manner approved by the department.

B. Monitoring requirements:

(1) Sources subject to emission standards and monitoring (e.g. inspection, testing, parametric monitoring) requirements under this Part shall be inspected monthly to ensure proper maintenance and operation, unless a different schedule is specified in the Section applicable to that source type. If the equipment is shut down at the time of required periodic testing, monitoring, or inspection, the owner or operator shall not be required to restart the unit for the sole purpose of performing the testing, monitoring, or inspection, but shall note the shut down in the records kept for that equipment for that monitoring event.

(2) An owner or operator may submit for the department's review and approval an equally effective, enforceable, and equivalent alternative monitoring strategy. Such requests shall be made on an application form provided by the department. The department shall issue a letter approving or denying the requested alternative monitoring strategy. An owner or operator shall comply with the default monitoring requirements required under the applicable Section and shall not operate under an alternative monitoring strategy until it has been approved by the department.

(3) Each monitoring event (e.g. testing, inspection, parametric monitoring) shall be initiated by an initial scanning of the EMT, the results of which shall then be directly uploaded into the database or temporarily into the handheld or other device. Upon completion of the monitoring event, a final scanning of the EMT shall terminate the monitoring event. At a minimum, the uploaded data shall include:

(a) date and time of the testing, monitoring, or inspection event;

(b) name of the personnel conducting the testing, monitoring, or inspection;

(c) identification number and type of unit;

(d) a description of any maintenance or repair activity conducted; and

(e) results of testing, monitoring, or inspection as required under this Part.

C. Recordkeeping requirements:

(1) Within three business days of a monitoring event, an electronic record shall be made of the monitoring event and shall include the following data:

(a) date and time of the testing, monitoring, or inspection event;

(b) name of the personnel conducting the testing, monitoring, or inspection;

(c) identification number and type of unit;

(d) a description of any maintenance or repair activity conducted; and

(e) results of any testing, monitoring, or inspections required under this Part.

(2) The owner or operator shall keep an electronic record required by this Part for five years. The department may treat loss of data or failure to maintain a record, including failure to transfer a record upon sale or transfer of ownership or operating authority, as a failure to collect the data.

(3) Before the transfer of ownership of equipment subject to this Part, the current owner or operator shall conduct and document a full compliance evaluation of such equipment. The documentation shall include a certification by a responsible official as to whether the equipment is in compliance with the requirements of this Part. The compliance determination shall be conducted no earlier than three months before the transfer of ownership. The owner or operator shall keep the full compliance evaluation and certification by the responsible official for ~~for~~ five years.

D. Reporting requirements: Within 24 hours of a request by the department, the owner or operator shall for each unit subject to the request, provide the requested information either by electronically submitting a CDR to the department's Secure Extranet Portal (SEP), or by other means and formats specified by the department in its request.

[20.2.50.112 NMAC - N, XX/XX/2021]

20.2.50.113 ENGINES AND TURBINES:

A. Applicability: Portable and stationary natural gas-fired spark ignition engines, compression ignition engines, and natural gas-fired combustion turbines located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations, with a rated horsepower greater than the horsepower ratings of Table 1, 2, and 3 of 20.2.50.113 NMAC are subject to the requirements of 20.2.50.113 NMAC.

B. Emission standards:

(1) The owner or operator of a portable or stationary natural gas-fired spark-ignition engine, compression ignition engine, or natural gas-fired combustion turbine shall ensure compliance with the emission standards by the dates specified in Subsection B of 20.2.50.113 NMAC.

(2) The owner or operator of an existing natural gas-fired spark-ignition engine shall complete an inventory of all existing engines by January 1, 2023, and shall prepare a schedule to ensure that each existing engine does not exceed the emission standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC as follows:

(a) by January 1, 2025, the owner or operator shall ensure at least thirty percent of the company's existing engines meet the emission standards.

(b) by January 1, 2027, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing engines meets the emission standards.

(c) by January 1, 2029, the owner or operator shall ensure that the remaining thirty-five percent of the company's existing engines meets the emission standards.

(d) in lieu of meeting the emission standards for an existing natural gas-fired spark ignition engine, an owner or operator may reduce the annual hours of operation of an engine such that the annual NOx and VOC emissions are reduced by at least ninety-five percent per year.

Table 1 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED, RECONSTRUCTED, OR INSTALLED BEFORE THE EFFECTIVE DATE OF 20.2.50 NMAC.

Engine Type	Rated bhp	NO_x	CO	NMNEHC (as propane)
Lean-burn	>1,000	0.50 g/bhp-hr	47 ppmvd @ 15% O_2 or 93% reduction	0.70 g/bhp-hr
Rich-burn	>1,000	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

(3) The owner or operator of a new natural gas-fired spark ignition engine shall ensure the engine does not exceed the emission standards in table 2 of Paragraph (3) of Subsection B of 20.2.50.113 NMAC upon startup.

Table 2 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED, RECONSTRUCTED, OR INSTALLED AFTER THE EFFECTIVE DATE OF 20.2.50 NMAC.

Engine Type	Rated bhp	NO_x	CO	NMNEHC (as propane)
Lean-burn	>500 - <1,000	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Lean-burn	≥1,000	0.30 g/bhp-hr uncontrolled or 0.05 g/bhp-hr with control	0.60 g/bhp-hr	0.70 g/bhp-hr
Rich-burn	>500	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

(4) The owner or operator of a natural gas-fired spark ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(5) The owner or operator of a compression ignition engine shall ensure compliance with the following emission standards:

(a) a new portable or stationary compression ignition engine with a maximum design power output equal to or greater than 500 horsepower that is not subject to the emission standards under Subparagraph (b) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC shall limit NO_x emissions to not more than nine g/bhp-hr upon startup.

(b) a stationary compression ignition engine that is subject to and complying with Subpart IIII of 40 CFR Part 60, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, is not subject to the requirements of Subparagraph (a) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC.

(6) The owner or operator of a portable or stationary compression ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(7) The owner or operator of a stationary natural gas-fired combustion turbine with a maximum design rating equal to or greater than 1,000 bhp shall comply with the applicable emission standards for an existing, new, or reconstructed turbine listed in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC.

Table 3 - EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

<table>
<tr><td colspan="4">For each natural gas-fired combustion turbine constructed or reconstructed and installed before the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards no later than two years from the effective date of this Part:</td></tr>
<tr><td>Turbine Rating (bhp)</td><td>NO_x (ppmvd @15% O_2)</td><td>CO (ppmvd @ 15% O_2)</td><td>NMNEHC (as propane, ppmvd @15% O_2)</td></tr>
<tr><td>≥1,000 and <5,000</td><td>50</td><td>50</td><td>9</td></tr>
<tr><td>≥5,000 and <15,000</td><td>50</td><td>50</td><td>9</td></tr>
<tr><td>≥15,000</td><td>50</td><td>50 or 93% reduction</td><td>5 or 50% reduction</td></tr>
<tr><td colspan="4">For each natural gas-fired combustion turbine constructed or reconstructed and installed on or after the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards upon startup:</td></tr>
<tr><td>Turbine Rating (bhp)</td><td>NO_x (ppmvd @15% O_2)</td><td>CO (ppmvd @ 15% O_2)</td><td>NMNEHC (as propane, ppmvd @15% O_2)</td></tr>
<tr><td>≥1,000 and <5,000</td><td>25</td><td>25</td><td>9</td></tr>
<tr><td>≥5,000 and <15,900</td><td>15</td><td>10</td><td>9</td></tr>
<tr><td>≥15,900</td><td>9.0 Uncontrolled or
2.0 with Control</td><td>10 Uncontrolled or
1.8 with Control</td><td>5</td></tr>
</table>

(8) The owner or operator of a stationary natural gas-fired combustion turbine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(9) The owner or operator of an engine or turbine shall install an EMT on the engine or turbine in accordance with 20.2.50.112 NMAC.

(10) The owner or operator of an emergency use engine that is operated less than 100 hours per year is not subject to the emissions standards in this Part but shall be equipped with a non-resettable hour meter to monitor and record any hours of operation.

C. Monitoring requirements:

(1) Maintenance and repair for a spark-ignition engine, compression-ignition engine, and stationary combustion turbine shall meet the minimum manufacturer recommended maintenance schedule. The following maintenance, adjustment, replacement, or repair events for engines and turbines shall be documented as they occur:

(a) routine maintenance that takes a unit out of service for more than two hours during any 24-hour period; and

(b) unscheduled repairs that require a unit to be taken out of service for more than two hours during any 24-hour period.

(2) Catalytic converters (oxidative, selective and non-selective) and AFR controllers shall be maintained according to manufacturer or supplier recommended maintenance schedules, including replacement of oxygen sensors as necessary for oxygen-based controllers. During periods of catalytic converter or AFR controller maintenance, the owner or operator shall shut down the engine or turbine until the catalytic converter or AFR controller can be replaced with a functionally equivalent spare to allow the engine or turbine to return to operation.

(3) For equipment operated for 500 hours per year or more, compliance with the emission standards in Subsection B of 20.2.50.113 NMAC shall be demonstrated by performing an initial emissions test, followed by annual tests, for NO_x, CO, and non-methane non-ethane hydrocarbons (NMNEHC) using a portable analyzer or U.S. EPA reference method. For units with g/hp-hr emission standards, the engine load shall be calculated using the following equations:

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (scf/hr) x Measured fuel heating value (LHV btu/scf)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (gal/hr) x Measured fuel heating value (LHV btu/gal)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

Where: LVH = lower heating value, btu/scf, or btu/gal, as appropriate; and
BSFC = brake specific fuel consumption

(a) emissions testing events shall be conducted at ninety percent or greater of the unit's capacity. If the ninety percent capacity cannot be achieved, the monitoring and testing shall be conducted at the maximum achievable capacity or load under prevailing operating conditions. The load and the parameters used to calculate it shall be recorded to document operating conditions at the time of testing and shall be included with the test report.

(b) emissions testing utilizing a portable analyzer shall be conducted in accordance with the requirements of the current version of ASTM D 6522. If a portable analyzer has met a previously approved department criterion, the analyzer may be operated in accordance with that criterion until it is replaced.

(c) the default time period for a test run shall be at least 20 minutes.

(d) an emissions test shall consist of three separate runs, with the arithmetic mean of the results from the three runs used to determine compliance with the applicable emission standard.

(e) during emissions tests, pollutant and diluent concentration shall be monitored and recorded. Fuel flow rate shall be monitored and recorded if stack gas flow rate is determined utilizing U.S. EPA reference method 19. This information shall be included with the periodic test report.

(f) stack gas flow rate shall be calculated in accordance with U.S. EPA reference method 19 utilizing fuel flow rate (scf) determined by a dedicated fuel flow meter and fuel heating value (Btu/scf). The owner or operator shall provide a contemporaneous fuel gas analysis (preferably on the day of the test, but no earlier than three months before the test date) and a recent fuel flow meter calibration certificate (within the most recent quarter) with the final test report. Alternatively, stack gas flow rate may be determined by using U.S. EPA reference methods 1 through 4 or through the use of manufacturer provided fuel consumption rates.

(g) upon request by the department, an owner or operator shall submit a notification and protocol for an initial or annual emissions test.

(h) emissions testing shall be conducted at least once per calendar year. Emission testing required by Subparts GG, IIII, JJJJ, or KKKK of 40 CFR 60, or Subpart ZZZZ of 40 CFR 63, may be used to satisfy the emissions testing requirements if it meets the requirements of 20.2.50.113 NMAC and is completed at least once per calendar year.

(4) The owner or operator of equipment operated less than 500 hours per year shall monitor the hours of operation using a non-resettable hour meter and shall test the unit at least once per 8760 hours of operation in accordance with the emissions testing requirements in Paragraph (3) of Subsection C of 20.2.50.113 NMAC.

(5) An owner or operator of an emergency use engine operated for less than 100 hours per year shall monitor the hours of operation by a non-resettable hour meter.

(6) An owner or operator limiting the annual operating hours of an engine to meet the requirements of Paragraph (2) of Subsection B of 20.2.50.113 NMAC shall monitor the hours of operation by a non-resettable hour meter.

(7) Prior to monitoring, testing, inspection, or maintenance of an engine or turbine, the owner or operator shall scan the EMT, and the monitoring data entry shall be made in accordance with the requirements of 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain a record in accordance with 20.2.50.112 NMAC for the engine or turbine. The record shall include:

(a) the make, model, serial number, and EMT for the engine or turbine;

(b) a copy of the engine, turbine, or control device manufacturer recommended maintenance and repair schedule;

(c) all inspection, maintenance, or repair activity on the engine, turbine, and control device, including:

(i) the date and time of an inspection, maintenance or repair;

(ii) the date a subsequent analysis was performed (if applicable);

(iii) the name of the personnel conducting the inspection, maintenance or repair;

(iv) a description of the physical condition of the equipment as found during the inspection;

(v) a description of maintenance or repair activity conducted; and

(vi) the results of the inspection and any required corrective actions.

(2) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain records of initial and annual emissions testing for the engine or turbine. The records shall include:

(a) the make, model, serial number, and EMT for the tested engine or turbine;

(b) the date and time of sampling or measurements;

(c) the date analyses were performed;

(d) the name of the personnel and the qualified entity that performed the analyses;

(e) the analytical or test methods used;

(f) the results of analyses or tests;

(g) for equipment operated less than 500 hours per year, the total annual hours of operation as recorded by the non-resettable hour meter; and

(h) operating conditions at the time of sampling or measurement.

(3) The owner or operator of an emergency use engine operated less than 100 hours per year shall record the total annual hours of operation as recorded by the non-resettable hour meter.

(4) The owner or operator limiting the annual operating hours of an engine to meet the requirements of Paragraph (2) of Subsection B of 20.2.50.113 NMAC shall record the hours of operation by a non-resettable hour meter. The owner or operator shall calculate and record the annual NOx and VOC emission calculation, based on the engine's actual hours of operation, to demonstrate the ninety-five percent emission reduction requirement is met.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.113 NM–C - N, XX/XX/2021]

20.2.50.114 COMPRESSOR SEALS:

A. Applicability:

(1) Centrifugal compressors using wet seals and located at tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.114 NMAC. Centrifugal compressors located at wellhead sites are not subject to the requirements of 20.2.50.114 NMAC.

(2) Reciprocating compressors located at tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.114 NMAC. Reciprocating compressors located at wellhead sites are not subject to the requirements of 20.2.50.114 NMAC.

B. Emission standards:

(1) The owner or operator of an existing centrifugal compressor shall control VOC emissions from a centrifugal compressor wet seal fluid degassing system by at least ninety-five percent within two years of the effective date of this Part. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

(2) The owner or operator of an existing reciprocating compressor shall, either:

(a) replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation or every 36 months, whichever is reached later. The owner or operator shall begin counting the hours of compressor operation toward the first replacement of the rod packing upon the effective date of this Part; or

(b) beginning no later than two years from the effective date of this Part, collect emissions from the rod packing under negative pressure and route them via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

(3) The owner or operator of a new centrifugal compressor shall control VOC emissions from the centrifugal compressor wet seal fluid degassing system by at least ninety-eight percent upon startup. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) The owner or operator of a new reciprocating compressor shall, upon startup, either:

(a) replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation, or every 36 months, whichever is reached later; or

(b) collect emissions from the rod packing under negative pressure and route them via a closed vent system to a control device, a recovery system, fuel cell or a process stream.

(5) The owner or operator of a centrifugal or reciprocating compressor shall install an EMT on the compressor in accordance with 20.2.50.112 NMAC.

(6) The owner or operator complying with the emission standards in Subsection B of 20.2.50.114 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator of a centrifugal compressor complying with Paragraph (1) or (3) of Subsection B of 20.2.50.114 NMAC shall maintain a closed vent system encompassing the wet seal fluid degassing system that complies with the monitoring requirements in 20.2.50.115 NMAC.

(2) The owner or operator of a reciprocating compressor complying with Subparagraph (a) of Paragraph (2) or Subparagraph (a) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall continuously monitor the hours of operation with a non-resettable hour meter and track the number of hours since initial startup or since the previous reciprocating compressor rod packing replacement.

(3) The owner or operator of a reciprocating compressor complying with Subparagraph (b) of Paragraph (2) or Subparagraph (b) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall monitor the rod packing emissions collection system semiannually to ensure that it operates under negative pressure and routes emissions through a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a closed vent system or control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(5) The owner or operator of a centrifugal or reciprocating compressor shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a centrifugal compressor using a wet seal fluid degassing system shall maintain a record of the following:

(a) the location of the centrifugal compressor;

(b) the date of construction, reconstruction, or modification of the centrifugal compressor;

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including the time and date of the monitoring, the personnel conducting the monitoring, a description of any problem observed during the monitoring, and a description of any corrective action taken; and

(d) the type, make, model, and identification number of a control device used to comply with the control requirements in Subsection B of 20.2.50.114 NMAC.

(2) The owner or operator of a reciprocating compressor shall maintain a record of the following:

(a) the location of the reciprocating compressor;

(b) the date of construction, reconstruction, or modification of the reciprocating compressor; and

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including:

(i) the number of hours of operation since initial startup or the last rod packing replacement;

(ii) the records of pressure in the rod packing emissions collection system; and

(iii) the time and date of the inspection, the personnel conducting the inspection, a notation of which checks required in Subsection C of 20.2.50.114 NMAC were completed, a description of problems observed during the inspection, and a description and date of corrective actions taken.

(3) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a control device or closed vent system shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(4) The owner or operator of a centrifugal or reciprocating compressor shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. **Reporting requirements:** The owner or operator of a centrifugal or reciprocating compressor shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.114 NM–C - N, XX/XX/2021]

20.2.50.115 CONTROL DEVICES:

A. **Applicability:** These requirements apply to control devices as defined in 20.2.50.7 NMAC and used to comply with the emission standards and emission reduction requirements in this Part.

B. **General requirements:**

(1) Control devices used to demonstrate compliance with this Part shall be installed, operated, and maintained consistent with manufacturer specifications, and good engineering and maintenance practices.

(2) Control devices shall be adequately designed and sized to achieve the control efficiency rates required by this Part and to handle fluctuations in emissions of VOC or NO_x.

(3) The owner or operator of a control device used to comply with the emission standards in this Part shall install an EMT on the control device in accordance with 20.2.50.112 NMAC.

(4) The owner or operator shall inspect control devices used to comply with this Part at least monthly to ensure proper maintenance and operation. Prior to an inspection or monitoring event, the owner or operator shall scan the EMT and the required monitoring data shall be electronically captured in accordance with this Part.

(5) The owner or operator shall ensure that a control device used to comply with emission standards in this Part operates as a closed vent system that captures and routes VOC emissions to the control device, and that unburnt gas is not directly vented to the atmosphere.

(6) The owner or operator of a closed vent system for a centrifugal compressor wet seal fluid degassing system, reciprocating compressor, pneumatic controller or pump, ~~or~~ storage vessel, or flowback vessel using a control device or routing emissions to a process shall:

(a) ensure the control device or process is of sufficient design and capacity to accommodate all emissions from the affected sources;

(b) conduct an assessment to confirm that the closed vent system is of sufficient design and capacity to ensure that all emissions from the affected equipment are routed to the control device or process; and

(c) have the closed vent system certified by a qualified professional engineer or an in-house engineer with expertise regarding the design and operation of the closed vent system in accordance with Paragraphs (c)(i) and (ii) of this Section.

(i) The assessment of the closed vent system shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in Paragraph (c)(ii) of this Section.

(ii) the owner or operator shall provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: “I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted, and this report was prepared pursuant to the requirements of this Part. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete.”

(7) The owner or operator shall keep manufacturer specifications for all control devices on file. The information shall include:

(a) manufacturer name, make, and model;

(b) maximum heating value for an open flare, ECD, or TO;

(c) maximum rated capacity for an open flare, ECD/TO, or VRU;
(d) gas flow range for an open flare, ECD, or TO; and
(e) designed destruction or vapor recovery efficiency.

C. Requirements for open flares:

(1) Emission standards:

(a) the flare shall combust the gas sent to the flare and combustion shall be maintained for the duration of time that gas is sent to the flare. The owner or operator shall not send gas to the flare in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip each new and existing flare (except those flares required to meet the requirements of Paragraph (C) of this Subsection) with a continuous pilot flame, an operational auto-igniter, or require manual ignition, and shall comply with the following:

(i) a flare with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure the flare is operated with a flame present at all times when gas is being sent to the flare.

(ii) the owner or operator of a flare with manual ignition shall inspect and ensure a flame is present upon initiating a flaring event.

(iii) a new flare controlling a continuous gas stream shall be equipped with a continuous pilot flame upon startup.

(iv) an existing flare controlling a continuous gas stream constructed before the effective date of this Part shall be equipped with a continuous pilot no later than one year after the effective date of this Part.

(c) an existing flare located at a site with an annual average daily production of equal to or less than 10 barrels of oil per day or an average daily production of 60,000 standard cubic feet of natural gas shall be equipped with an auto-ignitor, continuous pilot, or technology (e.g. alarm) that alerts the owner or operator of a flare malfunction, if replaced or reconstructed after the effective date of this Part.

(d) the owner or operator shall operate a flare with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The flare shall be designed so that an observer can, by means of visual observation from the outside of the flare or by other means such as a continuous monitoring device, determine whether it is operating properly.

(e) the owner or operator shall repair the flare within three business days of any alarm activation.

(2) Monitoring requirements:

(a) the owner or operator of a flare with a continuous pilot or auto igniter shall continuously monitor the presence of a pilot flame, or presence of flame during flaring if using an auto igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department;

(b) the owner or operator of a manually ignited flare shall monitor the presence of a flame using continuous visual observation during a flaring event;

(c) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the flare pilot or auto igniter flame is present to certify compliance with visible emission requirements. The observation period shall be a minimum of 15 consecutive minutes;

(d) prior to an inspection or monitoring event, the EMT on the flare shall be scanned and the required monitoring data shall be electronically captured during the event in accordance with the monitoring requirements of 20.2.50.112 NMAC; and

(e) the owner or operator shall monitor the technology that alerts the owner or operator of a flare malfunction and any instances of technology or alarm activation.

(3) Recordkeeping requirements: The owner or operator of an open flare shall keep a record of the following:

(a) any instance of alarm activation, including the date and cause of alarm activation, action taken to bring the flare into a normal operating condition, the name of the personnel conducting the inspection, and any maintenance activity performed;

(b) the results of the U.S. EPA method 22 observations;

(c) the monitoring of the presence of a flame on a manual flare during a flaring event as required under Subparagraph (b) of Paragraph (2) of Subsection C of 20.2.50.115 NMAC;

(d) the results of the gas analysis for the gas being flared, including VOC content and heating value; and

(e) any instance of technology or alarm activation of a malfunctioning flare, including the date and cause of the activation, the action taken to bring the flare into normal operating condition, date of repair, name of the personnel conducting the inspection, and any maintenance activities performed.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

D. Requirements for enclosed combustion devices (ECD) and thermal oxidizers (TO):

(1) Emission standards:

(a) the ECD/TO shall combust the gas sent to the ECD/TO. The owner or operator shall not send gas to the ECD/TO in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip an ECD/TO with a continuous pilot flame or an auto-igniter. Existing ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter no later than one year after the effective date. New ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter upon startup.

(c) ECD/TO with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure that the ECD/TO is operated with a flame present at all times when gas is sent to the ECD/TO. Combustion shall be maintained for the duration of time that gas is sent to the ECD/TO.

(d) the owner or operator shall operate an ECD/TO with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The ECD/TO shall be designed so that an observer can, by means of visual observation from the outside of the ECD/TO or by other means such as a continuous monitoring device, determine whether it is operating properly.

(2) Monitoring requirements:

(a) the owner or operator of an ECD/TO with a continuous pilot or an auto igniter shall continuously monitor the presence of a pilot flame, or of a flame during combustion if using an auto-igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department.

(b) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the ECD/TO pilot flame or auto igniter flame is present to certify compliance with the visible emission requirements. The period of observation shall be a minimum of 15 consecutive minutes.

(c) prior to an inspection or monitoring event, the EMT on the unit shall be scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 20.2.50.112 NMAC.

(3) Recordkeeping requirements: The owner or operator of an ECD/TO shall keep records of the following:

(a) any instance of an alarm activation, including the date and cause of the activation, any action taken to bring the ECD/TO into normal operating condition, the name of the personnel conducting the inspection, and any maintenance activities performed;

(b) the result of the U.S. EPA method 22 observation; and

(c) the results of gas analysis for the gas being combusted, including VOC content and heating value.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

E. Requirements for vapor recover units (VRU):

(1) Emission standards:

(a) the owner or operator shall operate the VRU as a closed vent system that captures and routes all VOC emissions directly back to the process or to a sales pipeline and does not vent to the atmosphere.

(b) the owner or operator shall control VOC emissions during startup, shutdown, maintenance, or other VRU downtime with a backup control device (e.g. flare, ECD, TO) or redundant VRU.

(2) Monitoring Requirements:

(a) the owner or operator shall comply with the standards for equipment leaks in 20.2.50.116 NMAC, or, alternatively, shall implement a program that meets the requirements of Subpart OOOOa of 40 CFR 60.

(b) prior to a VRU inspection or monitoring event, the EMT on the unit shall be scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 20.2.50.112 NMAC.

(3) Recordkeeping requirements: For a VRU inspection or monitoring event, the owner or operator shall record the result of the event in accordance with 20.2.50.112 NMAC, including the name of the personnel conducting the inspection, and any maintenance or repair activities required. The owner or operator shall record the type of redundant control device used during VRU downtime.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

F. Recordkeeping requirements: The owner or operator of a control device shall maintain a record of the following:

(1) the certification of the closed vent system as required by this Part; and

(2) the information required in Paragraph (7) of Subsection B of 20.2.50.115 NMAC.

G. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

H. Requirements for flowback vessels and preproduction operations:

(1) Emissions standards:

(a) the owner or operator of a well that begins flowback on or after the effective date of this Part must collect and control emissions from each flowback vessel on and after the date flowback is routed to the flowback vessel by routing emissions to an operating control device that achieves a hydrocarbon control efficiency of at least 95 percent. If a TO or ECD is used, it must have a design destruction efficiency of at least 98 percent for hydrocarbons.

(i) the owner or operator shall use enclosed, vapor-tight flowback vessels with an appropriate pressure relief system to be used only as necessary to ensure safety.

(ii) flowback vessels must be inspected, tested, and refurbished where necessary to ensure the flowback vessel is vapor-tight prior to receiving flowback.

(iii) the owner or operator shall use a vessel measurement system to determine the quantity of liquids in the flowback vessel(s).

(A) Thief hatches or other access points to the flowback vessel must remain closed and latched during activities to determine the quantity of liquids in the flowback vessel(s).

(B) Opening the thief hatch or other access point if required to inspect, test, or calibrate the vessel measurement system or to add biocides or chemicals is not a violation of 20.2.50.115.H(1)(a)(i) NMAC.

(2) Monitoring

(a) Owners and or operators of a well with flowback that begins on or after the effective date of 20.2.50 NMAC, must conduct daily visual inspections of the flowback vessel and any associated equipment, including

(i) visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly seated.

(ii) visual inspection or monitoring of the control device to ensure that it is operating.

(iii) visual inspection of the control device to ensure that the valves for the piping from the flowback vessel to the control device are open.

(3) Recordkeeping

(a) The owner or operator of each flowback vessel subject to Paragraph (1) of Subsection H of Section 20.2.50.115 NMAC must maintain records for a period of five (5) years and make them available to the NMED upon request, including

(i) the API number of the well and the associated facility location, including latitude and longitude coordinates.

(ii) the date and time of the onset of flowback.

(iii) the date and time the flowback vessels were permanently disconnected, if applicable.

(iv) the date and duration of any period where the control device is not operating.

(v) records of the inspections required in Paragraph (2) of Subsection H of Section 20.2.50.115 NMAC, including the time and date of each inspection, a description of any problems observed,

a description and date of any corrective action(s) taken, and the name of the employee or third party performing corrective action(s).
[20.2.50.115 NM–C - N, XX/XX/2021]

20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS:

A. Applicability: Wellhead sites, tank batteries, gathering and boosting sites, gas processing plants, transmission compressor stations, and associated piping and components are subject to the requirements of 20.2.50.116 NMAC.

B. Emission standards: The owner or operator of oil and gas production and processing equipment located at wellhead sites, tank batteries, gathering and boosting sites, gas processing plants, or transmission compressor stations shall demonstrate compliance with this Part by performing the monitoring, recordkeeping, and reporting requirements specified in 20.2.50.116 NMAC.

C. Default Monitoring requirements: Owners and operators shall comply with the following monitoring requirements and the monitoring requirements in 20.2.50.112 NMAC:

(1) The owner or operator of a facility with an annual average daily production of greater than 10 barrels of oil per day or an average daily production of greater than 60,000 standard cubic feet per day of natural gas shall, at least weekly, conduct audio, visual, and olfactory (AVO) inspections of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components as follows:

(a) conduct a visual inspection for: cracks, holes, or gaps in piping or covers; loose connections; liquid leaks; broken or missing caps; broken, cracked or otherwise damaged seals or gaskets; broken or missing hatches; or broken or open access covers or other closure or bypass devices;

(b) conduct an audio inspection for pressure leaks and liquid leaks;

(c) conduct an olfactory inspection for unusual or strong odors;

(d) any positive detection during the AVO inspection shall be considered a leak; and

(e) a leak discovered by an AVO inspection shall be tagged with a visible tag and reported to management or their designee within three calendar days.

(2) The owner or operator of a facility with an annual average daily production of equal to or less than 10 barrels of oil per day or an average daily production of equal to or less than 60,000 standard cubic feet per day of natural gas shall, at least monthly, conduct an audio, visual, and olfactory (AVO) inspection of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify a defect and leaking component as specified in Subparagraphs (a) through (e) of Paragraph (1) of Subsection (C) of 20.2.50.116 NMAC.

(3) The owner or operator of the following facilities shall conduct an inspection using U.S. EPA method 21 or optical gas imaging (OGI) of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify leaking components at a frequency determined according to the following schedules:

(a) for wellhead sites or tank battery facilities:

(i) annually at facilities with a PTE less than two tpy VOC;

(ii) semi-annually at facilities with a PTE equal to or greater than two tpy and less than five tpy VOC; and

(iii) quarterly at facilities with a PTE equal to or greater than five tpy VOC.

(b) for gathering and boosting sites, gas processing plants, and transmission compressor stations:

(i) quarterly at facilities with a PTE less than 25 tpy VOC; and

(ii) monthly at facilities with a PTE equal to or greater than 25 tpy VOC.

(c) for wellhead sites within 1,000 feet of an occupied area:

(i) quarterly at facilities with a PTE less than 5 tpy VOC; and

(ii) monthly at facilities with a PTE equal to or greater than 5 tpy VOC.

(4) Inspections using U.S. EPA method 21 shall meet the following requirements:

(a) the instrument shall be calibrated before each day of its use by the procedures specified in U.S. EPA method 21;

(b) the instrument shall be calibrated with zero air (less than 10 ppm of hydrocarbon in air), and a mixture of methane or n-hexane and air at a concentration near, but nor more than, 10,000 ppm methane or n-hexane; and

(c) a leak is detected if the instrument records a measurement of 500 ppm or greater of hydrocarbon and the measurement is not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

(5) Inspections using OGI shall meet the following requirements:

(a) the instrument shall comply with the specifications, daily instrument checks, and leak survey requirements set forth in Subparagraphs (1) through (3) of Paragraph (i) of 40 CFR 60.18;

(b) a leak is detected if the emission images recorded by the OGI instrument are not associated with normal equipment operation, such as pneumatic device actuation or crank case ventilation.

(6) Components that are difficult, unsafe, or inaccessible to monitor, as determined by the following conditions, are not required to be inspected until it becomes feasible to do so:

(a) difficult to monitor components are those that require elevating the monitoring personnel more than two meters above a supported surface, or that cannot be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to seven and six tenths meters (25 feet) above the ground;

(b) unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring; and

(c) inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

D. Alternative equipment leak monitoring plans: As an equivalent means of compliance with Subsection C of 20.2.50.116 NMAC, an owner or operator may comply with the equipment leak requirements through an alternative monitoring plan as follows:

(1) An owner or operator may comply with an individual alternative monitoring plan, subject to the following requirements:

(a) the proposed alternative monitoring plan shall be submitted to and approved by the department prior to conducting monitoring under that plan.

(b) the department may terminate an approved alternative monitoring plan if the department finds that the owner or operator failed to comply with a provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under Subsection C of 20.2.50.116 NMAC within 15 days.

(2) An owner or operator may comply with a pre-approved monitoring plan maintained by the department, subject to the following requirements:

(a) the owner or operator shall notify the department of the intent to conduct monitoring under a pre-approved monitoring plan, and identify which pre-approved plan will be used, at least 15 days prior to conducting monitoring under that plan.

(b) the department may terminate the use of a pre-approved monitoring plan by the owner or operator if the department finds that the owner or operator failed to comply with the provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under of Subsection C of 20.2.50.116.C NMAC within 15 days.

E. Repair requirements: For a leak detected pursuant to monitoring conducted under 20.2.50.116 NMAC:

(1) the owner or operator shall place a visible tag on the leaking component until the component has been repaired;

(2) leaks shall be repaired within 15 days of discovery, except for leaks detected using OGI, which shall be repaired within seven days of discovery;

(3) the equipment must be re-monitored no later than 15 days after discovery of the leak to demonstrate that it has been repaired; and

(4) if the leak cannot be repaired within 15 days of discovery, or within seven days for a leak detected using OGI, without a process unit shutdown, the leak may be designated "Repair delayed," and must be repaired before the end of the next process unit shutdown.

F. Recordkeeping requirements:

(1) The owner or operator shall keep a record of the following for all AVO, RM21, OGI, or alternative equipment leak monitoring inspection conducted as required under 20.2.50.116 NMAC, and shall provide the record to the department upon request:

(a) facility location;
(b) date of inspection;
(c) monitoring method (e.g. AVO, RM 21, OGI, alternative method approved by the department);
(d) name of the personnel performing the inspection;
(e) a description of any leak requiring repair or a note that no leak was found; and
(f) whether a visible flag was placed on the leak or not;

(2) The owner or operator shall keep the following record for any leak that is detected:
(a) the date the leak is detected;
(b) the date of attempt to repair;
(c) for a leak with a designation of "repair delayed" the following shall be recorded:
(i) reason for delay if a leak is not repaired within the required number of days after discovery;
(ii) signature of the authorized representative who determined that the repair could not be implemented without a process unit shutdown;
(d) date of successful leak repair;
(e) date the leak was monitored after repair and the results of the monitoring; and
(f) a description of the component that is designated as difficult, unsafe, or inaccessible to monitor, an explanation stating why the component was so designated, and the schedule for repairing and monitoring the component.

(3) For a leak detected using OGI, the owner or operator shall keep records of the specifications, the daily instrument check, and the leak survey requirements specified at 40 CFR 60.18(i)(1)-(3).

(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

G. Reporting requirements:

(1) The owner or operator shall certify the use of an alternative equipment leak monitoring plan under Subsection D of 20.2.50.116 NMAC to the department annually, if used.

(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.116 NMAC - N, XX/XX/2021]

20.2.50.117 NATURAL GAS WELL LIQUID UNLOADING:

A. Applicability: Liquid unloading operations including down-hole well maintenance events at natural gas wells are subject to the requirements of 20.2.50.117 NMAC.

B. Emission standards:

(1) The owner or operator of a natural gas well shall use best management practices during the life of the well to avoid the need for liquid unloading.

(2) The owner or operator of a natural gas well shall use the following best management practices during liquid unloading to minimize emissions, consistent with well site conditions and good engineering practices:
(a) reduce wellhead pressure before blowdown;
(b) monitor manual liquid unloading in close proximity to the well or via remote telemetry; and
(c) close well head vents to the atmosphere and return the well to normal production operation as soon as practicable.

(3) The owner or operator of a natural gas well shall use one of the following methods to reduce emissions during an unloading event:
(a) installation and use of a plunger lift;
(b) installation and use of an artificial lift engine; or
(c) installation and use of a control device.

(4) The owner or operator of a natural gas well shall install an EMT on the natural gas well in accordance with 20.2.50.112 NMAC.

C. Monitoring requirements:

(1) The owner or operator shall monitor the following parameters during liquid unloading:
(a) wellhead pressure;
(b) flow rate of the vented natural gas (to the extent feasible); and

(c) duration of venting to the storage vessel or atmosphere.

(2) The owner or operator shall calculate the volume and mass of VOC vented during a liquid unloading event.

(3) A liquid unloading event shall include the scanning of the EMT and monitoring data entry in accordance with the requirements of 20.2.50.112 NMAC.

(4) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall keep the following records for liquid unloading:

(a) identification number and location of the well;

(b) date the liquid unloading was performed;

(c) wellhead pressure;

(d) flow rate of the vented natural gas (to the extent feasible. If not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation);

(e) duration of venting to the storage vessel or atmosphere;

(f) a description of the management practice used to minimize release of VOC emissions before and during the liquid unloading;

(g) the type of control device used to control VOC emissions during the liquid unloading; and

(h) a calculation of the VOC emissions vented during the liquid unloading based on the duration, volume, and mass of VOC.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.117 NMAC - N, XX/XX/2021]

20.2.50.118 GLYCOL DEHYDRATORS:

A. Applicability: Glycol dehydrators with a PTE equal to or greater than two tpy of VOC and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.118 NMAC.

B. Emission standards:

(1) Existing glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank no later than two years after the effective date. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.

(2) New glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank upon startup. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.

(3) The owner or operator of a glycol dehydrator shall comply with the following requirements:

(a) still vent and flash tank emissions shall be routed at all times to the reboiler firebox, condenser, combustion control device, fuel cell, to a process point that either recycles or recompresses the emissions or uses the emissions as fuel, or to a VRU that reinjects the VOC emissions back into the process stream or natural gas gathering pipeline;

(b) if a VRU is used, it shall consist of a closed loop system of seals, ducts and a compressor that reinjects the natural gas into the process or the natural gas pipeline. The VRU shall be operational at least ninety-five percent of the time the facility is in operation, resulting in a minimum combined capture and control efficiency of ninety-five percent. The VRU shall be installed, operated, and maintained according to the manufacturer’s specifications;

(c) still vent and flash tank emissions shall not be vented to the atmosphere; and

(d) the owner or operator of a glycol dehydrator shall install an EMT on the glycol dehydrator in accordance with 20.2.50.112 NMAC.

(4) an owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through use of a control device shall comply with the requirements in 20.2.50.115 NMAC.

(5) The requirements of Subsection B of 20.2.50.118 NMAC cease to apply when the uncontrolled actual annual VOC emissions from a new or existing glycol dehydrator are less than two tpy VOC.

C. Monitoring requirements:

(1) The owner or operator of a glycol dehydrator shall conduct an annual extended gas analysis on the dehydrator inlet gas and calculate the uncontrolled and controlled VOC emissions in tpy.

(2) The owner or operator of a glycol dehydrator shall inspect the glycol dehydrator, including the reboiler and regenerator, and the control device or process the emissions are being routed, semi-annually to ensure it is operating as initially designed and in accordance with the manufacturer recommended operation and maintenance schedule.

(3) An owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through the use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) Owners and operators shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a glycol dehydrator shall maintain a record of the following:

(a) dehydrator location and identification number;

(b) glycol circulation rate, monthly natural gas throughput, and the date of the most recent throughput measurement;

(c) data and methodology used to estimate the PTE of VOC (must be a department approved calculation methodology);

(d) amount of controlled and uncontrolled VOC emissions in tpy;

(e) type, make, model, and identification number of the control device or process the emissions are being routed;

(f) date and results of any equipment inspection, including maintenance or repair activities required to bring the glycol dehydrator into compliance; and

(g) a copy of the glycol dehydrator manufacturer operation and maintenance recommendations.

(2) An owner or operator complying with the requirements in Paragraph (1) or (2) of Subsection B of 20.2.50.118 NMAC through use of a control device as defined in this Part shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(3) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.118 NMAC - N, XX/XX/2021]

20.2.50.119 HEATERS:

A. Applicability: Natural gas-fired heaters with a rated heat input equal to or greater than 10 MMBtu/hour including heater treaters, heated flash separators, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.119 NMAC.

B. Emission standards:

(1) Natural gas-fired heaters shall comply with the emission limits in table 1 of 20.2.50.119 NMAC.

Table 1 - EMISSION STANDARDS FOR NO_x AND CO

Date of Construction:	NO_x (ppmvd @ 3% O_2)	CO (ppmvd @ 3% O_2)
Constructed or reconstructed before the effective date of 20.2.50 NMAC	30	300
Constructed or reconstructed on or after the effective date of 20.2.50 NMAC	30	130

(2) Existing natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC no later than one year after the effective date of this Part.

(3) New natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC upon startup.

(4) The owner or operator of a natural gas-fired heater shall install an EMT on the heater in accordance with 20.2.50.112 NMAC.

C. Monitoring requirements:

(1) The owner or operator shall:

(a) conduct emission testing for NOx and CO within 180 days of the compliance date specified in Paragraph (2) or (3) of Subsection B of 20.2.50.119 NMAC and at least every two years thereafter.

(b) inspect, maintain, and repair the heater in accordance with the manufacturer specifications at least once every two years following the applicable compliance date specified in 20.2.50.119 NMAC. The inspection, maintenance, and repair shall include the following:

(i) inspecting the burner and cleaning or replacing components of the burner as necessary;

(ii) inspecting the flame pattern and adjusting the burner as necessary to optimize the flame pattern consistent with the manufacturer specifications and good engineering practices;

(iii) inspecting the AFR controller and ensuring it is calibrated and functioning properly;

(iv) optimizing total emissions of CO consistent with the NO_x requirement, manufacturer specifications, and good combustion engineering practices; and

(v) measuring the concentrations in the effluent stream of CO in ppmvd and O_2 in volume percent before and after adjustments are made in accordance with Subparagraph (c) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC.

(2) The owner or operator shall comply with the following periodic testing requirements:

(a) conduct three test runs of at least 20-minutes duration within ten percent of one-hundred percent peak, or the highest achievable, load;

(b) determine NO_X and CO emissions and O_2 concentrations in the exhaust with a portable analyzer used and maintained in accordance with the manufacturer specifications and following the procedures specified in the current version of ASTM D6522;

(c) if the measured NO_X or CO emissions concentrations are exceeding the emissions limits of table 1 of 20.2.50.119 NMAC, the owner or operator shall repeat the inspection and tune-up in Subparagraph (b) of Paragraph (1) of Subsection C of 20.2.50.119 NMAC within 30 days of the periodic testing; and

(d) if at any time the heater is operated in excess of the highest achievable load plus ten percent, the owner or operator shall perform the testing specified in Subparagraph (a) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC within 60 days from the anomalous operation.

(3) When conducting periodic testing of a heater, the owner or operator shall follow the procedures in Paragraph (2) of Subsection C of 20.2.50.119 NMAC. An owner or operator may deviate from those procedures by submitting a written request to use an alternative procedure to the department at least 60 days before performing the periodic testing. In the alternative procedure request, the owner or operator must demonstrate the alternative procedure's equivalence to the standard procedure. The owner or operator must receive written approval from the department prior to conducting the periodic testing using an alternative procedure.

(4) Prior to a monitoring, inspection, maintenance, or repair event, the owner or operator shall scan the EMT and the required monitoring data shall be captured in accordance with this Part.

D. Recordkeeping requirements: The owner or operator shall maintain a record of the following:

(1) location of the heater;

(2) summary of the complete test report and the results of periodic testing; and

(3) inspections, testing, maintenance, and repairs, which shall include at a minimum:

(a) the date the inspection, testing, maintenance, or repair was conducted;

(b) name of the personnel conducting the inspection, testing, maintenance, or repair;

(c) concentrations in the effluent stream of CO in ppmv and O_2 in volume percent; and

(d) the results of the inspections and any the corrective action taken.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.119 NMAC - N, XX/XX/2021]

20.2.50.120 HYDROCARBON LIQUID TRANSFERS:

A. Applicability: Hydrocarbon liquid transfers located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.120 NMAC beginning one year from the effective date of this Part.

B. Emission standards:

(1) The owner or operator of a hydrocarbon liquid transfer operation shall use vapor balance, vapor recovery, or a control device to control VOC emissions by at least ninety-eight percent when transferring liquid from a storage vessel to a transfer vessel, or when transferring liquid from a transfer vessel to a storage vessel.

(2) An owner or operator using vapor balance during a liquid transfer operation shall:

(a) transfer the vapor displaced from the vessel being loaded back to the vessel being emptied via a pipe or hose connected before the start of the transfer operation;

(b) ensure that the transfer does not begin until the vapor collection and return system is properly connected;

(c) ensure that connector pipes, hoses, couplers, valves, and pressure relief devices are maintained in a leak-free condition;

(d) check the liquid and vapor line connections for proper connections before commencing the transfer operation; and

(e) operate transfer equipment at a pressure that is less than the pressure relief valve setting of the receiving transport vehicle or storage vessel.

(3) Bottom loading or submerged filling shall be used for the liquid transfer.

(4) Connector pipes and couplers shall be maintained in a leak-free condition.

(5) Connections of hoses and pipes used during liquid transfer operations shall be supported on drip trays that collect any leaks, and the materials collected shall be returned to the process or disposed of in a manner compliant with state law.

(6) Liquid leaks that occur shall be cleaned and disposed of in a manner that prevents emissions to the atmosphere, and the material collected shall be returned to the process or disposed of in a manner compliant with state law.

(7) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator shall visually inspect the transfer equipment during a transfer operation to ensure that liquid transfer lines, hoses, couplings, valves, and pipes are not dripping or leaking. Leaking components shall be repaired to prevent dripping or leaking before the next transfer operation.

(2) The owner or operator of a liquid transfer operation controlled by a control device must follow manufacturer recommended operation and maintenance procedures for the device.

(3) Tanker trucks and tanker rail cars used in liquid transfer service shall be tested annually for vapor tightness in accordance with the following test methods and vapor tightness standards:

(a) method 27 of appendix A of 40 CFR Part 60. Conduct the test using a time period (t) for the pressure and vacuum tests of five minutes. The initial pressure (Pi) for the pressure test shall be 460 mm H_2O (18 inches H_2O), gauge. The initial vacuum (Vi) for the vacuum test shall be 150 mm H_2O (six inches H_2O) gauge. The maximum allowable pressure and vacuum changes (Δp, Δv) are shown in table 1 of 20.2.50.120 NMAC.

Table 1 - ALLOWABLE CARGO TANK TEST PRESSURE OR VACUUM CHANGE

Cargo tank or compartment capacity, liters (gallons)	Allowable vacuum change (Δv) in five minutes, mm H_2O (inches H_2O)	Allowable pressure change (Δp) in five minutes, mm H_2O (inches H_2O)
< 3,785 (< 1,000)	64 (2.5)	102 (4.0)
3,785 < 5,678 (1,000 < 1,500)	51 (2.0)	89 (3.5)
5,678 < 9,464 (1,500 < 2,500)	38 (1.5)	76 (3.0)
> 9,464 (> 2,500)	25 (1.0)	64 (2.5)

(b) pressure test the tanker truck or tanker railcar tank's internal vapor valve as follows:

(i) after completing the tests under Subparagraph (a) of Paragraph (3) of Subsection C of 20.2.50.120 NMAC, use the procedures in method 27 to re-pressurize the tank to 460 mm H_2O (18 inches H_2O) gauge. Close the tank's internal vapor valve, thereby isolating the vapor return line and manifold from the tank.

(ii) relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line. After five minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable five-minute pressure increase is 130 mm H_2O (five inches H_2O).

(4) Owners and operators complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(5) Owners and operators shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain a record of the location of the storage vessel and if using a control device, the type, make, and model of the control device:

(2) The owner or operator shall maintain a record of the inspections and testing required in Subsection C of 20.2.50.120 NMAC and shall include the following:

(a) the time and date of the inspection and testing;

(b) the name of the personnel conducting the inspection and testing;

(c) a description of any problem observed during the inspection and testing; and

(d) the results of the inspection and testing and a description of any repair or corrective action taken.

(3) The owner or operator shall maintain a record for each site of the annual total hydrocarbon liquid transferred and annual total VOC emissions. Each calendar year, the owner or operator shall create a company-wide record summarizing the annual total hydrocarbon liquid transferred and the annual total calculated VOC emissions.

(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.120 NMAC - N, XX/XX/2021]

20.2.50.121 PIG LAUNCHING AND RECEIVING:

A. Applicability: Pipeline pig launching and receiving operations located within or outside of the property boundary of wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.121 NMAC.

B. Emission standards:

(1) Owners and operators of pipeline pig launching and receiving operations with a PTE equal to or greater than one tpy of VOC shall capture and reduce VOC emissions by at least ninety-eight percent, beginning on the effective date of this Part.

(2) The owner or operator conducting the pig launching and receiving operation shall:

(a) employ best management practices to minimize the liquid present in the pig receiver chamber and to prevent emissions from the pig receiver chamber to the atmosphere after receiving the pig in the receiving chamber and before opening the receiving chamber to the atmosphere;

(b) employ a method to prevent emissions, such as installing a liquid ramp or drain, routing a high-pressure chamber to a low-pressure line or vessel, using a ball valve type chamber, or using multiple pig chambers;

(c) recover and dispose of receiver liquid in a manner that prevents emissions to the atmosphere; and

(d) ensure that the material collected is returned to the process or disposed of in a manner compliant with state law.

(3) The emission standards in Paragraphs (1) and (2) of Subsection B of 20.2.50.121 NMAC cease to apply to a pipeline pig launching and receiving operation if the uncontrolled actual annual VOC emissions of the operation are less than one half ton per year of VOC.

(4) An owner or operator complying with Paragraph (2) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator of pig launching and receiving operations shall monitor the type and volume of liquid cleared.

(2) The owner or operator of pig launching and receiving operations shall inspect the equipment for a leak using RM 21 or OGI immediately before the commencement and immediately after the conclusion of the pig launching or receiving operation, and according to the requirements in 20.2.50.116 NMAC.

(3) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of pig launching and receiving operations shall maintain a record of the following:

(a) the pigging operation, including the date and time of the pigging operation and the type and volume of liquid cleared;

(b) the data and methodology used to estimate the actual emissions to the atmosphere and used to estimate the PTE; and

(c) the type of control device and its location, make, and model.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.121 NMAC - N, XX/XX/2021]

20.2.50.122 PNEUMATIC CONTROLLERS AND PUMPS:

A. Applicability: Natural gas-driven pneumatic controllers and pumps located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.122 NMAC.

B. Emission standards:

(1) A new natural gas-driven pneumatic controller or pump shall comply with the requirements of 20.2.50.122 NMAC upon startup.

(2) An existing natural gas-driven pneumatic pump shall comply with the requirements of 20.2.50.122 NMAC within three years of the effective date of this Part.

(3) An existing natural gas-driven pneumatic controller at a site with access to commercial line electrical power, and any existing natural-gas driven pneumatic controller at a transmission compressor station or a natural gas processing plant, shall comply with this Section within six months of the effective date of this Part.

(4) At sites that do not have access to commercial line electrical power, owners and operators shall retrofit their fleet of existing natural gas-driven pneumatic controllers according to the following schedule:~~shall comply with the requirements of 20.2.50.122 NMAC according to the following schedule:~~

TABLE 1. REQUIREMENTS FOR EXISTING NATURAL GAS-DRIVEN PNEUMATIC CONTROLLERS

Total Historic Percentage of Non-Emitting Controllers	**Additional Percentage Required by May 1, 2023**	**Maximum Percentage Required by May 1, 2023**	**Additional Percentage Required by May 1, 2025**	**Maximum Percentage Required by May 1, 2025**
> 75 %	**+15%**	**97%**	**+5%**	**98%**
> 60-75%	**+20%**	**90%**	**+10%**	**98%**
> 40-60 %	**+25%**	**75%**	**+20%**	**95%**
> 20-40 %	**+35%**	**65%**	**+25%**	**90%**
0-20 %	**+40%**	**55%**	**+35%**	**90%**

~~Table 1 – WELLHEAD SITES, TANK BATTERIES, GATHERING AND BOOSTING FACILITIES~~

~~Total Historic Percentage of Non-Emitting Controllers~~	~~Total Required Percentage of Non-Emitting Controllers by January 1, 2024~~	~~Total Required Percentage of Non-Emitting Controllers by January 1, 2027~~	~~Total Required Percentage of Non-Emitting Controllers by January 1, 2030~~

~~> 75 %~~	~~80%~~	~~85%~~	~~90%~~
~~> 60-75 %~~	~~80%~~	~~85%~~	~~90%~~
~~> 40-60 %~~	~~65%~~	~~70%~~	~~80%~~
~~> 20-40 %~~	~~45%~~	~~70%~~	~~80%~~
~~0-20 %~~	~~25%~~	~~65%~~	~~80%~~

~~Table 2 – NATURAL GAS COMPRESSOR STATIONS AND GAS PROCESSING PLANTS~~

~~Total Historic Percentage of Non-Emitting Controllers~~	~~Total Required Percentage of Non-Emitting Controllers by January 1, 2024~~	~~Total Required Percentage of Non-Emitting Controllers by January 1, 2027~~	~~Total Required Percentage of Non-Emitting Controllers by January 1, 2030~~
~~> 75 %~~	~~80%~~	~~95%~~	~~98%~~
~~> 60-75 %~~	~~80%~~	~~95%~~	~~98%~~
~~> 40-60 %~~	~~65%~~	~~95%~~	~~98%~~
~~> 20-40 %~~	~~50%~~	~~95%~~	~~98%~~
~~0-20 %~~	~~35%~~	~~95%~~	~~98%~~

(~~4~~5) Standards for natural gas-driven pneumatic controllers.

(a) new pneumatic controllers shall have an emission rate of zero.

(b) existing pneumatic controllers at sites with access to commercial line electrical power, and any existing pneumatic controller at a transmission compressor station or a natural gas processing plant, shall have an emission rate of zero.

(c) At sites without access to commercial line electrical power, existing pneumatic controllers shall meet the required percentage of non-emitting controllers within the deadlines in table~~s~~ 1 ~~and 2~~ of Paragraph (~~3~~4) of Subsection B of 20.2.50.122 NMAC, and shall comply with the following:

(i) by January 1, 2023, the owner or operator shall determine the total controller count for all controllers at all of the owner or operator's affected facilities that commenced construction before the effective date of this Part. The total controller count must include all emitting pneumatic controllers and all non-emitting pneumatic controllers, except that pneumatic controllers that are permitted under Subparagraph (d) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC,~~necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas~~ shall not be included in the total controller count.

(ii) determine which controllers in the total controller count are non-emitting and sum the total number of non-emitting controllers and designate those as total historic non-emitting controllers.

(iii) determine the total historic non-emitting percent of controllers by dividing the total historic non-emitting controller count by the total controller count and multiplying by 100.

(iv) based on the percent calculated in (iii) above, the owner or operator shall determine which provisions of table~~s~~ 1 ~~and 2~~ of Paragraph (~~3~~4) of Subsection B of 20.2.50.122 NMAC apply and the replacement schedule the owner or operator must meet.

~~**(v)** if an owner or operator meets at least seventy-five percent total non-emitting controllers by January 1, 2025, the owner or operator has satisfied the requirements of tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.~~

~~**(vi)** if after January 1, 2027, an owner or operator's remaining pneumatic controllers are not cost-effective to retrofit, the owner or operator shall submit a cost analysis of retrofitting those remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.~~

(d) a pneumatic controller with a bleed rate greater than ~~six standard cubic feet per hour~~zero is permitted when the owner or operator has demonstrated that a higher bleed rate is required based on functional needs, including response time, safety, and positive actuation. An owner or operator that seeks to maintain operation of an emitting pneumatic controller must prepare and document the justification for the safety or process purposes prior to the installation of a new emitting controller or the retrofit of an existing controller. The justification shall be certified by a qualified professional engineer.

(~~5~~6) Standards for natural gas-driven pneumatic pumps.

(a) pneumatic pumps located at a natural gas processing plants shall have an emission rate of zero.

(b) pneumatic pumps located at a wellhead sites, tank batteries, gathering and boosting sites, or transmission compressor stations with access to commercial line electrical power shall have an emission rate of zero.

(c) owners and operators of pneumatic pumps located at wellhead sites, tank batteries, gathering and boosting sites, or transmission compressor stations without access to commercial line electrical power shall reduce VOC emissions from the pneumatic pumps by ninety-five percent if it is technically feasible to route emissions to a control device, fuel cell, or process. If there is a control device available onsite but it is unable to achieve a ninety-five percent emission reduction, and it is not technically feasible to route the pneumatic pump emissions to a fuel cell or process, the owner or operator shall route the pneumatic pump emissions to the control device.

(6) The owner or operator of a pneumatic controller or pump shall install an EMT on the controller or pump in accordance with 20.2.50.112 NMAC.

C. Monitoring requirements:

(1) Pneumatic controllers or pumps with a natural gas bleed rate equal to zero are not subject to the monitoring requirements in Subsection C of 20.2.5.122 NMAC.

(2) The owner or operator of a pneumatic controller subject to the deadlines set forth in table~~s~~ 1 ~~and 2~~ of Paragraph (~~3~~4) of Subsection B of 20.2.50.122 NMAC shall monitor the compliance status of each subject controller at each facility.

(3) The owner or operator of a pneumatic controller with a bleed rate greater than zero shall, on a monthly basis, scan the controller and conduct an AVO inspection, and shall also inspect the pneumatic controller, perform necessary maintenance (such as cleaning, tuning, and repairing a leaking gasket, tubing fitting and seal; tuning to operate over a broader range of proportional band; eliminating an unnecessary valve positioner), and maintain the pneumatic controller according to manufacturer specifications to ensure that the VOC emissions are minimized.

(4) The owner or operator of a pneumatic controller with a bleed rate greater than zero shall comply with the requirements in Paragraph (3) of Subsection C or Subsection D of 20.2.50.116 NMAC. During instrumental inspections, operators shall use Method 21, OGI, or alternative instruments used under Subsection D of 20.2.50.116 to verify that intermittent controllers are not emitting when not actuating. Any intermittent controller emitting when not actuating shall be repaired consistent with Subsection E of 20.2.50.116 NMAC.

(5) The EMT shall be linked to a database that contains the following:

(a) pneumatic controller identification number;

(b) type of controller (continuous or intermittent);

(c) if continuous, design continuous bleed rate in standard cubic feet per hour;

(d) if intermittent, bleed volume per intermittent bleed in standard cubic feet; and

(e) design annual bleed in standard cubic feet per year.

(~~5~~6) The owner or operator of a pneumatic pump with a bleed rate greater than zero shall, on a monthly basis, scan the pump and conduct an AVO inspection and shall also inspect the pneumatic pump and perform necessary maintenance, and maintain the pneumatic pump according to manufacturer specifications to ensure that the VOC emissions are minimized.

(~~6~~7) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) Pneumatic controllers and pumps with a natural gas bleed rate equal to zero are not subject to the recordkeeping requirements in Subsection D of 20.2.5.122 NMAC.

(2) The owner or operator shall maintain a record of the total controller count for all controllers at all of the owner's or operator's affected facilities that commenced operation before the effective date of this Part. The total controller count must include all emitting and non-emitting pneumatic controllers.

(3) The owner or operator shall maintain a record of the total count of pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting VOC.

(4) The owner or operator of a pneumatic controller subject to the requirements in table~~s~~ 1 ~~and 2~~ of Paragraph (~~3~~4) of shall generate a schedule for meeting the compliance deadlines for each pneumatic controller. The owner or operator shall keep a record of the compliance status of each subject controller.

(5) The owner or operator shall maintain an electronic record for each pneumatic controller with a natural gas bleed rate greater than zero. The record shall include the following:

(a) pneumatic controller identification number;

(b) inspection dates;

(c) name of the personnel conducting the inspection;
(d) AVO inspection result;
(e) AVO level discrepancy in continuous or intermittent bleed rate;
(f) maintenance date and maintenance activity; and
(g) a record of the justification and certification required in Subparagraph (d) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC.

(6) The owner or operator of a natural gas-driven pneumatic controller with a bleed rate greater ~~than six standard cubic feet per hour~~zero shall maintain a record in the EMT database of the pneumatic controller documenting why a bleed rate greater than ~~six scf/hr~~zero is necessary, as required in Subsection B of 20.2.50.122 NMAC.

(7) The owner or operator shall maintain a record in the EMT database for a natural gas-driven pneumatic pump with an emission rate greater than zero and the associated pump number at the facility. The record shall include:

(a) for a natural gas-driven pneumatic pump in operation less than 90 days per calendar year, a record for each day of operation during the calendar year.

(b) a record of any control device designed to achieve at least a ninety-five percent emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve.

(c) records of the engineering assessment and certification by a qualified professional engineer that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

(8) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

(9) The owner or operator of a pneumatic controller with a bleed rate greater than zero shall comply with the requirements in Subsection F of 20.2.50.116 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.122 NMAC - N, XX/XX/2021]

20.2.50.123 STORAGE VESSELS

A. Applicability: Storage vessels with an uncontrolled PTE equal to or greater than two tpy of VOC and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.123 NMAC.

B. Emission standards:

(1) An existing storage vessel with a PTE equal to or greater than two tpy and less than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-five percent no later than three years after the effective date of this Part.

(2) An existing storage vessel with a PTE equal to or greater than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-eight percent no later than one year after the effective date of this Part.

(3) A new storage vessel with a PTE equal to or greater than two tpy and less than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-five percent upon startup.

(4) A new storage vessel with a PTE equal to or greater than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-eight percent upon startup.

(5) The emission standards in Subsection B of 20.2.50.123 NMAC cease to apply to a storage vessel if the uncontrolled actual annual VOC emissions decrease to less than two tpy.

(6) If a control device is not installed by the date specified in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC, an owner or operator may comply with Subsection B of 20.2.50.123 NMAC by shutting in the well supplying the storage vessel by the applicable date, and not resuming production from the well until the control device is installed and operational.

(7) The owner or operator of a new or existing storage vessel with a thief hatch shall install a control device that allows the thief hatch to open sufficiently to relieve overpressure in the vessel and to automatically close once the vessel overpressure is relieved. The thief hatch shall be equipped with a manual lock-open safety device to ensure positive hatch opening during times of human ingress. The lock-open safety device shall only be engaged when an owner or operator are present and during an active ingress activity.

(8) The owner or operator of a new or existing storage vessel shall install an EMT on the storage vessel in accordance with 20.2.50.112 NMAC.

(9) An owner or operator complying with Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the control device operational requirements in 20.2.50.115 NMAC.

C. Storage Vessel Measurement Requirements

(1) The owners and operators of controlled storage tanks at well production facilities, natural gas compressor stations, or natural gas processing plants constructed on or after the effective date of this Part, and at any facilities that are modified on or after the effective date of this Part such that an additional controlled storage vessel is constructed to receive an anticipated increase in throughput of hydrocarbon liquids or produced water, must use a storage vessel measurement system to determine the quantity of liquids in the storage tank(s).

(2) Owners and operators subject to the storage vessel measurement system requirements in this Subsection must keep thief hatches (or other access points to the tank) and pressure relief devices on storage tanks closed and latched during activities to determine the quality and/or quantity of liquids in the storage vessel(s).

(3) Operators may inspect, test, and calibrate the storage vessel measurement system semi-annually, or as directed by the Bureau of Land Management (see 43 CFR Section 3174.6(b)(5)(ii)(B) (November 17, 2016)) or system manufacturer. Opening the thief hatch if required to inspect, test, or calibrate the system is not a violation of Paragraph (1) of this Subsection.

(4) The owner or operator must install signage at or near the storage vessel that indicates which equipment and method(s) are used and the appropriate and necessary operating procedures for that system.

(5) The owner or operator must develop and implement an annual training program for employees and third parties conducting activities subject to this Subsection that includes, at a minimum, operating procedures for each type of system.

(6) Owner or operators must retain records for at least two (2) years and make such records available to the department upon request, including:

(a) Date of construction of the storage vessel or facility;

(b) Description of the storage vessel measurement system used to comply with this Subsection;

(c) Date(s) of storage vessel measurement system inspections, testing, and calibrations pursuant to Paragraph (3) of this Subsection;

(d) Manufacturer specifications regarding storage vessel measurement system inspections, and/or calibrations, if followed pursuant to Paragraph (3) of this Subsection; and

(e) Records of the annual training program, including the date and names of persons trained.

D~~C~~. Monitoring requirements: The owner or operator of a storage vessel shall:

(1) monitor on a monthly basis the total monthly liquid throughput (in barrels) and the upstream separator pressure (in psig). When a storage vessel is unloaded less frequently than monthly, the throughput and separator pressure monitoring shall be conducted before the storage vessel is unloaded;

(2) conduct an AVO inspection on a weekly basis. If the storage vessel is unloaded less frequently than weekly, the AVO inspection shall be conducted before the storage vessel is unloaded;

(3) inspect the vessel monthly to ensure compliance with the requirements of 20.2.50.123 NMAC. The inspection shall include a check to ensure the vessel does not have a leak;

(4) scan the EMT and enter the required monitoring data in accordance with the requirements of 20.2.50.112 NMAC;

(5) comply with the monitoring requirements in 20.2.50.115 NMAC if using a control device to comply with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC; and

(6) comply with the monitoring requirements in 20.2.50.112 NMAC.

E~~D~~. Recordkeeping requirements:

(1) The owner or operator shall, on a monthly basis, maintain a record in accordance with 20.2.50.112 NMAC for a storage vessel. The record shall include:

(a) the vessel location and identification number;

(b) monthly liquid throughput and the most recent date of measurement;

(c) the average monthly upstream separator pressure;

(d) the data and methodology used to calculate the PTE of VOC (the calculation methodology shall be department approved);

(e) the controlled and uncontrolled VOC emissions (tpy); and

(f) the type, make, model, and identification number of any control device.

(2) A record of liquid throughput in shall be verified by a dated delivery receipt from the purchaser of the hydrocarbon liquid, the metered volume of hydrocarbon liquid sent downstream, or other proof of transfer.

(3) A record of the inspection required in Subsection C of 20.2.50.123 NMAC shall include:

(a) the time and date of the inspection;

(b) the personnel conducting the inspection;

(c) a notation that the required leak check was completed;

(d) a description of any problem observed during the inspection; and

(e) a description and date of any corrective action taken.

(4) An owner or operator complying with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(5) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

F~~E~~. **Reporting requirements:**

(1) An owner or operator complying with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.15 NMAC.

(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.123 NMAC - N, XX/XX/2021]

20.2.50.124 WELL WORKOVERS

A. **Applicability:** Workovers performed at oil and natural gas wells are subject to the requirements of 20.2.50.124 NMAC as of the effective date of this Part.

B. **Emission standards:** The owner or operator of an oil or natural gas well shall use the following best management practices during a workover to minimize emissions, consistent with the well site condition and good engineering practices:

(1) reduce wellhead pressure before blowdown to minimize the volume of natural gas vented;

(2) monitor manual venting at the well until the venting is complete; and

(3) route natural gas to the sales line, if possible.

C. **Monitoring requirements:**

(1) The owner or operator shall monitor the following parameters during a workover:

(a) wellhead pressure;

(b) flow rate of the vented natural gas (to the extent feasible); and

(c) duration of venting to the atmosphere.

(2) The owner or operator shall calculate the volume and mass of VOC vented during a workover.

(3) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. **Recordkeeping requirements:**

(1) The owner or operator shall keep the following record for a workover:

(a) identification number and location of the well;

(b) date the workover was performed;

(c) wellhead pressure;

(d) flow rate of the vented natural gas to the extent feasible, and if measurement of the flow rate is not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation;

(e) duration of venting to the atmosphere;

(f) description of the management practices used to minimize release of VOC before and during the workover; and

(g) calculation of the VOC emissions vented during the workover based on the duration, volume, and mass of VOC.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements

(1) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

(2) If it is not feasible to prevent VOC emissions from being emitted to the atmosphere from a workover event, the owner or operator shall notify by certified mail all residents located within one-quarter mile of the well of the planned workover at least three calendar days before the workover event.

[20.2.50.124 NMAC - N, XX/XX/2021]

20.2.50.125 SMALL BUSINESS FACILITIES

A. Applicability: Small business facilities as defined in this Part are subject to the requirements of 20.2.50.125 NMAC.

B. General requirements:

(1) The owner or operator shall ensure that all equipment is operated and maintained consistent with manufacturer specifications, and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available to the department upon request.

(2) The owner or operator shall calculate the VOC and NO_x emissions from the facility on an annual basis. The calculation shall be based on the actual production or processing rates of the facility.

(3) The owner or operator shall maintain a database of company-wide VOC and NO_x emission calculations for all subject facilities and associated equipment and shall update the database annually.

(4) The owner or operator shall comply with Paragraph (10) of Subsection A of 20.2.50.112 NMAC if requested by the department.

C. Monitoring requirements: The owner or operator shall comply with the requirements in Subsections C or D of 20.2.50.116 NMAC.

D. Repair requirements: The owner or operator shall comply with the requirements of Subsection E of 20.2.50.116 NMAC.

E. Recordkeeping requirements: The owner or operator shall maintain the following electronic records for each facility:

(1) annual certification that the small business facility meets the definition in this Part;

(2) calculated VOC and NO_x emissions from each facility and the company-wide VOC and NO_x emissions for all subject facilities;

(3) records as required under Subsection F of 20.2.50.116 NMAC.

F. Reporting requirements: The owner or operator shall submit to the department an initial small business certification within sixty days of the effective date of this Part, and by March 1 each calendar year thereafter. The certification shall be made on a form provided by the department. The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

G. Failure to comply with 20.2.50.125 NMAC: Notwithstanding the provisions of Section 20.2.50.125 NMAC, a source that meets the definition of a small business facility can be required to comply with the other Sections of 20.2.50 NMAC if the Secretary finds based on credible evidence that the source (1) presents an imminent and substantial endangerment to the public health or welfare or to the environment; (2) is not being operated or maintained in a manner that minimizes emissions of air contaminants; or (3) has violated any other requirement of 20.2.50.125 NMAC.

[20.2.50.125 NMAC - N, XX/XX/2021]

20.2.50.126 PRODUCED WATER MANAGEMENT UNITS

A. Applicability: Produced water management units as defined in this Part are subject to 20.2.50.126 NMAC and shall comply with these requirements no later than 180 days after the effective date of this Part.

B. Emission standards:

(1) The owner or operator shall use best management and good engineering practices to minimize emissions of VOC from produced water management units.

(2) The owner or operator shall control VOC emissions from each produced water management unit to less than two tons per year.

C. Monitoring requirements: The owner or operator shall:

(1) calculate the monthly rolling 12-month total of VOC emissions in tons from each unit;

(2) monthly, monitor the best management and engineering practices implemented to reduce emissions at each unit to ensure their effectiveness; and

(3) comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain the following electronic records for each produced water management unit:

(a) name or identification of the unit and UTM coordinates of the unit and county;

(b) a description of the best management and engineering practices used to minimize release of VOC at the unit; and

(c) a record of the monthly rolling 12-month total VOC emissions from each unit.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.126 NMAC - N, XX/XX/2021]

20.2.50.127 PROHIBITED ACTIVITY AND CREDIBLE INFORMATION PRESUMPTION

A. Failure to comply with the emissions standards, monitoring, recordkeeping, reporting or other requirements of this Part within the timeframes specified shall constitute a violation of this Part subject to enforcement action under Section 74-2-12 NMSA 1978.

B. If credible information obtained by the department indicates that a source is not in compliance with the provisions of this Part, the source shall be presumed to be in violation of this Part unless and until the owner or operator provides credible evidence or information demonstrating otherwise.

C. If credible information provided to the department by a member of the public indicates that a source is not in compliance with the provisions of this Part, the source shall be presumed to be in violation of this Part unless and until the owner or operator provides credible evidence or information demonstrating otherwise.

[20.2.50.127 NMAC - N, XX/XX/2021]

HISTORY OF 20.2.50 NMAC: [**RESERVED**]

CLEAN AIR ADVOCATES' EXHIBIT 2

David C. McCabe
Atmospheric Scientist
Clean Air Task Force
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626-710-6542

EDUCATION

Ph.D. — University of Colorado — 2004

Physical Chemistry, with research focused on Atmospheric Kinetics
Research: Vibrational Quenching Kinetics of the OH radical
Advisor: A.R. Ravishankara (NOAA)

A.B. — University of Chicago — 1994

Chemistry; also fulfilled requirements for A.B. in Geography
General Honors and Honors in Chemistry

PROFESSIONAL EXPERIENCE

Atmospheric Scientist — Clean Air Task Force — 2010 - present

Coordinate research on methane emissions from oil and gas operations in United States; Analyze US emissions data to understand uncertainties in current emissions inventories and the differences between official inventories and findings from ambient air measurements; Coordinate with advocacy staff at CATF and partner groups to develop policy goals and prepare technical information for legal, advocacy, and public outreach materials.

AAAS Science & Technology Policy Fellow — US EPA Office of Research and Development — 2007 - 2009

Coordinated and promoted work at US EPA and elsewhere to develop GEOSS, a global effort to improve Earth science data availability and usability.

Postdoctoral Research Fellow — California Institute of Technology — 2004 - 2007

Research: Built and operated an aircraft-based chemical ionization mass spectrometry system to measure trace species (acids and peroxides) in the remote and polluted troposphere
Advisor: Paul Wennberg

SELECTED REFEREED PUBLICATIONS

Weyant, C.L., P.B. Shepson, R. Subramanian, M.O.L. Cambaliza, A. Heimburger, D. **McCabe**, *et al.* (2016) "Black Carbon Emissions from Associated Natural Gas Flaring," *Environ. Sci. Technol.* **50**, 2075, doi:10.1021/acs.est.5b04712.

Kleinman, M.T., J.D. Bachmann, H.J. Feldman, D. **McCabe**, J.J. West, and A.F. Fiore (2015) "Connecting air quality and climate change," *J. Air Waste Manage*. **65**, 1283, doi: 10.1080/10962247.2015.1095599.

Swarthout, R.F., R.S. Russo, Y. Zhou, B.M. Miller, B. Mitchell, E. Horsman, E. Lipsky, D.C. **McCabe**, *et al.* (2015) "Impact of Marcellus Shale natural gas development in southwest Pennsylvania on volatile organic compound emissions and regional air quality." *Environ. Sci. Technol.* **49**, 3175, doi:10.1021/es504315f.

Caulton, D.R., P.B. Shepson, M.O.L. Cambaliza, D. **McCabe**, E. Baum, and B.H. Stirm (2014) "Methane destruction efficiency of natural gas flares associated with shale formation wells," *Environ. Sci. Technol.* **48**, 9548, doi:10.1021/es500511w.

St. Clair, J.M., D.C. **McCabe**, J.D. *et al.* (2010) "Chemical ionization tandem mass spectrometer for the in situ measurement of methyl hydrogen peroxide," *Rev. Sci. Instru*. **81**, 094102, doi:10.1063/1.3480552.

Avery, M., C. Twohy, D. **McCabe**, *et al*. (2010) "Convective distribution of tropospheric ozone and tracers in the Central American ITCZ region: Evidence from observations during TC4," *J. Geophys. Res*., **115**, D00J21, doi:10.1029/2009JD013450.

Spencer, K.M., D.C. **McCabe**, *et al.* (2009) "Inferring ozone production in an urban atmosphere using measurements of peroxynitric acid," *Atmos. Chem. Phys*., **9**, 3697, doi:10.5194/acp-9-3697-2009.

McCabe, D.C., *et al.* (2006) "The relaxation of OH (v = 1) and OD (v = 1) by H_2O and D_2O at temperatures from 251 to 390 K," *Phys. Chem. Chem. Phys.*, **8**, 4563, doi:10.1039/B609330B.

McCabe, D.C., *et al.* (2003) "Kinetics of the Removal of OH (v = 1) and OD (v = 1) by HNO_3 and DNO_3 from 253 to 383 K," *J. Phys. Chem. A*, **107**, 7762, doi:10.1021/jp0346413.

McCabe, D.C., T. Gierczak, R.K. Talukdar, and A.R. Ravishankara (2001) "Kinetics of the reaction OH + CO under atmospheric conditions," *Geophys. Res. Lett.*, **28**, 3135, doi:10.1029/2000GL012719.

SELECTED CONFERENCE PRESENTATIONS (ORAL AND POSTER)

Fleischman, L., **D. McCabe**, D. Lyon, M. D'Antoni, J. Anhalt, "Tank Emissions from Controlled Tanks," Stakeholder Workshop on EPA GHG Data for Petroleum and Natural Gas Systems, Oct. 2017, Houston, TX.

Field, R., J. Soltis, D. Snare, R. Edie, D. **McCabe**, S. Murphy, "Reconciling Airborne Basin Scale Methane Flux Estimates with Ground Based Quantification of Methane and VOC Emissions from Well Pads," American Geophysical Union Fall Meeting, Presentation A11L-03, Dec. 2014, San Francisco, CA, USA.

McCabe, D.C., E. Baum, S. Saunier, "Quantifying Methane Mitigation Costs from US Oil and Natural Gas," Air and Waste Management Association, Climate Change: Impacts, Policy, and Regulation Conference, Presentation 11, Sept. 2013, Herndon, VA, USA.

McCabe, D., P. Groisman, *et al*., "Open Burning and the Arctic: Current Knowledge and Priorities for Future Research," European Geophysical Union General Assembly 2011, Presentation EGU2011-12855, Apr. 2011, Vienna, Austria.

Dickerson, P., J. Szykman, D. **McCabe**, "Integrating Satellite Observations into AIRNow: Providing Real Time Air Quality and Forecasts in the US and Elsewhere," CEOS Atmospheric Composition Constellation Workshop on Air Quality, June 2009, Frascati, Italy.

McCabe, D.C., *et al.*, "Measurements of Isotopic Composition of Water Vapor Using CIMS From the NASA DC-8 During TC4," American Geophysical Union Fall Meeting, Presentation A31C-0114, Dec. 2008, San Francisco, CA, USA.

PROFESSIONAL ACTIVITIES

Expert Testimony

Colorado Air Quality Control Commission, Oil and Gas Rulemakings, February 2014 and October 2017

Invited Reviewer

Referred Journals: *Environmental Science and Technology, Atmospheric Chemistry and Physics, Environmental Research Letters, Journal of Industrial Ecology*

EPA's *Methodologies for U.S. Greenhouse Gas Emissions Projections: Non-CO_2 and Non-Energy CO_2 Sources*, Natural Gas Systems and Petroleum Systems Sections, 2013, 2014.

EPA's *Global Mitigation of Non-CO_2 Greenhouse Gases*, Natural Gas and Oil Systems Section, 2013.

EPA's *Inventory of US Greenhouse Gas Emissions and Sinks.* 2013 – 2018.

CLEAN AIR ADVOCATES' EXHIBIT 3

STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC – *Oil and Gas Sector – Ozone Precursor Pollutants* **No. EIB 21-27 (R)**

DIRECT TESTIMONY OF DAVID MCCABE, PH.D.

Q: Please state your name.

A: My name is Dr. David McCabe.

Q: What is your educational background?

A: I have a Bachelor of Arts in chemistry from the University of Chicago, and a Ph.D. in physical chemistry from the University of Colorado.

Q: What is your work background?

A: I am an atmospheric scientist with the Clean Air Task Force (CATF). I have ten years of experience studying emissions controls for the oil and gas sector. I have designed several studies on emissions of air pollutants from oil and gas facilities, and I am a co-author on a number of peer-reviewed publications describing those studies and their findings. I have provided expert advice on technical comments submitted on oil and gas emissions controls and waste prevention measures proposed by the U.S. Environmental Protection Agency (EPA), the Bureau of Land Management, the states of California, Pennsylvania, and Colorado, and internationally in Mexico and Canada. Here in New Mexico, I presented to the Methane Advisory Panel in 2019, and also testified before the Oil Conservation Commission earlier this year regarding the waste prevention rule. My curriculum vitae is attached as Clean Air Advocates' Exhibit 2.

Q: What is Clean Air Task Force?

A: CATF is a nonprofit organization dedicated to reducing atmospheric pollution through research and analysis, public advocacy leadership, and partnership with the private sector.

CATF also works to safeguard against the worst impacts of climate change by catalyzing the rapid global development of low carbon energy and other climate-protecting technologies. CATF staff consists of senior engineers, MBAs, scientists, attorneys, and communications specialists. Our record of providing non-partisan, data-driven analysis helps identify and defend policy designs that will achieve the greatest climate benefit at the least cost. An American Association for the Advancement of Science publication has called CATF "a well-respected public health and environment advocacy group."

Q: Dr. McCabe, can you please summarize the opinions you will give in your testimony?

A: My testimony addresses two sections of the rule: proposed 20.2.50.122 NMAC, which sets forth proposed regulations for pneumatic devices, and proposed 20.2.50.123 NMAC, which sets forth proposed regulations for storage vessels.

With respect to pneumatic devices, I explain why Clean Air Advocates support the New Mexico Environment Department's (NMED) proposals (1) to immediately require the use of zero-emission pneumatic controllers at all new sites and all sites that have access to electricity and (2) to replace pneumatic controllers that are designed to emit air pollutants with zero-emission alternatives. I further explain that we propose to strengthen NMED's proposal and make it more effective. In general, we propose modeling New Mexico's rule after one recently adopted in Colorado, with the support of the oil and gas industry. Among other things, we proposethat operators be required to achieve a fixed *increase* in the percentage of non-emitting controllers, rather than reaching a fixed end point. This makes the rule more effective, more equitable, and less arbitrary. We also propose that the transition to zero-emission pneumatics occur more rapidly than NMED has proposed, to ensure that New Mexico is not needlessly delaying the important environmental benefits that can be obtained by transitioning to zero-emission controllers.

With respect to storage vessels, I explain why Clean Air Advocates propose to require use of a "storage vessel measurement system" for storage vessels installed at new or modified facilities. Operators must frequently measure and sample the liquids inside a storage vessel. Typically, operators open a hatch on the vessel, releasing significant quantities of volatile organic compounds (VOCs) and methane, in order to conduct these measurements. Our proposal would eliminate these emissions by requiring operators to employ an alternative system that allows for measurement and sampling without venting (for example, implementation of Chapter 18.2 of American Petroleum Institute's Manual of Petroleum Measurement Standards, or installation of a Lease Automatic Custody Transfer unit). Our proposal is basically identical to an amendment adopted by the Colorado Air Pollution Control Division in December 2019, which the Division found to be cost-effective and which has been implemented without difficulty.

PNEUMATIC DEVICES

Q: Dr. McCabe, what are pneumatic controllers?

A: Pneumatic controllers are a type of process controller. A process controller is a device that senses a physical state and then operates automatically to regulate that state. Process controllers can regulate a variety of physical parameters—or process variables—including fluid pressure, liquid level, fluid temperature, and differential pressure. Process controllers can be electric, hydraulic, pneumatic, mechanical, or a combination of these.

A pneumatic controller is a type of process controller that uses gas pressure to open or close a mechanical device, such as a valve, when it senses the need to regulate a process condition such as liquid level, pressure, temperature, or flow. Historically, most pneumatic controllers at oil and natural gas sites were operated with pressurized natural gas, exploiting the pressure energy present in that natural gas. Thus, these controllers were configured to release the natural gas, and the pollutants it contains, into the atmosphere as they operated. Increasingly, operators are shifting to zero-emission alternatives that perform the same function, using electricity or compressed "instrument" air. Accelerating this transition can provide important environmental and public health benefits.

Q: How are pneumatic controllers used in oil-and-gas operations?

A: Pneumatic controllers are used to automate and control various process throughout the oil-and-gas industry. These controllers are used at wellsites, gathering and boosting stations, transmission compressor stations, and gas-processing plants. An example of a common usage is a separator dump valve controller, which causes a dump valve to open when it senses that liquid in the separator has reached a certain level.

Q: Are there different types of natural gas-driven pneumatic devices?

A: Yes, natural gas-driven pneumatic devices may be either *continuous bleed*, which means they emit gas continuously by design, or they may be *intermittent bleed*, which means they are designed to emit gas only when they actuate. Continuous-bleed pneumatic devices are classified as high-bleed if they are designed to emit more than 6 standard cubic feet per hour (scfh), or low-bleed if they are designed to emit less than this amount.

Q: Do pneumatic controllers emit air pollutants?

A: Yes, they do, if they are operated with natural gas. Natural gas is primarily composed of methane, a potent greenhouse gas. Other pollutants, including ozone-forming VOCs and toxic or cancer-causing hazardous air pollutants (HAPs) are typically present in natural gas at sites such as well production facilities, gathering compressor stations, and processing plants. Pneumatic controllers are designed to release the gas that is used to operate them, and typically are configured to release that gas directly into the atmosphere. When natural gas is used to operate controllers, that natural gas (and the air pollutants it contains) is emitted into the atmosphere.

Unfortunately, this is not the only reason that pneumatic controllers emit VOCs and other pollutants that are present in natural gas. Pneumatic controllers often malfunction, and as a result emit more natural gas than they are designed to emit. For example, intermittent-bleed controllers, which are the most common type in New Mexico, are designed to emit only during the actuation cycle for the controller, but in the field, these devices frequently emit between actuations. It is well documented that these problems are widespread:

- A field study carried out in the Denver-Julesburg basin Colorado in 2018 found that 5.6% of the inspected intermittent controllers were operating improperly. Pneumatic Controller Task Force Report to AQCC, CO Air Pollution Control Div., Dept. of Public Health and Env't. (June 1, 2020) (Colorado APCD Task Force Report) [Clean Air Advocates' Ex. 8].
- Stovern et al. also studied pneumatic controllers in the Denver-Julesburg basin in 2018. This study directly observed that 11.3% of the intermittent controllers were emitting continuously, due to a maintenance issue. However, the study notes that due to methodological issues, this 11.3% figure is probably an underestimate of the actual rate of malfunction among the intermittent controllers they inspected. They estimate that the true rate of malfunction in their sample was 11.6 to 13.6%.[1]

[1] Michael Stovern *et al*., *Understanding oil and gas pneumatic controllers in Denver-Julesburg basin using optical gas imaging*, 70 J. of the Air & Waste Management Assoc. at 9 (2020), https://doi.org/10.1080/10962247.2020.1735576.

- Luck et al. extensively measured emissions from 72 controllers at 16 natural gas compressor stations, recording consumption of gas by the controllers for multi-day periods. They found that a very large portion of controllers were operating abnormally, leading to emissions substantially higher than emissions from normal operating controllers. Of the overall pool of controllers, 42% were operating abnormally. Of the 40 intermittent controllers they studied, 25 (63%) were operating abnormally.[2]
- Allen et al. concluded that among controllers with the highest emissions rate, many suffered from easily reparable issues, and "many of the devices in the high emitting group were behaving in a manner inconsistent with the manufacturer's design."[3]
- A City of Fort Worth study that examined emissions from 489 intermittent-bleed devices using infrared cameras and other methods found that many controllers were emitting constantly and at very high rates, even though they were being used to operate separator dump valves and were not designed to emit between actuations.[4]

At the same time, a number of studies have documented problems with low-bleed controllers, the second most common type of controller. Low-bleed controllers emit

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[2] Benjamin Luck *et al.*, *Multiday Measurements of Pneumatic Controller Emissions Reveal the Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations,* Environ. Sci. Technol. Letters 6, 348–52 (2019). https://pubs.acs.org/doi/10.1021/acs.estlett.9b00158.

[3] David T. Allen, et al., *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers*, 49 Envtl. Sci. Tech. 633 (2015), http://pubs.acs.org/doi/abs/10.1021/es5040156, at 639.

[4] E. Research Grp., Inc. & Sage Envtl. Consulting, LP, *City of Fort Worth Natural Gas Air Quality Study* at 3-100 (July 13, 2011), https://www.fortworthtexas.gov/files/assets/public/development-services/documents/gaswells/ergreport-section-3.pdf ("Under normal operation a pneumatic valve controller is designed to release a small amount of natural gas to the atmosphere during each unloading event. Due to contaminants in the natural gas stream, however, these controllers eventually fail (often within six months of installation) and begin leaking natural gas continually.").

continuously by design. Additionally, they often do not function as designed or otherwise emit more than designed: a significant number of controllers designated as low-bleed by operators or manufacturers have been observed to emit above the 6 scfh threshold which is defined as the upper limit for acceptable emissions from low-bleed controllers. For example, the 32 pneumatic controllers measured by Allen et al. (2015) which operators categorized as "low-bleed" had an average emissions rate of 10.8 scfh,[5] clearly indicating that many low-bleed controllers emit over 6 scfh. An earlier study by Allen et al. published in 2013 reported a lower emissions factor for low-bleed controllers (5.1 scfh),[6] but that emissions factor indicates that some low-bleed controllers emit over 6 scfh, since presumably some controllers emit lower amounts consistent with the low bleed rates (~3 scfh or less) specified for many controllers.

Q: What do we know about the extent of emissions from pneumatic controllers at oil and gas facilities?

A: Given the extent to which pneumatic devices malfunction and emit more than they are designed to emit, it is difficult to precisely quantify emissions from these devices. However, based on our analysis of data collected for the Permian and San Juan basins in EPA's Greenhouse Gas Reporting program, we estimate that there are over 118,000 pneumatic controllers in New Mexico that collectively emit about 108,000 metric tons of methane.[7] These

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[5] Based on analysis by CATF of Table S4-1 in the Supporting information for Allen et al (2015), *supra* n.4.

[6] David T. Allen, et al., *Measurements of methane emissions at natural gas production sites in the United States*, 110 Proc. Natl. Acad. Sciences (USA) 17768 (2013), www.pnas.org/cgi/doi/10.1073/pnas.1304880110.

[7] Analysis by Clean Air Task Force of USEPA Greenhouse Gas Reporting Program (GHGRP) data. Since GHGRP data for pneumatic controllers at production or gathering and boosting facilities is only provided at the production basin level, and both the Permian and San Juan basins extend beyond New Mexico's borders, we reduced the counts and emission volumes for pneumatic controllers for each basin by the fraction of wells in each basin that are in New Mexico. Since smaller operators do not report emissions (or equipment counts) to GHGRP, the figures are underestimates.

devices emit an estimated 30,000 metric tons of VOC.[8] Analysis from the Environmental Defense Fund indicates that pneumatic devices are the second largest source of methane emissions from the oil and gas industry in New Mexico.[9]

Q: Can pneumatic controllers that emit methane and VOCs be replaced with controllers than do not emit at all?

A: Yes. Several cost-effective technologies are available that can *entirely eliminate* emissions from gas-driven pneumatic controllers, at new and existing sites, *with and without electricity available*. These options were mapped out in a report that Clean Air Task Force published a few years ago, which we have submitted as Clean Air Advocates' Exhibit 4 [Carbon Limits (2016), *Zero emission technologies for pneumatic controllers in the USA*].[10] I will briefly summarize the findings of that report here, including some updates to the report.

One approach is to use compressed air instead of pressurized natural gas to operate controllers. These compressed air systems are often referred to as "instrument air" systems and they have been in use at oil and gas sites for years. Recently, several systems for utilizing solar power to compress air on well-pads with no other available electrical power have come to the market.[11]

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[8] Analysis by Clean Air Task Force of GHGRP data. VOC volume was estimated by multiplying the methane volumes presented above by standard VOC/methane ratios US EPA has used in rulemaking analyses. *See* U.S. EPA. "Regulatory Impact Analysis Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry" (July 2011) Table 3-3. Available at: https://www3.epa.gov/ttn/ecas/regdata/RIAs/oilnaturalgasfinalria.pdf.

[9] EDF, New Mexico Oil & Gas Data, https://www.edf.org/nm-oil-gas/emissions/.

[10] Available at https://www.catf.us/resource/zero-emission-technologies-for-pneumatic-controllers-usa/.

[11] See for example: https://www.airworkscompressors.com/aurora-instrument-air-package/; https://westgentech.com/epod/; and https://lcotechnologies.com/products-crossfire.html.

A second approach is to use electric controllers, avoiding the use of pneumatic operation. Electric controllers suitable for solar power/battery systems have been developed for the upstream oil and gas industry.[12] As discussed in the New Mexico Methane Advisory Panel Report, solar-powered pneumatic devices are a technically and economically feasible alternative to continuous-bleed devices.[13] These systems have been proven in production regions of Alberta—a location far harsher for utilization of solar than New Mexico.[14] Calscan, an Alberta vendor of packages that utilize solar-power and batteries to power electric actuators and instrumentation for zero emission separators,[15] estimates that it has sold about 400 of these packages in Canada (mainly in Alberta).[16]

Instrument air systems and electric controllers have been implemented widely in British Columbia (BC) and Alberta in particular. A 2018 study provides useful data on the penetration of these technologies at wellsites in BC. Cap-On British Columbia Oil and Gas Methane Emissions Field Study (2019) [Clean Air Advocates' Ex. 7.] The study provides statistics on controllers and pumps at over 260 production sites (well pads and tank batteries) in BC. The study counted 2,120 controllers and pumps at these sites. Notably, more controllers and pumps at these sites were air-driven (891 units, 42%) than natural gas-driven (725 units, 34%). Additionally, the study noted that electric controllers and pumps were also widespread (419 units, 20%). Solar-powered pumps (59 units, roughly 15% of all pumps) were also present in significant numbers. (Note that solar-pumps were a separate category from electric pumps and

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[12] See for example http://www.calscan.net/products_bearcontrol.html, and more generally, Carbon Limits (2016), Section 3.2 [Clean Air Advocates' Ex. 4].

[13] MAP Report at 19, 23.

[14] See Colorado APCD Task Force Report at 37-38 [Clean Air Advocates' Ex. 8] and Carbon Limits (2016) at 15 (footnote 6) [Clean Air Advocates' Ex. 4].

[15] *See* Calscan, *Zero GHG Venting Controls for Separators*, http://www.calscan.net/solutions_ZeroGHGVenting.html (last visited July 24, 2021).

[16] Conversation with Henri Tessier, Calscan (Oct. 30, 2020).

that only integrated solar equipment was classified as "solar" in this study.) Instrument air was very common (more than 50% of units) for level controllers, transducers, pressure controllers, and positioners. Electric controllers account for more than 50% of units for level switches and high-level shut downs, and over 30% of pumps (in addition to the 15% of pumps that are integrated solar pumps).

In short, multiple vendors provide zero-emission alternatives to gas-driven controllers, and numerous operators are using them on (at least) hundreds of sites in the United States and Canada. Carbon Limits accordingly concluded that "[o]verall . . . zero-emission solutions are available today and are cost-effective to implement in nearly every situation."[17]

Q: In general, is retrofitting natural-gas driven pneumatic controllers with zero-emission alternatives a cost-effective method for reducing emissions?

A. Yes. We conducted analysis as part of a recent rulemaking in Colorado that demonstrated that the use of these technologies, instead of gas-driven controllers, at new and existing well-pads and compressor stations is a cost-effective mitigation approach for reducing VOC and methane emissions. *See* Conservation Groups' Initial Economic Impact Analysis. (2020) [Clean Air Advocates' Ex. 5]. In order to facilitate calculation of the costs and benefits of retrofitting sites with non-emitting controllers, Carbon Limits also created a spreadsheet tool that can be used to calculate cost at a given site. This tool is attached as Exhibit 6..

This conclusion is well supported by a number of recent regulations that prohibit installation of new gas-driven pneumatic controllers (unless their emissions are captured/controlled) at certain facilities:

[17] Carbon Limits (2016) at 4 [Clean Air Advocates' Ex. 4].

- **Alberta** will prohibit the installation of any new gas-driven pneumatic controllers that vent to the atmosphere, beginning on January 1, 2022.[18]

- **British Columbia** prohibits the use of any venting pneumatic controller at any new site, effective January 1, 2021.[19]

- Earlier this year, **Colorado's** Air Quality Control Commission approved a rule that prohibits installation of any venting controllers at all new or modified facilities statewide after May 1, 2021, and requires operators to replace a significant portion of venting gas-driven controllers at existing facilities statewide.[20] An existing well pad will be considered to be "modified" if a new well is drilled or an existing well is re-completed. I discuss the Colorado retrofit program in more detail below.

- Finally, **California** prohibited installation of new continuous-bleed controllers (whether "high-bleed" or "low-bleed") several years ago.[21] However, considering that intermittent-bleed controllers are far more common than continuous bleed controllers, and the fact that zero-emitting technologies such as utilizing instrument air or solar-generated electricity can be used to replace intermittent-bleed controllers, the California approach is not adequate.

Q: Please describe the retrofit program for venting pneumatic controllers required by Colorado's Air Quality Control Commission's regulations.

A: Colorado's Air Quality Control Commission's regulations for pneumatic controllers at well production facilities and gathering compressor stations require operators to retrofit a substantial portion of facilities to use non-emitting controllers over

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[18] Alberta Energy Regulator, Directive 060, § 8.6.1. Available at https://static.aer.ca/prd/2020-10/Directive060.pdf.

[19] B.C. Rule § 52.05. Available at https://www.canlii.org/en/bc/laws/regu/bc-reg-282-2010/latest/bc-reg-282-2010.html.

[20] 5 Colo. Code Regs. § 1001-9:D.III.C.4. Note that the rules allow operators to install venting controllers if necessary "for a safety or process purpose." 5 Colo. Code Regs. § 1001-9:D.III.C.4.e(i)(A). We do not expect operators to attempt to utilize that provision with any frequency, based on past implementation of other pneumatics provisions of Colorado's air quality regulations. For example, see McCabe et al. (2014), *Waste Not: Common Sense Ways to Reduce Methane Pollution from the Oil and Natural Gas Industry,* https://www.catf.us/resource/waste-not-reduce-methane-pollution at 26 (documenting that no operator even requested an exemption under a similar provision in a parallel Colorado regulation that required replacement of high-bleed controllers).

[21] Cal. Code Regs. tit. 17, § 95668(e)(2).

the next 2 years. The programs are somewhat complex; my description is only a general overview. The program is designed somewhat differently for well production facilities and for gathering compressor stations. I will describe the gathering compressor station rules first.

Upon passage of the rule, each operator of gathering compressor stations in Colorado was required to determine the aggregate number of emitting and non-emitting controllers it was operating at the time at all of its compressor stations in the state. Operators then determined what percentage of their controllers were non-emitting (this value is referred to as the "Total Historic Percentage of Non-Emitting Controllers," below I refer to this as the "Historic Percentage" for brevity). Operators are grouped into cohorts according to their Historic Percentage, and each operator is required to comply with a schedule for replacement of venting controllers with non-emitting controllers, with requirements to replace a fixed portion of venting controllers by May 1, 2022, and a second fixed portion of venting controllers by May 1, 2023. The portion of venting controllers each operator is required to replace for each deadline is determined by the operator's Historic Percentage cohort: Operators in lower cohorts (with lower portions of non-emitting controllers today) need to replace higher portions of controllers, but all operators have to replace some controllers, unless they have already eliminated emitting controllers at their gathering compressor stations.

For example, operators with Historic Percentages of 0-20% are required to retrofit 20% of their controllers, statewide, to non-emitting controllers by May 1, 2022, and to retrofit an additional 25% of controllers to non-emitting controllers by May 1, 2023. So, an operator which had 10% non-emitting controllers at the passage of the rule must convert additional controllers so that their fleet is 30% non-emitting controllers by May 1, 2022 and 55% non-emitting controllers by May 1, 2023. However, no operator in this cohort is required to go beyond 35% non-emitting by the 2022 deadline, or 60% non-emitting by the 2023 deadline.

Oil and gas producers are also required to convert to non-emitting controllers according to a schedule, with the same timelines, and a similar cohort structure requiring operators with lower portions of non-emitting controllers at the time the rule was passed to replace a higher portion of their controllers than operators who had more non-emitting controllers at that time (but all operators need to replace a portion of their controllers, unless they are at a very high level of non-emitting controllers). However, for oil and gas production, the rules do not require operators to retrofit a given percentage of their inventory of controllers. Instead, operators are required to retrofit a portion of their *facilities*, converting all controllers (with limited exceptions) at the retrofitted facilities to non-emitting devices. Specifically, operators must convert facilities that account for a certain percentage of the operator's *total liquids production* (liquid hydrocarbons plus produced water) in the state by each date. For example, an operator that currently produces 10% of its statewide liquids at well pads with no emitting pneumatics must convert well pads that account for 15% of the operator's total statewide liquids to non-emitting by May 1, 2022, and then must convert additional well pads that account for 25% of the operator's total statewide liquids to non-emitting by May 1, 2023.

The rules that NMED has proposed have a similar structure, with important differences we discuss below.

Q: What is NMED's current proposal at 20.2.50.122 NMAC with respect to requiring operators to retrofit pneumatic controllers?

A: NMED has proposed several provisions that would require operators to replace venting gas-driven controllers at existing oil and natural gas facilities.

First, at sites with commercial line electrical power, NMED requires that pneumatic controllers have an emission rate of zero. Operators of these sites must convert any emitting controllers to instrument air, electric controllers/actuators, capture emissions from controllers, or otherwise prevent emissions. My understanding is that NMED intends for retrofits at these sites to occur upon the effective date of the rule.

Second, and most important, NMED requires operators of sites without commercial line electrical power to convert a portion of their fleets of pneumatic controllers to non-emitting controllers (i.e., air-driven or electric controllers). Operators are required to convert controllers according to two schedules provided in the proposal. One schedule applies to production facilities and gathering compressor stations. The second schedule applies to gas processing plants and transmission compressor stations. Both schedules require operators to increase portions of their fleets by three deadlines: January 1, 2024, January 1, 2027, and January 1, 2030.

For both schedules, the portion of controllers that operators are required to convert to non-emitting technologies depends upon the portion of the operator's controllers that are already non-emitting. Under this approach, all operators (with the exception of those that already have a very high portion of controllers that are non-emitting) are required to convert a significant number of their controllers to non-emitting technology, but as the fraction of non-emitting controllers an operator already utilizes increases, the portion that the operator needs to convert by each deadline decreases. This is a logical approach because operators with a lower fraction of non-emitting controllers have more controllers that are still emitting harmful pollutants, so they should be moving faster to convert them to zero-emitting.

Q: Do you support the goal of 20.2.50.122 NMAC of replacing emitting pneumatic controllers with zero-emission controllers?

A: Yes. As discussed above, our analysis has shown that utilizing electric controllers and instrument air systems, instead of gas-driven controllers, at new and existing well pads and compressor stations is a cost-effective mitigation approach for reducing VOC and methane emissions.

Q: Clean Air Advocates have proposed changes to NMED's approach to make it more effective and to accelerate the schedule, correct?

A: Correct. Our approach differs from the approach taken in the NMED proposal in several important ways. First, we propose that any gas driven controllers at gas processing plants or transmission compressor stations should be converted to non-emitting within six months. Under our proposal, Table 2 of 20.2.50.122 NMAC (regulating gas processing plants and transmission compressor stations) is unneeded.

Second, we propose to require operators in each cohort to *increase their fraction of non-emitting controllers by a fixed percentage,* rather than requiring all operators in each cohort to increase their fraction of non-emitting controllers *to* a fixed percentage.

Third, our proposal would accelerate the compliance timeline, while setting two deadlines (May 1, 2023 and May 1, 2025) instead of three deadlines in the NMED proposal (January 1, 2024, January 1, 2027, and January 1, 2030).

Fourth, our proposal would strike the provision that would release an operator that converted 75% of its pneumatic controllers to non-emitting by January 1, 2025 from any further requirements to convert to non-emitting controllers.

Q: Why do Clean Air Advocates propose that gas driven controllers at gas processing plants or transmission compressor stations should be converted to non-emitting within six months?

A: NMED's technical analysis shows that all gas processing plants in New Mexico are already using non-emitting controllers, and all of them have access to commercial line electric power. Further, NMED's analysis finds that all transmission compressor stations have access to electric power. Assuming this is accurate, all transmission compressor stations would be required to convert to zero-emitting technologies under NMED's proposed 20.2.50.122.B(4)(b) NMAC. In other words, under NMED's proposal, all pneumatic devices at transmission compressor stations and gas processing plants would be zero-emitting upon the effective date of the rule. We support this outcome, but believe the rule should be clarified so that all stakeholders understand that all controllers at these facilities must be non-emitting, and to give operators with venting gas-driven controllers at transmission compressor stations adequate time to convert them to non-emitting.

Additionally, based on my professional experience working with activity data for midstream facilities from several states, I believe that NMED's inventory and knowledge of these facilities could be incomplete.[22] If this should be the case, there may be processing plants or transmission compressor stations that currently have venting gas-driven pneumatics but do not have access to commercial electric power. These facilities can still convert quickly and easily to a non-emitting technology and should be required to do so.

NMED's proposed approach would give operators of these facilities many years to only partially convert controllers at these facilities (following Table 2 of proposed 20.2.50.122 NMAC). There is no need to wait years to convert these large facilities, which typically use instrument air systems, to non-emitting controllers. For example, in December 2017, Colorado

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[22] For example, see the discussion of the challenges in producing complete lists of midstream facilities in Anthony J. Marchese *et al.*, "Methane Emissions from United States Natural Gas Gathering and Processing," *Environ. Sci. Technol*. 49, 10718−10727 (2015). https://pubs.acs.org/doi/10.1021/acs.est.5b02275.

required operators of gas processing plants in the Front Range Nonattainment Area to convert to non-emitting pneumatic controllers by May 1, 2018 (i.e., within six months).[23]

Therefore, to make the rule clearer and ensure that all processing plants and transmission compressor stations are converted to non-emitting controllers in a timely fashion, consistent with precedent from Colorado, we propose simply requiring that all of these facilities be converted to non-emitting controllers within six months. Consistent with this proposal, we propose removing Table 2, which is not needed because all facilities described in that Table 2 would need to convert to zero-emitting controllers within 6 months.

Q: Why are Clean Air Advocates proposing that each operator be required to achieve a particular *increase* in the percentage of zero-emission controllers, as opposed to requiring that operators achieve a particular *percentage*?

A: Requiring operators to achieve a fixed percentage, no matter where they lie within their cohort, is less efficient, less equitable for operators, and creates arbitrary outcomes. For example, under Table 1 as proposed by NMED, an operator starting at 19% is in the bottom cohort, meaning the operator must to get to 25% non-emitting controllers by 2024. That amounts to a 6% increase. But an operator starting at 21% is in the fourth cohort, meaning the operator must get to 45% by 2024. That's a 24% increase.

In this example, the second operator is actually cleaner to start with. Yet the operator has to replace four times as many controllers by over the next two and a half years as the first operator. In addition to being arbitrary and less fair for some operators, this structure also makes the rule less effective, because the required percentage must be feasible for an operator at the

[23] See 5 Colo. Code Regs. § 1001-9:D.III.C.2.

bottom of the cohort, greatly limiting the amount of conversion required for an operator near the top of the cohort.

Finally, the approach proposed by NMED creates an incentive for operators to undercount the number of existing pneumatic devices, or perversely, to delay retrofits so they remain in a favorable position (i.e., immediately below a threshold for inclusion in the next higher cohort).

Rather than requiring operators to achieve a fixed percentage, we propose to require operators to achieve a fixed increase in the percentage. This is the approach Colorado took in its recent pneumatic retrofit rule. Under that rule, all operators in a given cohort are subject to the same requirements. Thus, an operator that starts at 1% must convert an additional 20% of its controllers. An operator starting at 15% must also convert an additional 20%.

We further propose that, as in Colorado, New Mexico include a Maximum Required Percentage for each cohort. These maximum required percentages are needed because without them, operators at the top of a given cohort would be required to pass operators in the bottom of the next higher cohort, an arbitrary outcome. For example, under our proposal, an operator in the bottom cohort would be required to convert an additional 40% of controllers by the first deadline (May 1, 2023), while an operator in the second-to-last cohort would be required to convert 35% of controllers. This could lead to arbitrary results at the margins. For example, an operator starting at 19% non-emitting controllers would be in the bottom cohort, and thus would be required to increase the percentage of non-emitting controllers by 40%, arriving at 59%. Yet an operator starting at 21% would be in the second-to-last cohort, and required to increase its percentage by 35%, arriving at 56%. The Maximum Required Percentage table avoids this arbitrary result, by providing that no one in the bottom cohort needs to achieve a total percentage greater than 55% by the first deadline. This ensures that the rule is equitable and efficient.

Q: Why do the Clean Air Advocates propose an accelerated timeline for replacement of venting gas-driven controllers, relative to the NMED proposal?

A: Simply stated, NMED's proposed timeline is too slow, given the feasibility of the technologies for replacement of gas-driven venting pneumatic controllers, the precedent from Colorado, and the urgency to rapidly reduce methane pollution to stem the climate crisis. We propose a more aggressive program, that is consistent with the approach and level of ambition taken by Colorado.

As I have discussed above, technologies to control valves without the use of venting gas-driven controllers are well established, and in widespread use. In the context of the Colorado rulemaking, we demonstrated that retrofitting a wide swath of sites to eliminate venting gas-driven controllers would be cost-effective; NMED has also shown that their proposed approach would be cost-effective.

Recognizing this, industry, environmental organizations, local governments, and Colorado Department of Public Health and Environment negotiated and jointly proposed a set of regulations that require industry to replace a significant portion of the pneumatic controller that each firm is operating at well sites and/or gathering compressor stations. These regulations were unanimously adopted by the Colorado Air Quality Control Commission in February 2021.

As discussed above, Colorado's rules and the NMED proposal both require operators to comply with a schedule for replacing pneumatic controllers. The specific requirements for an operator depend on the fraction of the operator's valve controllers that are already non-emitting, with operators assigned to one of five cohorts determined by this fraction.

Colorado's schedule for operators of gathering compressor stations is the most direct analogue of the schedules proposed by NMED. This table (Table 2 in the Colorado rules) is reproduced here:

TABLE 2* – Natural Gas Compressor Stations					
Total Historic Percentage of Non-Emitting Controllers	**May 1, 2022 Additional Required Percentage of Non-Emitting Controllers**	**May 1, 2022 Maximum Required Percentage of Non-Emitting Controllers**	**May 1, 2023 Additional Required Percentage of Non-Emitting Controllers**	**May 1, 2023 Maximum Required Percentage of Non-Emitting Controllers**	**Total Additional Required Percentage of Non-Emitting Controllers By May 1, 2023**
> 75 %	+10%	90%	+15%	100%	+25%
>60-75 %	+10%	85%	+20%	92%	+30%
>40-60 %	+10%	70%	+25%	75%	+35%
>20-40 %	+15%	50%	+25%	65%	+40%
0-20 %	+20%	35%	+25%	60%	+45%

Here, I will focus on the conversions required by May 1, 2023 for operators with various levels of non-emitting controllers.

- An operator with no non-emitting controllers now would have to convert 45% of its controllers by May 1, 2023.
- An operator with 15% non-emitting controllers now would also have to convert an additional 45% of its controllers by May 1, 2023.
- An operator with 18% non-emitting controllers now would have to convert an additional 42% of its controllers by May 1, 2023. This operator's conversion requirement in the initial period (with the deadline of May 1, 2022) is limited by the "Maximum Required Percentage" column for that period.
- An operator with 25% non-emitting controllers now would have to convert an additional 40% of its controllers by May 1, 2023.

For convenience, I have reproduced table 1 from the NMED proposal, which I understand is to apply to gathering compressor stations, here:

Table 1 – WELLHEAD SITES, TANK BATTERIES, GATHERING AND BOOSTING FACILITIES

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
> 75 %	80%	85%	90%
> 60-75 %	80%	85%	90%
> 40-60 %	65%	70%	80%
> 20-40 %	45%	70%	80%
0-20 %	25%	65%	80%

In comparison to the Colorado rule, the first deadline in the NMED proposal is not until 1 January 2024, eight months (*and an additional ozone season*) after the second deadline under the Colorado rule. In addition, the requirements under the NMED proposal for this later date are weaker in almost every case than the requirements under the Colorado rule. For example,

- The operator with no non-emitting controllers now would have to convert 45% of its controllers by 5/1/23 in Colorado, but only 25% of its controllers in NM by 1/1/24.
- The operator with 15% non-emitting controllers today would also have to convert an additional 45% of its controllers in Colorado by 5/1/23, but only an additional 10% of its controllers in NM by 1/1/24.
- Similarly, the operator with 18% non-emitting controllers now would have to convert an additional 42% of its controllers by 5/1/23 in Colorado, but only an additional 7% of its controllers in NM by 1/1/24.
- Finally, the operator with 25% non-emitting controllers now would have to convert an additional 40% of its controllers by 5/1/23 in Colorado, but only an additional 20% of its controllers in NM by 1/1/24.

Clearly, the NMED proposal is much weaker for the initial years, and would only require operators to catch up to Colorado's 2023 requirements at the beginning of 2027! Each additional year of delay means thousands of additional tons of VOCs and tens of thousands of additional tons of methane will be emitted. Those environmental and public health impacts are irreversible.

Above, we discussed the benefits of using the Colorado approach of requiring operators to achieve a fixed *increase* in the percentage of non-emitting controllers, rather than requiring operators to achieve a specific percentage of non-emitting controllers, and we have proposed that

New Mexico adopt this approach. However, it is important to note that under the NMED proposal, even the operators at the bottom of a cohort *who therefore need to do the most under that proposal's structure* have to do significantly less by January 1, 2024 than they would have to do under Colorado's proposal by May 1, 2023. For example,

- As mentioned above, the operator without any non-emitting controllers now would have to convert 45% of its controllers by 5/1/23 in Colorado, but only 25% of its controllers in NM by 1/1/24.
- An operator with just over 20% of non-emitting controllers now would have to convert an additional 40% of its controllers by 5/1/23 in Colorado, but only about 25% of its controllers in NM by 1/1/24.
- An operator with just over 40% of non-emitting controllers now would have to convert an additional 35% of its controllers by 5/1/23 in Colorado, but only about 25% of its controllers in NM by 1/1/24.

Again, these are the operators required to do the most under NMED's proposal, but they have to do significantly less, by a later date, than they would be required to do in Colorado.

Given these shortcomings in the NMED proposal, we have proposed changes to the pneumatics retrofit provisions that would:

- Adopt the Colorado structure, which requires operators to achieve a fixed increase in the percentage of non-emitting controllers, rather than requiring operators to achieve a specific percentage of non-emitting controllers.
- Move the first deadline to May 1, 2023, which is also consistent with Colorado's rules.
- Strengthen the required conversion percentages for the first deadline, to requirements that are in line with those from Colorado for well production facilities for May 1, 2023.

After 2024, the NMED proposal would require operators to achieve further conversions of emitting pneumatic controllers by January 1, 2027, and January 1, 2030. Given the feasibility of the alternative technologies we have described here, these long timeframes are inappropriate.

As such, we propose a second deadline of May 1, 2025, by which date operators would need to convert a significant portion of their remaining controllers.

Q: Did NMED estimate the costs of retrofitting pneumatic controllers?

A: Yes, NMED prepared cost estimates for the pneumatic controller retrofit provisions, which I am copying here:

Segment	# of Sites	Sum of Emissions After NSPS Regulations (tpy VOC)	Annual costs of NMED Rule	Emissions after NMED Rule control changes	tpy VOC Reductions	Cost per ton VOC Reduced
Gathering and Boosting	915	3,899	$3,001,042	2,743	1,156	$ $2,596
Natural Gas Processing	48	-	$-	-		
Transmission Compressor Station	68	77	$386,682	-	77	$5,023
Wellhead/Tank Battery	47,937	30,631	$82,650,426	517	30,114	$2,745
Grand Total		34,607	$86,038,149	3,260	31,347	$2,745

Q: Are NMED's cost estimates reasonable?

A: NMED's estimates generally are reasonable, but we note that they have overestimated the net costs of pneumatic controller retrofits for several reasons.

First, NMED's estimates omit the increased revenues that operators receive because, after retrofitting facilities to eliminate venting pneumatic controllers, they are able to sell the gas that the pneumatic controllers would otherwise vent.

Second, NMED's estimates omit the maintenance savings that operators realize when they convert from gas-driven controllers to instrument air or electric controllers. The natural gas used to operate pneumatic controllers at production sites and natural gas processing plants has constituents that can interfere with the performance of the controllers in two ways. First, some constituents can condense in the controllers, forming droplets of liquid that can interfere with the operation of the controller.[24] Second, some constituents can be chemically incompatible with seals and other components of the controller.[25] Operators have reported significant cost savings after converting to instrument air and electric systems, as these problems are entirely avoided.[26]

Third, NMED estimates the costs for retrofitting all sites with access to electricity by modeling costs for instrument air systems. For smaller sites, electric controllers will often be more cost effective.[27]

Fourth, NMED estimates costs by estimating costs for each device type (P. Control – Low; P. Control – Int.; P. Control – High; and Pump), at each site type (Wellhead/Tank Battery; Gathering and Boosting; Natural Gas Processing; and Transmission Compression Station). In order to achieve the standard, the model turns controls on or off for specific device type/site type combinations.[28] That is, the model is calculating costs and benefits for partial retrofits of sites. However, it is more cost effective to retrofit all devices at a site, since non-emitting controllers utilize common equipment at pads, such as air compressors and tanks for instrument air systems, and solar panels, batteries, and control panels for electric controllers.[29] Therefore, operators will replace all controllers and pumps at a given site, which is a more cost-effective approach. If costs

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[24] See Carbon Limits (2016) at 18, 26 [Clean Air Advocates' Ex. 4].
[25] See *City of Fort Worth Natural Gas Air Quality Study* at 3-100.
[26] See Carbon Limits (2016) at 18, 26.
[27] See *id.* at 23.
[28] See "Read Me" tab: "The choices made in Columns S and W are targeting an implementation/installation of 85% non-emitting controllers for wellheads, tank batteries, and gathering boosting stations, based on the requirements in Table 1 of 20.2.50.122 NMAC. The choices made in Columns S and W are targeting an implementation/installation of 98% non-emitting controllers for gas processing plants and compression stations based on Table 2 of 20.2.50.122 NMAC."
[29] See Carbon Limits (2016) [Clean Air Advocates' Ex. 4].

were to be estimated on a site-basis, rather than component by component, the cost estimate would be lower.

Q: How would the changes that the Climate Advocates propose for the pneumatic controller retrofit provisions change the costs of the program?

A: The changes that we propose for the pneumatic controller retrofit provisions simply accelerate the transition already required by NMED's proposal. The required pace of retrofits under the program would still be very reasonable and similar to that required in Colorado. This accelerated schedule would therefore not increase overall costs in any significant way; at most, it would require owners and operators to incur some of these costs sooner than they otherwise might (while also increasing cumulative environmental benefits and ensuring that these benefits accrue sooner). Therefore, the changes we propose would not materially change the overall cost effectiveness of the program.

Q: Why do Clean Air Advocates recommend deletion of the provision that would exempt an operator from performing any additional retrofits if at least 75% of the operator's pneumatic devices are non-emitting by 2025?

A: Proposed 20.2.50.122.B(4)(c)(v) NMAC states: "if an owner or operator meets at least seventy-five percent total non-emitting controllers by January 1, 2025, the owner or operator has satisfied the requirements of table 1 and 2". This provision should be deleted, for several reasons.

First, the provision creates internal inconsistency in the rule text. The first row of Table 1 provides that an operator with a total historic percentage of non-emitting controllers of 75% or greater must achieve 80% by 2024, 85% by 2027, and 90% by 2030. The first row of Table 2 likewise sets forth targets for operators with a total historic percentage of non-emitting controllers of 75% or greater. Yet the proposed 20.2.50.122.B(4)(c)(v) NMAC states that operators don't have to perform any more retrofits if they reach 75% before 2025. This is tantamount to striking the first row of Table 1 and Table 2. It is unclear to us if NMED intended to do that, or if 20.2.50.122.B(4)(c)(v) NMAC is a vestige of a prior draft that should have been deleted.

Second, this provision makes the rule less effective, because it could result in a large number of pneumatic devices not being converted, even where it would be technically feasible and cost-effective to do so.

Third, NMED has not set forth any technical or economic basis for this exemption. NMED's analysis shows that is technically feasible to retrofit emitting controllers with zero-emission controllers and that the cost per ton of VOCs abated is reasonable. The incremental benefits of an additional retrofit are the same regardless of what the operator's historic percentage is.

While NMED may be interested in this provision as a way to encourage some operators to more rapidly a large portion their existing controllers so that they can exploit this provision, such an incentive approach is not needed. As discussed throughout my testimony, these retrofits are cost-effective and feasible. The proper approach is for the retrofit program to be accelerated so that all operators diligently work to eliminate this harmful and wasteful source of emissions, rather than allowing some operators to continue operating a significant portion of their gas-driven controllers indefinitely as an incentive for them to speed up out these straightforward, low-cost retrofits.

STORAGE VESSEL MEASURING SYSTEMS

Q: What changes are Clean Air Advocates proposing to the section of the proposed rule regulating storage vessels?

A: Clean Air Advocates propose to add a new subsection C to 20.2.50.123 NMAC, entitled "Storage Vessel Measurement Requirements." This provision mirrors almost word for word an amendment to Regulation 7 adopted by the Colorado Air Quality Control Commission (AQCC) in December 2019. That amendment appears at 5 Colo. Code Regs. § 1001-9:D.II.C.4.

Q: What is the purpose of this new subsection?

The new subsection would reduce emissions from storage vessels installed at new or modified facilities by requiring those tanks to employ a "storage vessel measurement system" to determine the quantity and quality of liquids inside a storage vessel. Typically, in order to measure the level of liquid in a tank, operators open a thief hatch on the top of the tank in order to insert a gauging device. Operators also typically collect samples of the liquid in the vessel through the hatch. When the hatch is opened, air pollutants, including methane, VOCs, and cancer-causing HAPs like benzene, are released. Since gauging is often performed frequently, and the hatch is opened every time a measurement is taken, these emissions can be significant.

Operators can avoid these emissions by employing an alternative system to measure and sample the liquids in the vessel. Examples of alternative systems that do not require venting include systems that comply with Chapter 18.2 of American Petroleum Institute (API)'s Manual of Petroleum Measurement Standards, or by installing a Lease Automatic Custody Transfer (LACT) unit. In 2019, the Colorado AQCC required operators to employ these types of alternative systems for new or modified storage vessels. Clean Air Advocate's proposal would impose the same requirements in New Mexico.

Q: What are the benefits of Clean Air Advocates' storage vessel measurement proposal?

A: Clean Air Advocates' proposal reduces emissions, using systems that have been used for years in the field, at a reasonable cost to industry. It also has important safety benefits, which I will discuss.

The Colorado Air Pollution Control Division (APCD) included an analysis of its storage vessel measurement system regulation in its December 5, 2019 Regulatory Analysis for Regulation Number 7 Revisions. Using cost data from a leading manufacturer of equipment used to facilitate the use of API Method 18.2, this analysis showed that use of a storage vessel measurement system is generally cost-effective, with cost-effectiveness increasing the more often measurement (which is carried out each time liquid is transferred from the tank to a truck, a process referred to as "loadout") occurs.

Loadout frequency	**Cost per ton VOC**	**TPY VOC reduced (per 8-tank battery)**
100 loads per year	$3,447/ton VOC	5.1
365 loads per year	$944/ton VOC	18.6

See December 5, 2019, Regulatory Analysis for Regulation 7 Revisions at 19.[30]

The Colorado APCD stated that these numbers were "extremely conservative, insofar as the new and modified facilities that will be subject to these requirements will likely have production at such a level where loadout happens more often than even one time per day." *Id.* In addition, the APCD found that equipment costs would be lower for owners and operators who used storage vessel measurement systems at multiple facilities, and that the use of a storage

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30 https://www.edf.org/sites/default/files/content/Attachment%20B%20-%20Regulatory%20Analysis%2C%20Colorado%20Dep%E2%80%99t%20of%20Public%20Health%20and%20the%20Environment%20%28Dec.%205%2C%202019%29.pdf.

vessel measurement system would provide a benefit to owners and operators by increasing the accuracy of the measurement, something that would payback over time. *Id.* at 20.

Q: Will Clean Air Advocates' proposal have safety co-benefits?

A: Yes. The National Institute of Occupational Safety and Health and the Occupational Safety and Health Administration issued a Hazard Alert in February 2016, explaining that the agencies had "identified health and safety risks to workers who manually gauge or sample fluids on production and flowback tanks from exposure to hydrocarbon gases and vapors, exposure to oxygen-deficient atmospheres, and the potential for fires and explosions." NIOSH/OSHA Hazard Alert: Health and Safety Risks for Workers Involved in Manual Tank Gauging and Sampling at Oil and Gas Extraction Sites, at 1.[31] The Hazard Alert explained that "[o]pening tank hatches, often referred to as 'thief hatches,' can result in the release of high concentrations of hydrocarbon gases and vapors" which "can have immediate health effects, including loss of consciousness and death." *Id.* It went on to survey nine cases between 2010 and 2014 where a worker died while performing manual tank gauging. *Id.* at 11. The agencies recommended use of "alternative tank gauging and sampling procedures that enable workers to monitor tank fluid levels and take samples without operating the tank hatch" to reduce occupational hazards associated with manual gauging. *Id.* at 6. Clean Air Advocates' proposal would require exactly that at new and modified facilities, creating an important co-benefit in terms of occupational safety at the same time as it reduces emissions of ozone-forming VOCs and other dangerous pollutants.

This concludes my testimony, which is accurate to the best of my knowledge.

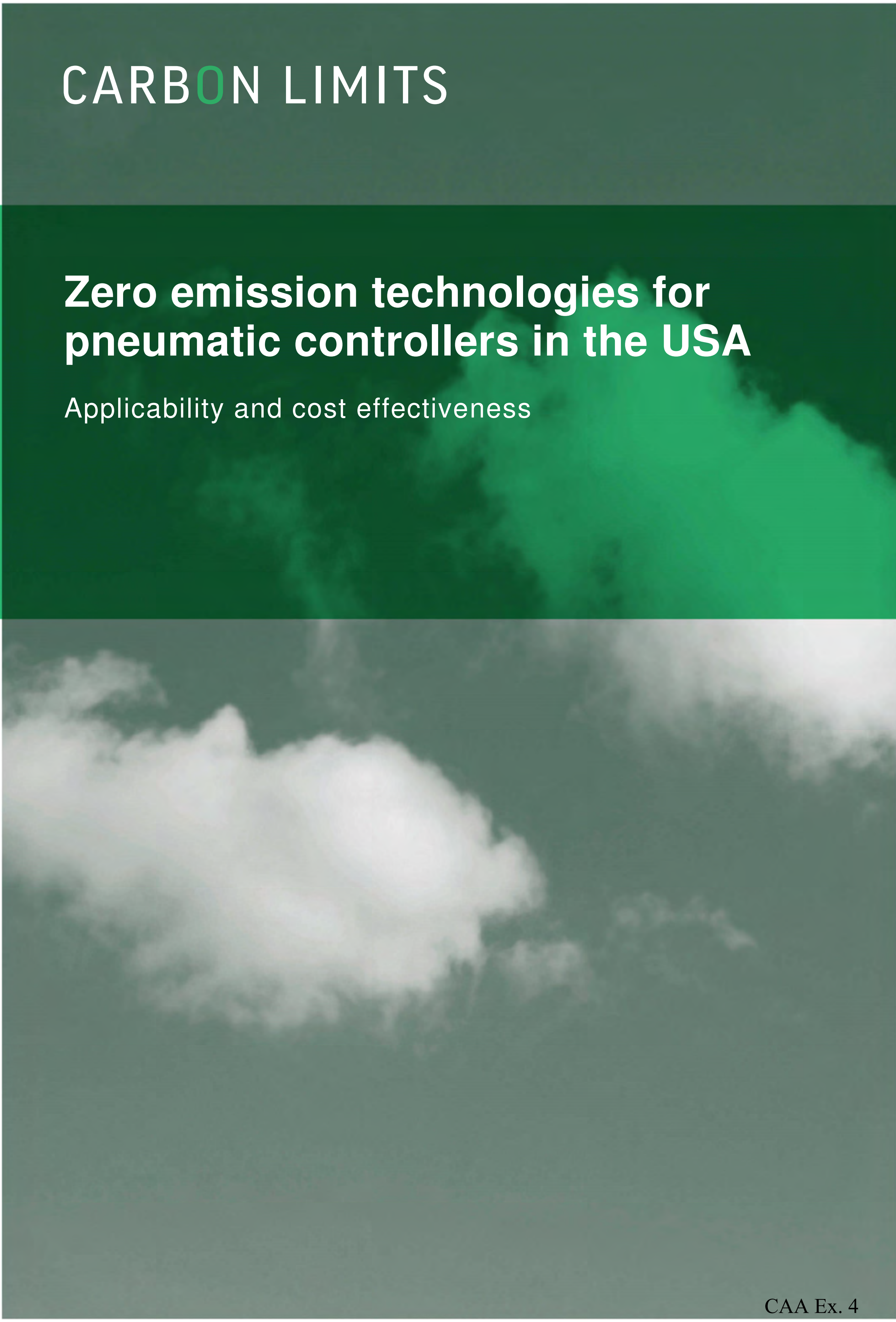
/s/ David McCabe July 28, 2021

[31] https://www.osha.gov/sites/default/files/publications/OSHA3843.pdf.

David McCabe, Ph.D. Date

CLEAN AIR ADVOCATES' EXHIBIT 4

CARBON LIMITS



Zero emission technologies for pneumatic controllers in the USA

Applicability and cost effectiveness

CAA Ex. 4

CARBON LIMITS

This report was prepared by Carbon Limits AS.

Project title:
Zero emission technologies for pneumatic controllers in the USA

Client:	CATF
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Carbon Limits is a consulting company with long standing experience in supporting energy efficiency measures in the petroleum industry. In particular, our team works in close collaboration with industries, government, and public bodies to identify and address inefficiencies in the use of natural gas and through this to achieve reductions in greenhouse gas emissions and other air pollutants.

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Executive Summary

Natural gas-driven pneumatic controllers are used widely in the oil and natural gas industry to control liquid level, temperature, and pressure during the production, processing, transmission, and storage of natural gas and petroleum products. However, these devices release methane into the atmosphere. Pneumatic controllers are the second-largest source of methane from the US oil and gas industry, behind only component leaks, according to US EPA's Greenhouse Gas Inventory.

US Federal rules require that new continuous-bleed controllers be *low-bleed* (defined as designed to emit less than six standard cubic feet/hour) at production sites and compressor stations and be *zero-bleed* at processing plants. Unfortunately, recent measurements have demonstrated that many controllers currently in field use are emitting more than would be expected based on design specifications.

This study was undertaken to determine whether cost-effective non-emitting technologies are available to eliminate this major emissions source. We find that these technologies have evolved considerably over the past decade and are now available and actively in use in oil and gas fields in the United States and Canada. Two technologies are mature, proven, and in relatively wide use, and as we discuss in this report, these technologies provide a cost-effective way to eliminate emissions of methane and other pollutants from pneumatic controllers.

Major findings include:

- Zero emission technologies can virtually eliminate emissions from pneumatic devices.
- A number of technologies are available. The two most promising, which this report focuses on, are electronic controllers – both solar and grid powered – and instrument air**.**

  Electronic controllers can be installed both at sites connected to the electric grid and at sites isolated from the grid.

  Instrument air technology is a well-established, mature solution to run pneumatic control systems and is widely applied globally. The technology requires a reliable power supply, either from the grid or from generators on the site.
- Currently, electronic controllers are generally used at smaller sites while instrument air is used at larger sites, due to the technical limitations of air compressors. These two technologies are on the market today, from multiple suppliers.
- Due to the market conditions, providers of electronic controllers have so far focused mainly on the development of solutions for small sites in remote locations. There thus seems to be much less field experience with using electronic controllers at medium and large sites; however, no technical barriers were identified for this type of installation.
- A number of other zero emission solutions are available today with more limited applicability (e.g. self-contained devices) or fewer documented implementations (e.g. solar-powered instrument air). Depending on the site specificities, these options can represent useful alternatives to instrument air or electronic controllers.
- Operators have successfully installed hundreds of systems. They report positive experiences on both new and retrofit sites, valuing zero emission solutions for their low maintenance costs and reliability.
- An economic analysis, assuming conservative average emission factors for pneumatic controllers, was performed for 2032 site configurations with 1 to 40 controllers (excluding emergency

shutdown devices). Both retrofit and new installations, with and without electricity on-site, were considered.

- Zero emission solutions have abatement costs below the social cost of methane used by US EPA ($1354/t$CH_4$, mean value calculated for 2020 with a 3% discount rate in 2016 USD) in the vast majority of the site configurations considered (2008 out of 2032 site configurations).
- The abatement costs, calculated as described above, exceed the social cost of methane used by US EPA primarily at very small sites – those with less than three controllers (excluding emergency shutdown devices). However, if higher emission factors, as reported from recent field measurements, are used, the abatement costs at even the very small sites will fall below the social cost of methane.

Overall, we find that zero emission solutions are available today and are cost effective to implement in nearly every situation.

The following table presents a summary of both the technical applicability and economic attractiveness of the different zero emission technologies under different categories of sites. Though this analysis does not provide a detailed evaluation of the distribution of the sites in the US for each of the below categories, existing studies have suggested that the vast majority of the sites have less than 20 controllers.

			Both retrofit and new sites					
Type of of site		**Number of controllers** (excl. ESDs)	**1- 3**		**4-20**		**21-40**	
		Electricity on-site?	Yes	No	Yes	No	Yes	No
Main options: Electric controller Instrument air		**Description** (of the most economic option which is technically feasible)	Grid connected **electric** controller	Solar powered **electric** controller	Grid connected **electric** controller	Solar powered **electric** controller	Instrument **air**	
		Number of cases not cost effective (i.e. abatement cost > social cost of methane) **under central assumptions**	6 / 36	11 / 36	0 / 308	2 / 308	5/ 328	
		Cost effective for <u>every</u> site configuration if emissions factors are:*	> 5.6 scfh for retrofit > 2.8 scfh for new sites	> 7.2 scfh for retrofit > 4.4 scfh for new sites	> 3.6 scfh for retrofit > 1.4 scfh for new sites	> 4.2 scfh for retrofit > 1.8 scfh for new sites	> 4.5 scfh for retrofit > 1.8 scfh for new sites	
Other options potentially applicable depending on the local conditions	**Limited applicability**	Vent gas recovery	✓	✓	✓	✓	✓	✓
		Instrument air powered by gas	Not relevant	Not relevant	Not relevant	Not relevant	Not relevant	✓
		Self contained controllers	✓	✓	✓	✓	✓	✓
	Limited known implementations	Solar powered instrument air	Not relevant	✓	Not relevant	✓	✗	✗
		Electric controllers powered by other power sources (TEG, fuel cell)	Not relevant	Not relevant	Not relevant	Not relevant	Not relevant	✓
		Large solar powered electric controller (no known implementations)	Not relevant	Not relevant	Not relevant	Not relevant	Not relevant	Potential solution,** but no example known.

*Emissions factors threshold listed are determined for the site configuration with the highest abatement cost within the category.
** Based on other solar applications. No fundamental barrier identified.

Abbreviations and Notes on Units

CAPEX	Capital Expenditure
CH_4	Methane
CO_2eq	Carbon dioxide equivalent
EF	Emission Factor
ESD	Emergency shut down
GHGRP	Greenhouse Gas Reporting Program – US EPA
GOR	Gas/oil ratio
Mscf	Thousands standard cubic feet
MMscf	Million standard cubic feet
MMscfd	Million standard cubic feet per day
MMT	Million tons
OPEX	Operational expenditure
SCADA	Supervisory Control and Data Acquisition
Scfh	Standard cubic feet/hour
USD	US dollars
VOC	Volatile Organic compound
VRU	Vapor Recovery Unit

Notes on units:

All the data are presented in metric tons

All monetary figures are presented in US dollars, denoted as $

Social Cost of Methane: This report uses the social cost of methane, as reported by US EPA in recent regulatory analyses, as a benchmark for the cost-effectiveness of measures to abate methane emissions. We use the mean value calculated at the 3% discount rate for emissions in year 2020. EPA calculates this as $1300 per metric ton in 2012 USD. We have converted this to $1354 per metric ton in 2016 USD, using a cumulative rate of inflation of 4.2%.

1. Introduction

1.1 What is the problem?

Natural gas-driven pneumatic controllers are used widely in the oil and natural gas industry to control liquid level, temperature, and pressure during the production, processing, transmission, and storage of natural gas and petroleum products. However, these devices vent methane into the atmosphere. Pneumatic controllers are the second-largest source of methane from the US oil and gas industry, behind only component leaks, according to US EPA's Greenhouse Gas Inventory [1].

Over the last few years, regulators have worked to reduce the emission of methane and volatile organic compounds (VOCs) from pneumatic controllers. US Federal rules require that new continuous-bleed controllers be *low-bleed* (defined as designed to emit less than 6 scfh) at production sites and compressor stations and *zero-bleed* at processing plants. Wyoming goes further to include intermittent-vent controllers in its requirement that *all* new controllers are designed to emit less than 6 scfh. It also requires the replacement of existing high-emitting controllers in some areas and caps allowable emissions in other areas. Recently Colorado required that existing high-continuous-bleed controllers be replaced with low-bleed controllers statewide, and other states are currently considering similar measures. Finally, some operators have reported voluntary replacements of high-bleed controllers with low-bleed controllers to programs such as US EPA's Natural Gas STAR.

Unfortunately, recent measurement studies [2,3,4] have reported higher emissions from low-bleed controllers than expected. Some controllers that are considered low-bleed according to manufacturer specifications actually bleed above the low-bleed threshold of 6 scfh. Indeed, a number of controllers appear to malfunction, emitting significantly more than they are designed to emit.

Moreover, as a class, intermittent-vent controllers, which are largely unregulated, far outnumber continuous-bleed controllers, and EPA estimates that emissions from intermittent-vent controllers are considerably higher than emissions from continuous-bleed controllers [1]. Recent work has demonstrated that some controllers designed to emit intermittently fail and begin leaking natural gas continually [2,5].

Given the wide range of applications of pneumatic controllers, their typical installation in remote, unmanned sites, and the limited resources of air quality regulators, it is very challenging for air quality regulators to ensure compliance to emissions standards for pneumatic controllers. Currently, new continuous-bleed controllers are in compliance with EPA rules, if they are designed to emit below the EPA threshold of six cubic feet per hour. In practice, they may emit more depending on installation parameters (such as the pressure of the supply-gas), malfunctions, or even tampering, e.g. production workers modify controllers bleed rates when they believe that it will improve reliability [9]. Finally, it is inherently difficult to quantify the emissions from intermittent-vent controllers, as their actuation frequency is variable and may change over time.

1.2 Objective of this project

Zero emission technologies have the potential to virtually eliminate this emission source. They have evolved extensively over the last few years, as operators have gained experience using them. Yet, although zero emission technologies are often mentioned in best practices documentation and reports, there is very limited information on overall applicability and costs (with the exception of instrument air).

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This report documents how zero emission technologies are being used in gas and oil fields, and discusses the zero emissions technologies that are suitable for wide usage in common applications at oil and gas production facilities and compressor stations. The main objectives include:

- Presentation of zero emission technologies that are currently available on the market.
- Discussion of the applicability and the technical barriers to the implementation of these technologies.
- Estimates of implementation and methane abatement costs of these technologies for new installations and retrofits.

1.3 Approach and methodology

In addition to a comprehensive literature review, this report relies on interviews with a number of relevant stakeholders and a detailed cost-benefit analysis.

Interviews: Seventeen interviews were conducted. Nine were with technology providers, and eight with both small and large oil and gas companies. The interviews gathered information on field experience with the implementation of zero emission technologies, in particular on their applicability, technical barriers experienced, and actual costs and benefits.

Cost-benefit analysis of zero emission technology implementation: Based on the information gathered during the interviews, literature reviews, and online equipment quotes, a cost-benefit analysis was performed covering a wide range of possible site configurations.

The cost-benefit analysis is presented in section 4 of this report. Prior to that, section 2 includes an introduction to controller typologies, followed by a brief literature review of emissions from controllers. Section 3 presents the different zero emission controller technologies and includes a description of field experiences with these technologies. The report concludes with a brief overview of existing applicability and costs under a range of circumstances.

2. Gas Driven Pneumatic controllers – What are we talking about?

2.1 Definition

A process controller is a device that senses a physical state and then operates automatically to regulate that state[1], based on an established set-point in its control logic. Process controllers can regulate a variety of physical parameters – or *process variables* – including fluid pressure, liquid level, fluid temperature, and differential pressure. An example of a common type is a separator dump valve controller, which operates when it senses that liquid has reached a certain level. Process controllers can be electric, hydraulic, pneumatic or a combination of them. An example of a combination controller would be an electrohydraulic controller operating an electric valve to send liquid pressure to a hydraulic end-device.

Pneumatic controllers convert an input signal to a pneumatic pressure output using gas pressure. The end-device, i.e. the control valve, is adjusted by the actuator in response to signal from the controller.
A pneumatic controller uses gas pressure to open or close a mechanical device, such as a valve, when it senses the need to regulate a process condition such as liquid level, pressure, temperature, or flow.

[1] In complex control systems, other process control variables might be modulated to regulate the *state* of that process variable.

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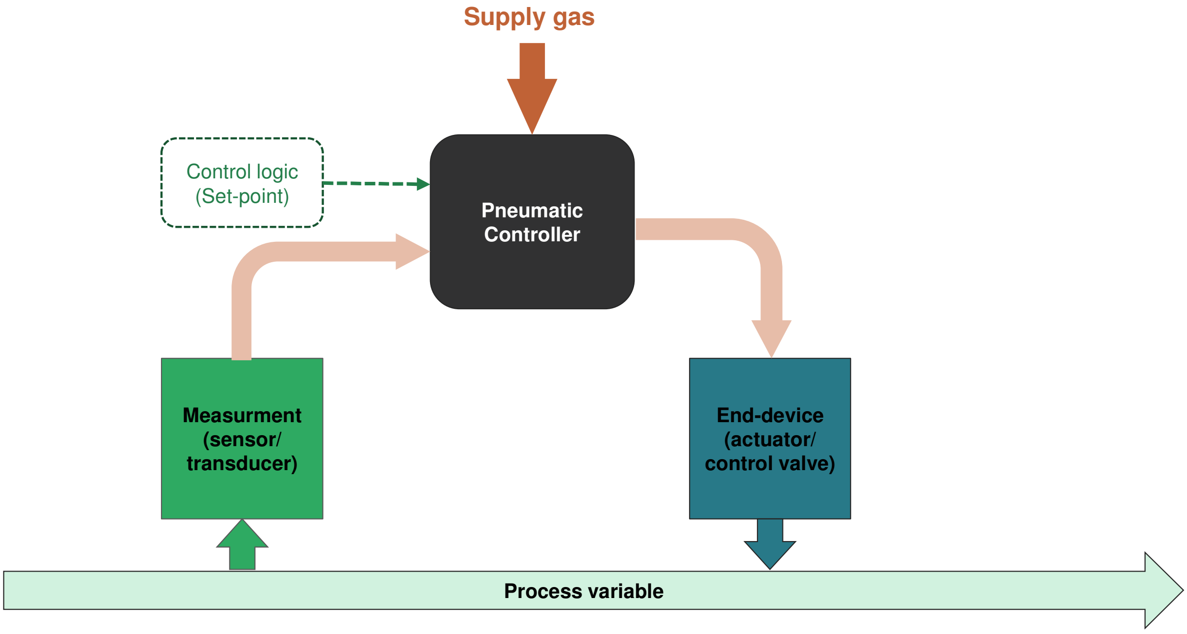
Figure 1: Pneumatic Controller - concept sketch



2.2 Typology of controllers

Different typologies have been used in the literature to classify controllers, based on:

- The controller application (i.e. what the controller is used for, such as to control liquid level, pressure, or temperature)
- The emission pattern of the controller (continuous-bleed or intermittent vent)
- The end service (i.e. the way the controller regulate the parameter, such as *on/off* service or *throttle* service)

Controller application
Pneumatic controllers are widely used in upstream oil and gas operations, most commonly to regulate fluid level in separators and tanks, temperature of heaters and fans, pressure of vessels, and differential pressure of lines.

Emission pattern of the controllers
Pneumatic controllers can be designed to release supply-gas continuously or intermittently. Pneumatic controllers are thus classified as **continuous-bleed** or **intermittent-vent** (equivalent to intermittent bleed in all EPA documents), depending on whether or not they are *designed* to emit continuously.

In this study,

- emissions occurring from intermittent-vent controllers, where there is a physical barrier between the supply-gas and the end-device, are referred to as ***vent***; and
- emissions from continuous-bleed controllers, where the supply-gas provides required pressure to the end-device while the excess amount of gas is emitted, are referred to as ***bleed***.

The continuous-bleed controllers are classified into high-bleed and low-bleed in this report, depending on whether or not the controller is deemed to have a bleed rate above or below 6 scfh, in line with EPA regulations.[2]

The typology used in this report differs from the one presented in Allen et al. [2] where controllers are classified depending on their measured emissions pattern as opposed to their designed emissions pattern.

End-service typology

The end-device can be in *on/off* service or *throttle* service, depending on the process requirements. An example of on/off service is a dump-valve that controls the level of a vessel. In the "on" state, the valve is completely open to "dump" liquid. When the desired level has been achieved, the valve completely closes to its "off" state. An example of throttle service is a pressure control valve, which increases or decreases the flow of gas as needed to maintain line pressure at a fixed value. Both continuous-bleed and intermittent-vent controllers are commonly used to perform both on/off and throttling services.

A summary of pneumatic controller typology is presented in the table below. As this study focuses on eliminating emissions from these devices, only the emission pattern typology is used in the rest of the report.

Table 1: Summary of controller typology (mainly based on [6])

		Type of Service	
		On/Off	**Throttling**
Emission characteristics	**Intermittent-vent**	- Gas vented at de-actuation - Designed to emit no gas between de-actuation instances - De-actuation frequency depends on process variability	- Gas vented when end-device needs to throttle-off - Designed to emit no gas between throttle-off instances - Throttling frequency depends on process fluctuations
	High-bleed continuous controller	- Gas emitted continuously with higher bleed rates when end-device needs "off" service - Nevertheless, the average bleed amount is constant - Bleed rates are by definition deemed to be higher than 6 scfh	- Gas emitted continuously with higher bleed rates end-device needs to throttle-off - Nevertheless, the average bleed amount is constant - Bleed rates are by definition deemed to be higher than 6 scfh
	Low-bleed continuous controller	- Gas emitted continuously with higher bleed rates when end-device needs "off" service - Nevertheless, the average bleed amount is constant - Bleed rates are by definition deemed to be lower than 6 scfh	- Gas emitted continuously with higher bleed rates end-device needs to throttle-off - Nevertheless, the average bleed amount is constant - Bleed rates are by definition deemed to be lower than 6 scfh

2.3 Number of controllers and emission factors – Brief literature review.

Important work has been taking place over the last few years to measure and understand methane and VOC emissions from pneumatic controllers. This work includes measurement surveys [2,3,4,7], count of controllers per facility [1,2,8], and engineering calculations [8]. The methodology and the sampling approach vary significantly between different sources of information; thus comparisons should be made with particular care [8].

[2] It should be noted that the bleed rate is not a specification of the controller only, but also depends on the pressure and flow-rate of the supply-gas in addition to the size of the restriction orifice.

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How many controllers per site?
The number of controllers per site varies depending on the number of wells and more generally the number and type of equipment used. Recent studies have demonstrated that the vast majority of sites have less than 20 controllers.

Most of the existing studies have focused only on emitting controllers [3,5,7], thus underestimating the number of controllers reported for each site, since some intermittent-bleed controllers actuate infrequently (e.g., controllers for emergency shut-down valves) and are unlikely to do so while a site is being surveyed. Two studies have performed a thorough count of the number of controllers per site [2,8]. The distribution of controller functions reported by these studies varied, perhaps due to differences in the types of sites sampled in the studies, but the overall distribution of controller counts at production sites were quite similar (Figures 2 and 3):

- Very small and medium sites (with less than 20 controllers) account for the vast majority (97%) of the sites evaluated in both studies (Figure 2)
- These sites represent 85% of the controllers (Figure 3)

Figure 2: Share of the sites depending on the total number of controllers per site

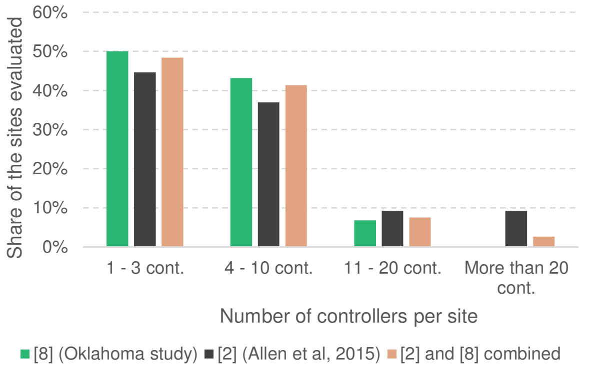
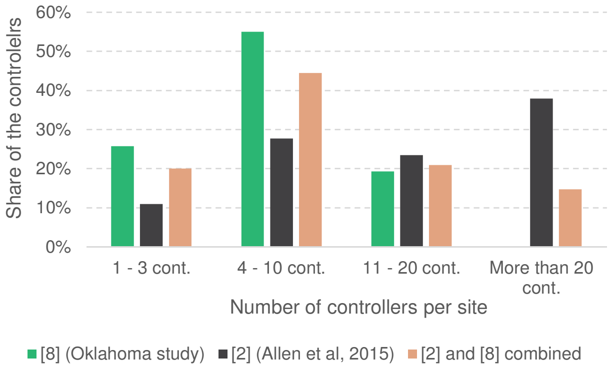


Figure 3: Share of the controllers depending on the total number of controllers per site



How much do controllers emit?
Despite the important work performed over the last few years, there is still significant uncertainty regarding emissions factors from controllers. The following figure summarizes the current emission estimates available for the different categories of controllers.

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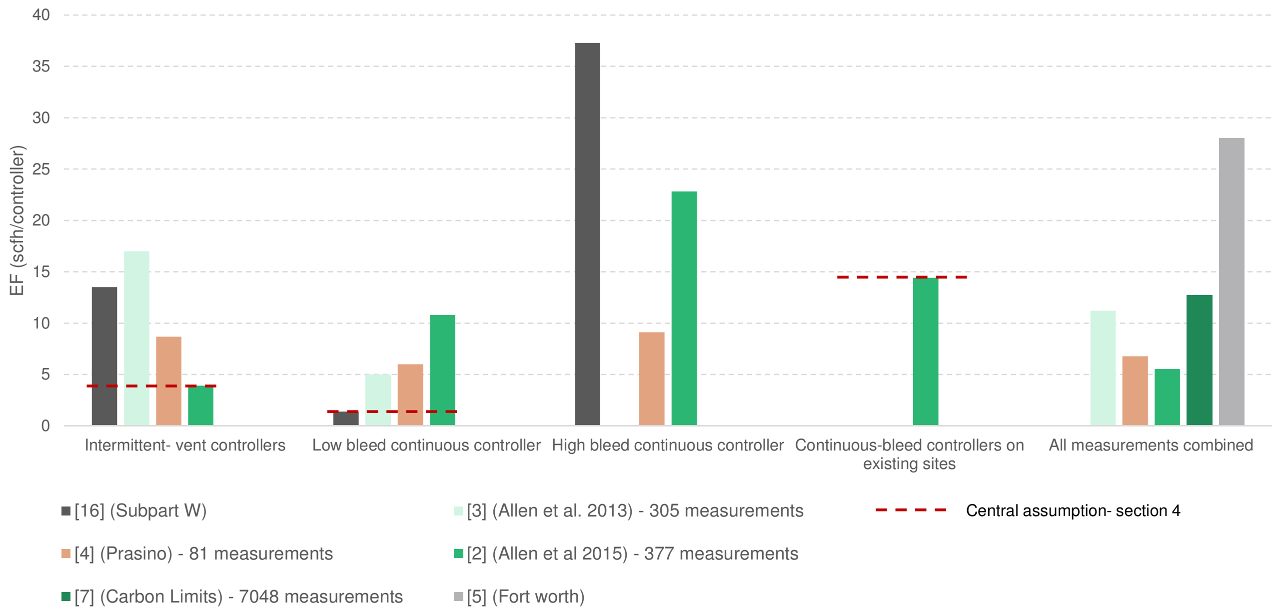
Figure 4: Emissions factors by controller category from different information sources[3]



A number of important conclusions can be drawn from the review of existing publications:

- Emissions from controllers vary between controller models and, for some models, for the same controller model between sites [2,4,7]
- A small subset of the controllers account for the vast majority of the emissions [2,7]
- Overall, recent research has demonstrated that a number of controllers behave differently than originally designed. In particular,
    - Average emission rates exceed the manufacturers' specifications [4], including some controllers designated low-bleed which emit above the threshold rate of 6 scfh [4,7]
    - Some controllers designed to emit intermittently fail and begin emitting natural gas continually [2,5]

In the analysis presented in the report, we have very conservatively adopted the lowest of the above average EFs for low-bleed in new installations and for intermittent-vent controllers. For continuous bleed controllers at existing sites, we have used the results of the recent measurement [2]. This average is consistent with a mix of low- and high-bleed in the field. The EFs are illustrated in Figure 4 and are described further in Section 4.1.

Do controllers from smaller sites emit more?

There is very little information available on how emission factors vary depending on the site's size. Analysis of recent measurements [2] suggests, however, that controllers are likely to emit much more in small than in large sites.

The following graph, plotting the mean and the eightieth percentile emission factors, shows a clear downward trend as the number of controllers per site increases. This trend could potentially be explained by the difference in terms of maintenance practices for small sites (typically unmanned and in remote area) and larger sites. In the follow-up analysis, a constant emission factor is assumed for both small and large sites.

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[3] The data from [3] and [4] have been categorized and presented as described in [8]. The data from [2] have been categorized based on the "company classification into EPA category" (excluding ESD) and not based on the measured emission typology.

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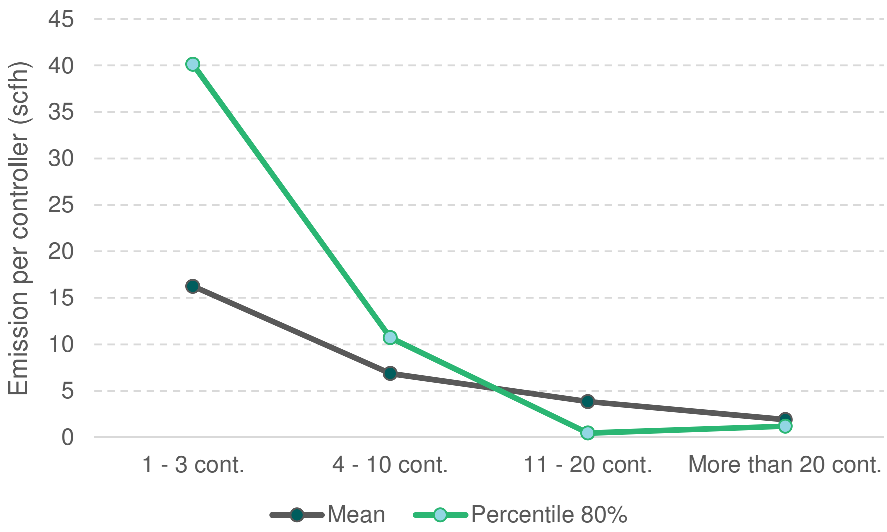
Figure 5: Average emission factors depending on the number of controllers per site [2]



3. Zero emission technologies – Description and technical applicability

This section provides an overview of a number of zero emission technologies available as an alternative to gas driven pneumatic controllers, based primarily on interviews and on a general literature review. A technology is considered "zero emission" if there is no methane or VOC emissions associated with its utilization.

3.1 Overview of the zero emission technology presented.

Five different technologies have been reviewed: Electronic controllers, instrument air provided by compressors (with electric power from the grid or existing on-site generation), solar-powered instrument air, vent recovery, and self-contained pneumatic controllers. Of these five different zero emission technologies, two – electronic controllers and instrument air – have reached a reliable level of maturity and are widely applicable. The remaining three technologies are either less mature (solar-powered instrument) or are applicable only in certain circumstances (self-contained pneumatic controllers and vent recovery).

The economic feasibility of the two mature and widely applicable technologies, electronic controllers and instrument air, is evaluated in detail in section 4 of this report.

The following table presents a brief summary of the different technologies evaluated.

Table 2: overview of the zero emission technologies presented

Technology	Maturity of the technology	Technical applicability limitations	Main strengths
Electronic controllers (ref section 3.2)	The technology has reached a reliable level of maturity, with hundreds of installations identified throughout this study.	Operators interviewed continue to use pneumatic ESDs. Some limitations with large numbers of controllers or high power demand chemical injection pumps.	• Can operate off grid • Reduced maintenance costs, in particular compared to wet gas driven controllers • Enables or simplifies automation of systems

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Instrument air (ref section 3.3)	Extensive global experience for many years	Requires a reliable source of power Limited to installations with an air compressor > 5 HP	• Reliability • Reduced maintenance costs, in particular compared to wet gas driven controllers
Solar-powered Instrument air (ref section 3.4)	Less than 100 installations identified	Compressor up to ~20 scfh	• Operates off grid • Reduced maintenance costs, in particular compared to wet gas driven controllers
Vent Recovery (ref section 3.4)	The study identified less than 100 installations, with uncertain performance	Requires the presence of a VRU or a gas engine on site	• Reliability
Self-contained pneumatic controllers (aka "Bleed to Pressure" or integral controllers) (ref section 3.4)	Although this solution has been deployed since early 2000s and is considered a relatively well-developed technology, controllers of this type are only available for certain specific applications	Applicability is limited by a number of conditions (e.g. pressure differential, downstream pressure, etc.)	• Low-cost solution

3.2 Electronic controllers (solar powered and grid powered)

Electronic controllers adjust the position of the end-device by sending an electric signal to an electric actuator or positioner (as compared to pneumatic controllers which send a pneumatic signal to a pneumatic actuator or positioner). A motor powers the electric actuator to adjust the control valve to the desired position.

This section provides a description of the benefits, costs, and applicability of electronic controllers to both new sites and existing sites, where retrofits would be required. The description is based mainly on interviews with four oil and gas production companies that have installed these systems in their operations (from 3 to 40 installations per operator interviewed), complemented by interviews with technology providers.

Description of the technology
Electronic controllers can be installed both at sites connected to the electric grid, and at remote sites isolated from the grid. These systems typically include a control panel, electric actuators, electronic controllers, control valves, relevant switches (e.g. pressure, level or temperature switch) and a power source – connection to the grid, solar panels and batteries, or power generation on site. An electronic control system is generally designed to completely replace all pneumatically powered devices with electronic controls (with the exception of ESD, see below).

<u>Electrically powered sites</u>: Electronic controllers can be powered using 120 VAC or 220 VAC input from the grid or from on-site generation (three-phase power is not needed).

<u>Remote sites:</u> Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. Systems can be customized for every application; those installed to date include up to three solar panels and eight batteries [9]. Use of solar-powered chemical injection pumps has become widespread over the past years.

Rationale for the use of electronic controllers:
For the operators interviewed, the two main drivers for project implementation were (i) to reduce methane and VOC emissions and conserve gas otherwise emitted and (ii) to reduce maintenance costs. Electronic systems have much lower maintenance costs than traditional gas-driven controller systems [10], in particular if the gas used is not perfectly dry and sweet.

Higher operating costs are also experienced for gas driven controller systems on sites where there is a need to purchase fuel gas from another source or use imported propane. These include sites with overly sour or wet gas, or with drastic drop in gas supply due to low gas/oil ratio (GOR) /low production.

Investment Costs
Each electronic control system is designed on a case-by-case basis. The investment costs depend on the number of controllers/pumps, but also on other factors such as pressure differential, pipeline diameter, and methanol volume requirement, which varies according to such factors as climate and production patterns[4]. The following table summarizes typical equipment costs for the cases evaluated:

Figure 6- Calscan pictures- Bear solar control system: Top: solar panel and control panel, bottom: Electric Actuator

Table 3: Electronic controllers – Typical investment costs for main equipment

Main items	**Approximate unit costs** USD
Level Controller & Level Control Valve	4000
Pressure Controller & Control Valve	4000
Chemical injection Pump	6000
Control panel	4000
Solar panel (140W unit)	500
Battery (100 Ah unit)	500

The operators interviewed experienced fairly smooth installations, with installation costs decreasing as they gained experience with the technology[5]. The installation costs vary by site, estimated at between $5000 and $8000 per well site. For a retrofit project, the well needs to be shut in for one or two days;

[4] Chemical injection pumps (e.g. methanol pumps) usually are the most important power consumer. Sites requiring high volumes of methanol volume injection would cause higher costs for scaled-up solar panel and batteries.
[5] After the first few sites installations.

retrofit will generally take place when other maintenance is scheduled, to take advantage of that shut-down time. Solar powered electric systems do not require back-up generators[6].

Maintenance costs
The major maintenance costs include the replacement of batteries and panels. Most batteries last three to six years, while solar panels last twenty to thirty years. The operators interviewed highlighted that they experienced minimal maintenance costs on the sites converted to electronic controllers over the last five years.

Benefits of electronic controllers
Operators highlighted a number of benefits:

- Revenue from the sale of gas: Electronic controllers eliminate methane and VOC emissions and thus increase the volume of gas available for sale.
- Automation: Electronic control systems can provide additional benefits by enabling or simplifying the installation of automation systems (SCADA, Supervisory Control and Data Acquisition), though these systems are not required in order to use electronic controllers. This can potentially reduce the need for site inspections, reducing those costs for operators. For example, an alarm can be programmed to warn the operator if the dump has been open for more than 10 min. The system can be as sophisticated or as simple as required. (Note that we have not included any estimate of these cost reductions in the calculations of cost-effectiveness discussed in Section 4.)
- Reliability: As highlighted above, operators report that the electronic system is more reliable than a gas driven pneumatic control system, as operation of the latter with even slightly wet gas can lead to condensation issues, which over time will impact the performance of the system. One operator reported corrosion issues with sour gas used for pneumatic controllers and pumps.

Technical challenges with electronic controllers

- Snow: One operator reported that snow can be a problem with solar panel and battery lifetime.
- Theft or damage: Solar panels have reportedly been stolen or used as targets for shooting.
- Chemical injection pumps: Pumps consume far more energy than controllers/actuators. Sites with a large number of pumps or with pumps with high energy or power demand may represent a challenge for 100% solar powered electric systems. In addition, shortly after completion, some wells may require high volumes of methanol injection, and powering pumps to inject this high volume can strain these systems. Some of the operators interviewed reported that this technical barrier can be solved by bringing a portable stand-alone generator to the site for a few weeks to ensure that the power requirement is met.
- Safety considerations: Due to the very low voltage of the system, the safety risks are considered acceptable by the operator who evaluated this risk.

Applicability of electronic controllers
According to interviews with operators, this solution can technically be implemented on any well site. Generally, for the sites with these systems in place, the pressure differential is up to 2000 psi and the pipe diameters are between 2- 3 inches, but the system can be designed for larger pressure drops and larger diameters as required.

[6] When properly designed (e.g. with sufficient reserve margin in the batteries), recent solar powered electric systems do not require back-up generators, due to the reduced cost of solar-panels and the availability of low-power components. These systems are routinely installed without back-up generators in North America, including in Northern Canada where in winter there is only 1 to 2 hours of full sunlight a day. [9]

The only general limitation is the incremental costs. According to the operators, given the current gas prices, implementation costs are not compensated by the value of the gas saved. The project can be economical when other factors such as lower maintenance costs improve the return on investment.

Note on Emergency Shut-Down Valves (ESD): As a rule, electric controllers/actuators will stay in position if the system fails and power is lost, wires are cut, or other failures occur. This differs from some other solutions that can be designed so that valves close (or open) if the system fails (for example if the supply gas pressure is lost). Although Calscan is developing a “fail safe” electric ESD, operators have reportedly been using pneumatic or hydraulic ESD valves, as they are “fail-safe”.

Sunlight: In northern latitudes (e.g. northern Alberta) and when the energy demand is high (e.g. several pumps), solar panels may not generate enough power, in particular for chemical injection pumps. Other power sources such as thermal electric generators or methanol fuel cells have been used in pilot implementations.

Electronic controllers at medium and large sites: Due to the market conditions, providers have so far focused mainly on the development of solutions for small sites in remote locations. There thus seems to be much less field experience with using electronic controllers at medium and large sites. No technical barriers were identified for the installation of electronic controllers in sites with available electricity. Given the recent progress in both solar panel technologies and large battery solutions, solar-powered solutions may also be appropriate for large sites without available power. However, we are not aware of any such installations. Therefore, to be conservative, we do not examine the use of electronic controllers at large sites without electricity available.
Medium or large sites may also be the result of a combination of a number of small sites (e.g. several well pads). In practice, several small independent electronic controller installations can thus be installed on one medium to large site.

Suppliers

The following table presents a non-exhaustive list of relevant providers:

Table 4: Non-exhaustive list of relevant providers:

Name of the suppliers	Website	Offer	Comments
Calscan	http://www.calscan.net/products_bearcontrol.html	Provide full customized system	Cascan’s Bear Solar Electric Control System is designed mainly for well head separators, but it can also be used in other applications. It includes solar panels, batteries, electric actuators, control valves, switches, control panels and other control equipment.
Spartan	http://www.spartancontrols.com/	Provide full customized system	Spartan designs electronic control systems assembling a number of components including Emerson/Fisher electronic controllers and actuators.
Ameresco	http://www.amerescosolar.com/solar-power-solutions-oil-and-gas-industry	Provide full customized systems	Amaresco Solar designs customized off-grid solar power systems.
Emerson/ Fisher		Manufacture elec. controllers and actuators	Different brands under Emerson Process Management (including Fisher, EIM) supply electronic and electro-pneumatic control components (controllers, positioners, actuators, control valves, transducers, etc.)
Exlar	http://exlar.com/	Manufacture elec. actuators	Exlar currently offer electric actuators that can replace pneumatic actuators.

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3.3 Instrument air

Instrument air controllers are systems where pressurized natural gas is replaced with compressed air as a source of energy and signaling medium for pneumatic controllers and pneumatic actuators. Since controllers use air, instead of natural gas, they only vent air to the atmosphere, eliminating emissions from pneumatic controllers. Instrument air controllers are applicable to both new sites and existing sites; however, the technology can only be implemented when a reliable power supply is available.

This section provides a description of the benefits, the costs, and the applicability of instrument air controllers and is mainly based on interviews with oil companies, reviewing their recent experience installing instrument air systems.

Description of the technology
Instrument air technology is a well-established mature solution to run pneumatic control systems and is widely applied globally. In many countries (e.g. Norway, Iran, Kazakhstan [11]), the majority of the pneumatic control systems run on instrument air.
Systems typically include:

- Heavy-duty industrial air compressors. Two compressors are generally installed for redundancy, but for cost reasons, an operator has reported using only one.
- Air dryers - part of the air compressor package.
- Wet air receiver tank - part of the air compressor package.
- Dry air receiver tank - helps provide a buffer to secure longer system autonomy in the event of a power outage or demand surge.

Investment costs
Interviewers highlighted that the investment costs for instrument air installation vary significantly from site to site, depending on the layout and the type of equipment already on site. Investment costs can be classified as follows:

- Air compressor package: This includes the purchase of the main equipment (compressors, dryers and air receiver tanks). The size of compressors, dryers, and other equipment depends on the number of pneumatic controllers to be supplied with compressed air, and on their specifications (i.e., their demand for compressed air). A small compressor station would require around 5 HP of air compression capacity, while a larger facility would require up to 20 HP. This system can be purchased as individual components or as a package, for between $20,000 and $70,000 [12].
- Mechanical & installation costs: Mechanical and civil work may be required, depending on the layout of the existing facility. These costs are often higher for older facilities and can include:
    - Pipe cleaning and upgrades.
    - Trenching and tubing installation, since large sites may have several independent natural gas supply systems for controllers and pumps, and air would need to be piped through the full site.
- Electrical/instrumentation equipment and supplies: Depending on the site and the specific project requirement, this category may include:
    - Remote terminal unit or SCADA system installation or upgrade. The control system for some plants (e.g. shutdown/start-up, safety systems etc.) may have to be upgraded to accommodate the air compressor package.
    - Upgrades and wiring needed to add the additional electrical loads from the air compressor motors.
    - Repair/replacement of a controller in case of malfunctioning controller.
- Engineering/consulting: The site might require additional expenditures for electrical engineering and consulting.

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Although air compressors and their auxiliary equipment represent a large part of the CAPEX, the engineering, preparation and installation costs can comprise up to 70% of the total upfront investment. Installation and preparation costs may include electrical and instrumentation supplies, mechanical and civil works, additional wiring, piping, valves and fittings. These costs are higher for older facilities that are not capable of handling the extra power, or don't have a suitable layout for utilities. Overall, the total cost for a project varies between $50,000 and $250,000 [10].

Maintenance costs
Maintenance costs typically include:

- Power consumption
- Air compressor servicing, generally every 6 months.

Benefits of instrument air controllers
Operators highlight a number of benefits:

- Revenue from the sale of gas: Instrument air eliminates methane and VOC emissions and thus increases the volume of gas available for sale.
- Reliability**:** The instrument air system is a highly reliable alternative to a natural gas driven pneumatic system for grid-connected facilities.
- Reduced maintenance costs**:** Although there are some additional operating costs with the deployment of air systems, some maintenance expenses are cut as a result of stopping the use of natural gas, particularly wellhead gas (or separator gas). Due to fluctuations in the GOR, some operators reported gas shortages on-site and thus they had to use other sources, such as propane, or to purchase gas from an adjacent field. Maintenance costs due to liquids condensing in the system or sour gas damage are also avoided by replacing untreated natural gas with air.

Applicability of instrument air controllers
Two main applicability limitations were identified during the interviews:

Size of the installation:
Instrument air controllers require heavy duty industrial air compressor packages designed for continuous duty (24/7). This in effect precludes the use of air compressors smaller than 5 HP, since available 2-3 HP air compressor packages present reliability problems. One operator reported that the one-year lifetime of a smaller compressors makes them unacceptable, so a minimum of 5 HP is assumed.

Access to power
Instrument air systems may only be used in locations with access to a sufficient and consistent supply of electrical power. Operators have used instrument air at:

- Grid connected sites.
- Sites with onsite power generation. Many sites (e.g. compressor plants) have power generation for other purposes: lighting, automation and control systems, etc. The same system can also be used for instrument air if generation capacity is available. We note that a sufficient, reliable, good quality gas stream is required for power generation. Wet or sour gas may not always be used for on-site power generation, depending on the specification of generator engines, etc.

In theory, diesel powered instrument air could be installed; however, this project identified no concrete examples of this technology. One operator stated he considered, and then rejected, the use of diesel to run air compressors, due to the high costs and low perceived environmental benefits.

3.4 Other technologies

This section reviews other “zero emission” technologies at various stages of maturity. In general these technical options are either (i) not widely applicable (such as self-contained controllers and vent gas recovery) or (ii) fewer than 100 installations were identified as part of this project (such as solar powered instrument air).

Solar powered instrument air
This study identified about 40 installations of small, energy efficient motor-compressors powered by solar panels/batteries, to replace natural gas with instrument air as the pneumatic medium. TRIDO industries, the technology provider interviewed as part of this study, indicated that these systems have a maximum capacity of ~20 scfh, making them suitable for some small to medium sites which use a few low-emitting controllers. High-bleed controllers have to be retrofitted to reduce air consumption in order to reach the feasible level. Despite the lack of extensive deployment so far, an attraction of this solution lies in the fact that controllers and actuators do not need to be replaced.

Instrument air powered by other power sources
Other power sources, such as thermal electric generators or methanol fuel cells, have been used in pilot implementations to power traditional instrument air systems.

Vent Gas Recovery
Re-routing to VRU
Vapor Recovery Units (VRUs) have a long, well-established track record in the upstream oil and gas industry to recover VOCs and methane from vented sources. Typically, they consist of capturing and piping equipment, a de-liquefaction drum, and compressor(s) to inject the recovered gas into pipelines. In theory, all vent lines can be connected to the VRU, including pneumatic controllers’ lines.

Nevertheless, there have been limited implementations (only one example identified in this study) of well-site vent gas recovery projects using the recovered gas from pneumatic controllers in non-engine applications. SlipStream®, as further presented below, is a technology that facilitates recovery of the gas and use of it in gas-fired engines. Another technology, Cata-Dyne™, utilizes the recovered gas as a feed to a small, flameless appliance that converts natural gas or propane into infrared radiant heat that is usable if industrial heating is required.

SlipStream®
Spartan’s SlipStream® system captures vented hydrocarbons and uses them as a supplementary fuel source for natural gas-fired engines, reducing fuel consumption. This technology can thus be applied only to sites with gas-fired engines, e.g. compressor engines. Despite concerns about costs, one operator emphasized specifically the reliability of the technology, as it reportedly does not interfere with normal operations. Nevertheless, if the volume of gas emitted by the combined vents (including the controllers) exceeds the engine fuel requirements, natural gas would still be vented or otherwise controlled.

Self-contained (aka Bleed-to-Pressure or Integral Pneumatic Controllers)
Self-contained systems are designed to contain the gas typically vented from controllers and then discharge it to the control valve’s downstream piping, thus resulting in zero emission.

A number of operational requirements limit the applicability of self-contained systems, the most important of which is the need for a high differential pressure across the control valve [6,13]. For instance, GE’s Bleed-to-Pressure system requires more than 80 psi, and both GE and VRG Controls require a downstream pressure of maximum 300 psi [13]. Also, sour or untreated gas could cause disturbances in

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the operation of self-contained controllers. Nevertheless, if applicable, the technology may be cost-effective or economical in cases where the total baseline emissions are high.[7]

Due to the limited applicability or the lack of widespread field experience, the technologies described above are not further analyzed in this report. However, depending on the site specifics, these options may be applicable and cost-effective, and can represent useful alternatives to instrument air or electronic controllers; thus they are presented as potential alternative options in section 4.4.

4. Cost effectiveness of electronic controllers and instrument air

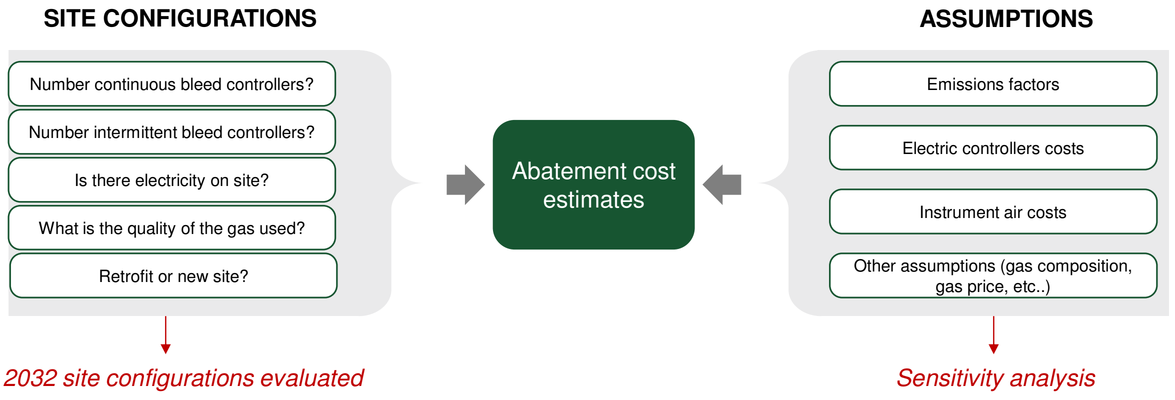
This section presents an analysis of the *cost-effectiveness* – net cost in USD per ton of avoided pollution – of employing the two main zero emission technologies, air-driven pneumatic controllers and electronic controllers, instead of natural gas-driven pneumatic controllers at new and existing sites. These results are applicable at both oil and gas production sites (well pads) and compressor stations.

4.1 Analytical approach

The cost-effectiveness of zero emission technologies will vary with the number and type of controllers at a site, in addition to many other factors, as we discuss below. Given the variety of site configurations (number and type of controllers per site, connection to the grid, type of gas handled) across the US, and the lack of information on the frequency of occurrence of these configurations, we opted to carry out cost-effectiveness assessments for both electronic and instrument air controllers for a broad spectrum of permutations of those site configuration parameters.

A number of assumptions have been made for the analysis. Key assumptions are discussed in the section below; all assumptions are detailed in the Appendix.

Figure 7: Overview of the methodology



For each permutation of the site configuration parameters, a CH_4 abatement cost (cost per metric ton of avoided pollution) was estimated.

[7] A technology provider reports an average of less than \$3000 per Bleed-to-Pressure control system, leading to a payback period of less than 2 years for replacing 8 controllers.

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For this analysis, a zero emission technology implementation is considered
- "economical" if the CH_4 abatement cost is negative (i.e. if the project NPV is positive)
- "cost effective" if the CH_4 abatement cost (net cost per ton of abated pollution) is lower than the social cost of methane that EPA has used in recent regulatory analyses [19] (Social cost of methane for 2020, calculated with a 3% discount rate, $1354 (2016 USD). [8]

The following sections provide more insight on:
- The abatement cost calculation
- The main assumptions
- The site configurations evaluated.

Abatement cost calculation – methodology

For each site configuration, the following were estimated:
- The CAPEX and OPEX of the zero emission technology implementation (either electronic controllers or instrument air)
- The CAPEX and OPEX of the baseline scenario (i.e. the cost incurred by the operator if the conventional pneumatic technology had been used instead of zero emission systems)
- The emissions of CH_4 and VOC under the baseline scenario

Since methane and VOC emissions will be zero if the zero emission technology is used, the abatement cost (in $/t CH_4) is then estimated as follows:

$$Abatement\ cost \ = - \frac{NPV(Cash\ flow_{zero\ emission\ project} - Cash\ flow_{baseline\ scanerio})}{NPV(Emission_{baseline\ scanerio})}$$

This approach, and its underlying assumptions, is compared to the annualized cost approach typically used by EPA in the appendix.

Main assumptions

The following table provides a list of the main assumptions applied. A full list of assumptions is available in the Appendix.

Table 5: Central assumptions

Description	Central Assumption	Comment
Gas price	2 $/Mscf	The value of recovered gas has been assumed to be similar for all emission sources, independent of the composition of the gas. Gas values from 1 to 3 $/Mcf have been assessed in sensitivity analyses.
Discount rate	7%	A 7% per year real term discount rate has been assumed. A sensitivity is presented for a 3% per year real term discount rate. This approach is consistent with EPA/BLM practice.
Remaining lifetime for a new project	15 years	The lifetime for new controller installation is assumed to be 15 years in line with EPA practice.
Remaining lifetime for retrofit project	10 years	The remaining lifetime for existing sites is assumed to be 10 years. A sensitivity is presented for a 5 years remaining lifetime.
Gas composition	0.0167 tCH_4/Mscf	Gas composition assumptions for dry gas (wet gas assumptions are presented in the Appendix)
	0.0046 tVOC/Mscf	

[8] EPA reports that the 2020 social cost of methane (mean value at 3% discount rate) is $1300 / metric ton of methane in 2012 USD; this is adjusted to $1354 / metric ton of methane in 2016 USD using a 4.2% cumulative inflation rate.

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Average emissions factors assumptions

The emission factors used for this analysis are conservative averages based on the literature review (See section 2.3). The following table presents the emission factors used and the rationale for each value.

Table 6: Emission factors assumptions – central assumptions

Description	Central Assumption	Comment
Continuous-bleed controller(s) – retrofit sites only	14.4 scfh	This emission factor is applied for all the continuous bleed controllers on retrofit sites. Assumption based on [2] (Company classification into EPA categories excluding ESD)
Low bleed continuous controller (s)	1.39 scfh	This emission factor is applied for all the continuous bleed controllers on new sites. Current federal regulation (OOOO) requires that new continuous bleed controllers be low bleed. Assumption based on [16], most conservative average value between [16], [3], [4] and [2]
Intermittent-vent controller(s)	4.4 scfh	Assumption based on [2], most conservative average value between [16], [3], [4] and [2]
Chemical injection Pumps	13.3 scfh	Assumption based on [16], most conservative average value between [4], [7] and [16]
ESD	0.41 scfh	Assumption based on [2], average of the controllers classified as ESD

While measurements show that emission factors vary widely in the field, using conservative average emission factors, we are able to calculate conservative (i.e. high) abatement costs for widespread adoption of zero-emitting technologies. Sensitivity analyses are presented in the section 4.2 to reflect the field variability, which impact the site specific abatement costs.

Site configurations evaluated

As described above, we performed economic modeling on a total of 2032 permutations of site configuration parameters, covering a wide range of possible combinations of site parameters.

The following parameter inputs were used to construct the site configurations:

- Total number of controllers – from 1 to 40 controllers.
- A varying mix of continuous-bleed and intermittent-vent controllers (from 0% to 100% of intermittent-vent controllers).
- One emergency device (ESD) was added for every five controllers[9] (rounded up).
- New site (construction of new facilities) or retrofit (upgrade of existing facilities).
- Access to electricity or not.
- Whether pneumatic driven controllers currently operate on dry gas or wet gas.

To simplify the presentation of the results, the 2032 possible site configurations were then grouped into 20 larger categories depending on the total number of controllers, the presence of electricity on site, and whether the site is new or would need to be retrofit with zero emission controllers. The following table presents a matrix of the 20 different categories of site configurations evaluated, with the number of sites in each category presented in green. Each cell of this table includes a number of site configurations

[9] This number of ESDs has no impact on the final conclusion. Operators do not currently replace ESDs with electric controllers, so number and the emission factor of ESD have no effect on the cost-effectiveness of electric controllers. On the other hand, ESDs will generally be converted to instrument air, but the effect of including reasonable numbers of ESDs on the final cost-effectiveness is small due to the small air consumption of ESD. In this context, the assumption on the number of ESD did not affect the final number of sites with an abatement cost higher than the social cost of methane.

depending on the number of intermittent-vent or continuous-bleed controllers and the type of gas used to power the controllers.

Table 7: Site configurations categories (number of site configurations presented in green)

Number of Pumps	Number of controllers (excluding ESD)	New sites		Retrofit	
		No elec. on site	Elec. on site	No elec. on site	Elec. on site
0	**1 to 3 controllers**	18	18	18	18
	4 to 10 controllers	56	56	56	56
	11 to 20 controllers*	98	98	98	98
	21 to 40 controllers*		164		164
1	**1 to 20 controllers***	172	172	172	172
	21 to 40 controllers*		164		164

* Based on the analysis presented in section 3, we did not model either technology for larger sites (≥21 controller excluding ESD) without electricity on-site

- Electronic controllers were modeled at sites of all sizes with electricity available, and smaller to medium sites (up to 20 controllers) with no electricity available. Medium and large sites with electricity on-site are presented, as no technical barriers were identified for the installation of electronic controllers in such installations. However, there seems to be much less field experience for these types of installations compared to smaller sites.
- Instrument air was presented at larger sites with electricity available. For sites smaller than 20 controllers, electronic controllers were always more cost efficient than instrument air (see below).

This approach reflects the current industry experience and practice as presented by the interviewees. It is, however, important to highlight that the threshold in terms of number of controllers (20 in the analysis), depends in reality on site-specific parameters, and should only be considered as an **illustrative** threshold based on information available.

4.2 Main findings – electronic controllers

The findings of the cost-benefit analysis for electronic controllers are presented in four different sections:

- First, the full cost-benefit analysis is presented for one site configuration, to illustrate the methodology by exploring one example in detail.
- Second, a sensitivity analysis is performed for the same site configuration to show the impact of the main assumptions.
- An overview of the results for all the site configurations evaluated is then presented.
- Finally, the impact of the emission factors assumptions is described.

Example of abatement cost estimate for one example site configuration

The following table presents a full analysis for an example site configuration. The project is the retrofit of an existing site with four different controllers (one continuous-bleed, two intermittent-vent, one ESD and no pump) which represents the most common number of controllers in [8,2]. The site is not connected to the grid and currently uses dry supply gas for the controllers.

Table 8 presents the CAPEX estimate for the conversion to electronic controllers. As the project is a retrofit project, the baseline CAPEX is zero.

The detailed assumptions for the size of the electronic system (such as number of solar panels and battery requirements) are presented in the appendix. Overall, the system is oversized and always includes, for example, 10 days of energy storage.

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Table 8: CAPEX estimates for electronic controller implementation (central assumptions)

Item	Assumption	#	Total USD
Controllers	$ 4000/unit	3	12 000
Control Panel	$ 4000/unit	1	4 000
140 W Solar Panel	$500 /Unit	1	500
100 Amh battery	$400 /Unit	3	1 200
Installation and engineering costs	20% of equipment costs	NA	3 540
Total CAPEX			**21 240**

Table 9: Emissions estimates (central assumptions, new sites)

Whole gas emissions in scfh	EF assumption	#	Total
Intermittent – vent controllers	4.43	2	8.9
Continuous –bleed controller	14.4	1	14.4
Total gas emissions			**23.3**

In terms of OPEX, it is assumed that batteries are replaced every 4 years and solar panels every 10 years. Given the operators' reports of minimal maintenance for electronic controllers, it has thus been assumed, conservatively, that general maintenance costs for are similar to those for continuous-bleed controllers functioning properly[10]. We do not include any estimate of savings in inspection costs due to automation (conservative assumption). Table 9 above presents emission estimates for the baseline scenario and finally Table 10 includes the abatement costs estimated.

Table 10: Final results – central assumptions

Item	Unit	Value USD
CAPEX	$	21 240
Value of the gas saved	$/year	408
NPV of the OPEX	$	1 672
NPV	$	-19 266
ABATEMENT COSTS	**$/tCH$_4$**	**751**

As presented in Table 10, for the small and remote site configuration presented, the abatement costs is well below the social cost of methane as defined above. The abatement cost for same site configuration, but at a new facility, as opposed to a retrofit, is estimated to be $847/ton CH_4. The difference is due to the difference in baseline costs and baseline emissions between new and retrofit sites (see below).

[10] Which is lower than the maintenance costs for continuous bleed controllers operating with wet supply gas.

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Info Box 1: Electric conversion of pneumatic pumps

Pumps at well sites and well pads are typically used for methanol, corrosion inhibitor, de-waxing agents, or soap injection. Federal regulation (OOOOa) rules already require that emissions from new and modified chemical injection pumps be controlled in a number of circumstances.

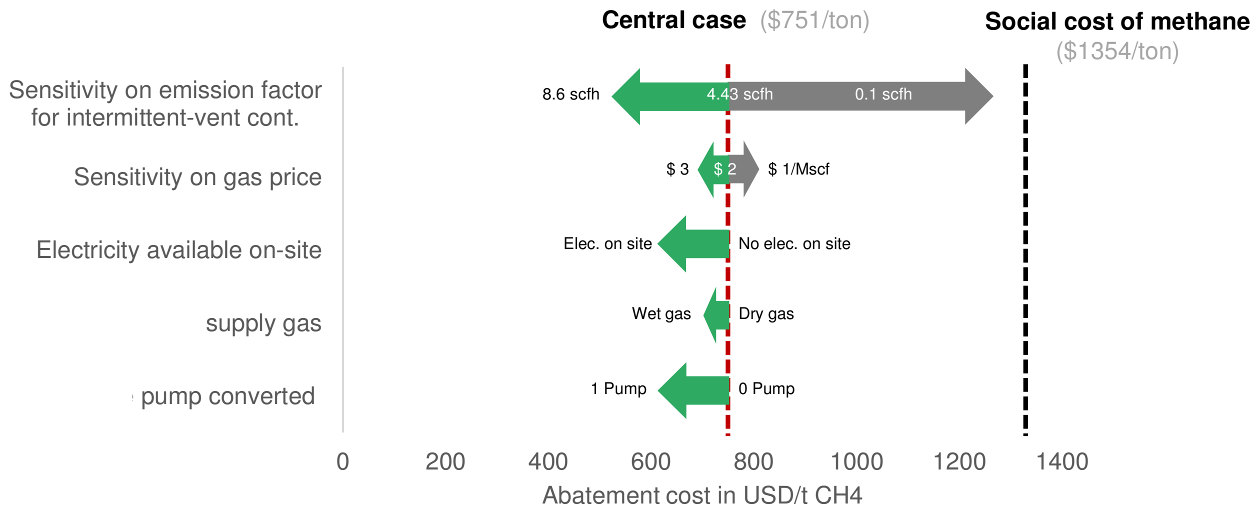
As highlighted in Section 3, conversion of chemical injection pumps to electric is both a mature and a cost effective technology.

In the analysis presented in this section, the conversion of one chemical injection pump per site is presented as a potential added benefit for the project developer. In cases with many pumps, or of major energy requirements for the pumps, the conversion of pumps to zero emission technologies could be assessed as a separate emission reduction project.

Sensitivity analysis for one example site configuration

In this analysis, a number of assumptions have been made which impact the abatement cost. The following figures present sensitivity analyses for the site configuration described in the previous section, for both the retrofit case and the new site case. We examine the sensitivity of the abatement cost to changes to a few key sensitivities. A more exhaustive sensitivity analysis is presented in the appendix.

Figure 8: sensitivity analysis – electronic controllers - retrofit



The next figure presents a similar sensitivity for the same site configuration, but at a new facility as opposed to a retrofit.

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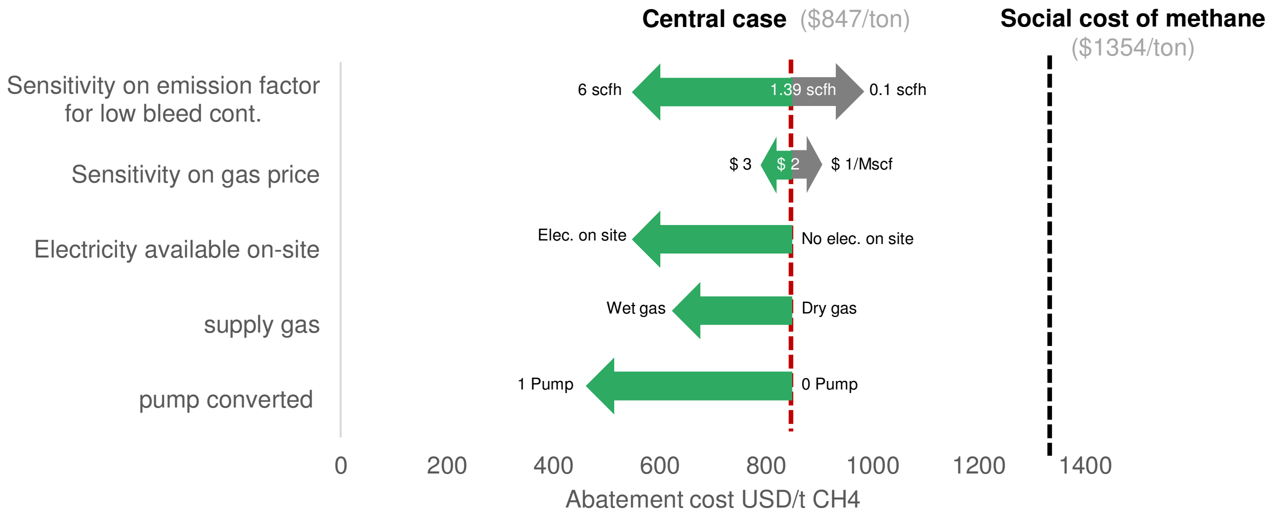
Figure 9: sensitivity analysis – electronic controllers - new



The emission factor has by far the largest impact on the abatement cost and clearly heavily impacts the cost effectiveness of the option for retrofit sites. Excluding the emission factors, the other assumptions impact up to +33% of the abatement costs and no sensitivity leads to an abatement cost higher than the social cost of methane (see appendix).

In general terms, the abatement cost is more sensitive to changes for new sites than for retrofit sites. This is due to the fact that both the incremental costs and the emissions reductions are much smaller for new sites than for retrofit sites. A small change in either of these is thus relatively larger for new sites than for retrofit sites.

The following few paragraphs describes in more detail the impact of the main assumptions:

Electricity on site

The investment costs for sites without an electricity supply are higher than for sites with electricity due to the need to install solar panels and batteries. As a result, the abatement cost for site configurations with electricity is generally ten to one hundred percent lower than for site configurations without power. In a few site configurations the abatement cost is negative (i.e. NPV>0).

Wet versus dry supply gas

Operators have reported that the quality of the supply gas affects maintenance costs. Even slightly wet (or sour) gas can lead to condensation (or corrosion) issues, which over time will impact the performance of the system. The maintenance cost for sites with wet supply gas is estimated at $200/year/controller [10] compared to $80/year/controller for dry supply gas [18]. As a result, sites with wet gas have an abatement cost generally 5 to 100 % lower than sites with dry gas, and, in a few site configurations, the abatement cost is negative (i.e. NPV>0). Gas quality is also likely to impact the average emission rate. Due to the lack of quantitative data on this impact, however, this factor has not been taken into consideration during the analysis, but it would reduce the abatement costs of sites with wet gas even lower.

Chemical injection pumps

As pumps have high emissions factors, sites where one pump (or several) can be converted to electric power have much lower abatement costs than sites without. All the sites with one pump have an

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abatement cost lower than the social cost of methane. In addition, the abatement cost of converting a single chemical injection pump (without any controller) to a solar powered electric pump is lower than the social cost of methane in all the sites configurations evaluated.

New versus retrofit sites

The costs and the emissions abatement structures differ greatly for new and for retrofit sites. The main differences include:

- The incremental CAPEX (i.e. the difference between the zero emission technology CAPEX and the baseline CAPEX) for a retrofit site is usually much higher than for a new site.
- Given the current regulatory framework, it is assumed that new sites use low-bleed continuous controllers as a default, and we conservatively use the EPA emissions factor [1] for these controllers, despite measurements showing higher emissions for low-bleed controllers [3,4]. The emissions reduction for retrofit sites is higher than for new sites, as we use an emissions factor based on actual measurement [2] for continuous-bleed controllers at existing sites.

The first difference makes the abatement cost higher for retrofit sites than new sites, while the second difference has the opposite effect. Overall, in the vast majority of the site configurations evaluated, the abatement cost for new sites is higher than for the equivalent retrofit site configuration.

Overview of the results for all the site configurations

Overall, the abatement costs for electronic controller installations at 2032 site configurations were estimated during this project. Under the central assumptions, 20 of the 2032 site configurations evaluated have abatement costs higher than the social cost of methane, $1354/t. The following table shows in red the number of site configurations with abatement costs higher than that figure for each category.

Table 11: Number of site configurations with abatement costs superior to the social cost of methane – central assumptions

Number of Pumps	Number of controllers (excluding ESD)	New sites		Retrofit	
		No elec. on site	Elec. On site	No elec. on site	Elec. On site
0	**1 to 3 controllers**	**6 / 18**	**4 / 18**	**5 / 18**	**2 / 18**
	4 to 10 controllers	**2 / 56**	**0 / 56**	**0 / 56**	**0 / 56**
	11 to 20 controllers*	**0 / 98**	**0 / 98**	**0 / 98**	**0 / 98**
	21 to 40 controllers*		0 / 164		0 / 164
1	**1 to 20 controllers***	**0 / 172**	**0 / 172**	**0 / 172**	**0 / 172**
	21 to 40 controllers*		0 / 164		0 / 164

* Sites with more than 10 controllers were presented for the installation of electronic controllers. However, there seems to be much less field experience for this type of installation, compared to smaller sites. Sites with more than 20 controllers and without electricity on-site were not modelled. Though no major technical barriers were identified, we could identify no examples of installations of solar powered electronic controllers on very large sites.

A number of conclusions can be drawn from this analysis. Under the central assumptions:

- For almost all the site configurations evaluated with four or more controllers (excluding ESDs), it is cost-effective to install electronic controllers.
- For all site configurations evaluated with one chemical injection pump, it is cost effective to install electronic controllers.

A site configuration is not cost effective if the volume of gas saved does not justify the cost of implementation. In general, for a given type of site configuration (wet/dry, on or off grid, new or existing, share of intermittent controllers), the cost-effectiveness improves (fewer $/ton) with the number of controllers.

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In addition, we can highlight the following patterns for the site configurations with abatement costs higher than the social cost of methane:

- For new facilities, these sites have only low-bleed continuous controllers (5 or fewer). The low bleed emission factor assumption has an important impact on the conclusion (see below).
- For retrofit facilities, these sites have only intermittent-vent controllers (3 or fewer). For retrofit sites, the emissions factor used for intermittent-vent controllers is less than that used for continuous bleed controllers (see section 4.1)

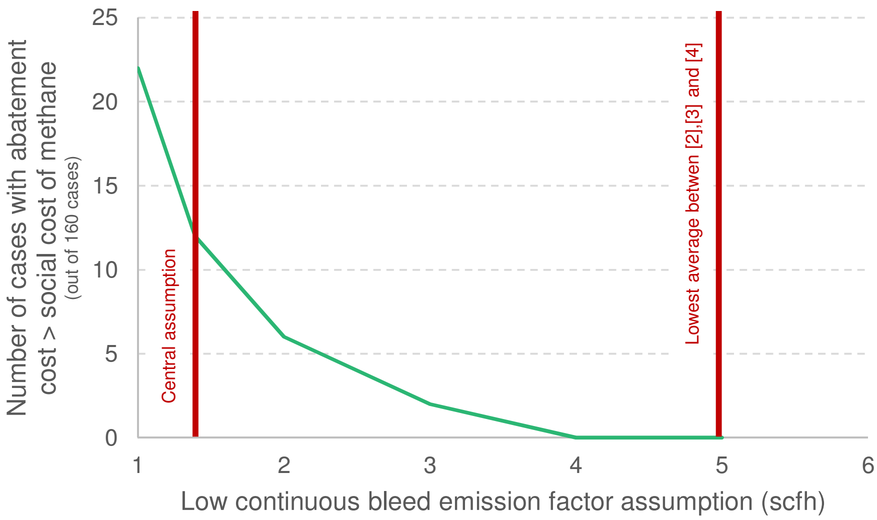
The full list of site configurations with an abatement cost higher than the social cost of methane is presented in the appendix.

Impact of the emission factors assumptions

The results of the analysis are quite dependent on the emissions factors used for the various types of pneumatic controllers.

The following graph illustrates the impact of the continuous low-bleed emission factor on the cost effectiveness of new sites with at least one continuous low-bleed device. This represents 12 of the 19 site configurations deemed not cost effective. The central assumption for the low-bleed emission factor is 1.39 scfh. But an emission factor of 4 scfh would make all sites with at least one continuous bleed controller cost effective. It is interesting to compare this figure to the results of past measurement campaigns presented in the Figure 4, which suggest that average emission factors for low-bleed devices are likely higher than 5 scfh.

Figure 10: Impact of the continuous low bleed emission factor on the cost effectiveness of new sites with at least one continuous low bleed device.



In a site without an electricity supply and with just a single controller, an electronic controller is cost-effective if the emissions from that single controller are more than 4.4 scfh for a new site and more than 7.2 scfh for a retrofit site. The point of cost-effectiveness is lower for sites with 2 or more controllers, for sites using wet supply gas, or for sites with on-site electricity. These thresholds should be compared with emissions factors observed in Figure 5 for small and very small sites.

As mentioned above, while emissions from pneumatic controllers vary widely from device to device, this analysis uses average emissions factors based on recent measurements, aiming at evaluating the cost-effectiveness of using electronic controllers on a widespread basis.

To conclude, the analysis shows that conversion to electronic controllers would be cost effective in most site configurations even using conservative average emissions assumptions. If higher emissions assumptions are considered -- as reflected in recent field measurements – virtually all site configurations evaluated would be fall below the social cost of methane

4.3 Main findings – Instrument air

As in the previous section, the finding of the analysis for instrument air is presented in three different sections:

- First, the full cost-benefit analysis is presented for one site configuration, to explain the methodology applied to one example.
- Secondly, a sensitivity analysis is performed for the same site configuration to illustrate the impact of the main assumptions.
- Finally, an overview of the results for all the site configurations evaluated is presented.

Contrary to electronic controllers, instrument air installation is only presented for site configurations with electricity available on-site.

Example of abatement cost estimate for one example site configuration
The following tables present a full analysis for an example site configuration. The project is retrofit of an existing site with 20 different controllers (5 continuous-bleed, 11 intermittent-vent, and 4 ESD). This configuration is illustrative; it is not known how representative it would be of larger sites. The site is connected to the grid or has power already generated on site, and currently uses dry gas for the controllers.

The first table presents the CAPEX estimate for the instrument air project. The detailed assumptions for the size of the instrument air system (share of the air bypassed in dryer, share of the utility air supply,[11] size of compressor, load of the compressor) are presented in the appendix. The approach in terms of system sizing proposed by Natural gas star has been applied [14], after having been quality checked against nine recently implemented projects. Overall, the system is oversized (as per the industry standard) and always includes, for example, one spare compressor. Equipment costs (including industrial grade compressors designed for 24/7 duty) have been assumed using online quotes.

As highlighted previously, installation costs for instrument air are highly site specific. Interviews have reported very low installation costs in particular when retrofitting many sites with similar designs. On the other side of the spectrum, operators have also reported high installation costs in cases where important investments, such as electric system upgrades and trenching between building or clusters of equipment, were required on the installations. The investment cost estimates presented below include some relatively conservative assumptions (i.e., high cost) in terms of equipment and installation costs. Some sensitivities are presented (appendix) to reflect the variability of the local circumstances.

[11] Because it is useful to have compressed air at a site for a variety of tasks and uses, operators typically oversize compressed air systems installed to drive pneumatic controllers. In this analysis, we assume that operators will do so, and consider the costs of the oversized system but do not make any estimate of the value of having compressed air available onsite. This approach is conservative (since operators do not strictly need oversize compression capacity for this purpose to use instrument air for pneumatic controllers), though the effect is not large.

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Table 12: CAPEX estimates for instrument air controller implementation – central assumptions

Item	Assumption	Sizing /#	Value USD
Controllers and installation costs for the controllers	NA	retrofit projects (it is assumed that controller can be re-used)	0
Compressor package (Assuming 2 compressors, air drying unit and wet air receiver unit)	See list of assumption in the appendix [12]	10 HP	32 000
Other supplies costs (Instrumentation Supplies & Pipe/Valve/Fittings, electrical supplies, etc..)	1400 $/cont	20	28 000
Electrical, mechanical & civil Installation Costs, engineering	Retrofit: 100% New: 50% of equipment costs	NA	60 000
Total CAPEX			120 000

In terms of OPEX, it is assumed that compressors are replaced every 6 years. In addition, 4% of the equipment costs are accounted for normal compressor maintenance (typically every 6 months). Other OPEX costs include, for example, electricity costs.

Table 13 presents the emissions estimates while Table 14 present the final results.

Table 13: Emission estimates – central assumptions

Emissions is scfh	EF assumption	#	total
Intermittent-vent Controllers	4.43	11	48.7
Continuous-bleed controllers	14.43	5	72.1
ESD	0.41	4	1.64
Total gas emissions			122.5

Table 14: Final results for the site configuration analyzed – central assumptions

Item	Unit	Value USD
CAPEX	$	120 000
Value of the gas saved	$/year	1073
NPV (Opex)	$	24 683
NPV	$	-121 652
ABATEMENT COSTS	$/t$CH_4$	972

The abatement cost for the same site configuration, but at a new facility, as opposed to a retrofit, is estimated to be $886/ton CH_4. The difference is because the baseline costs are higher and the baseline emissions are lower for new sites than for retrofits.

Info Box 2: Conversion of pneumatic pumps to instrument air

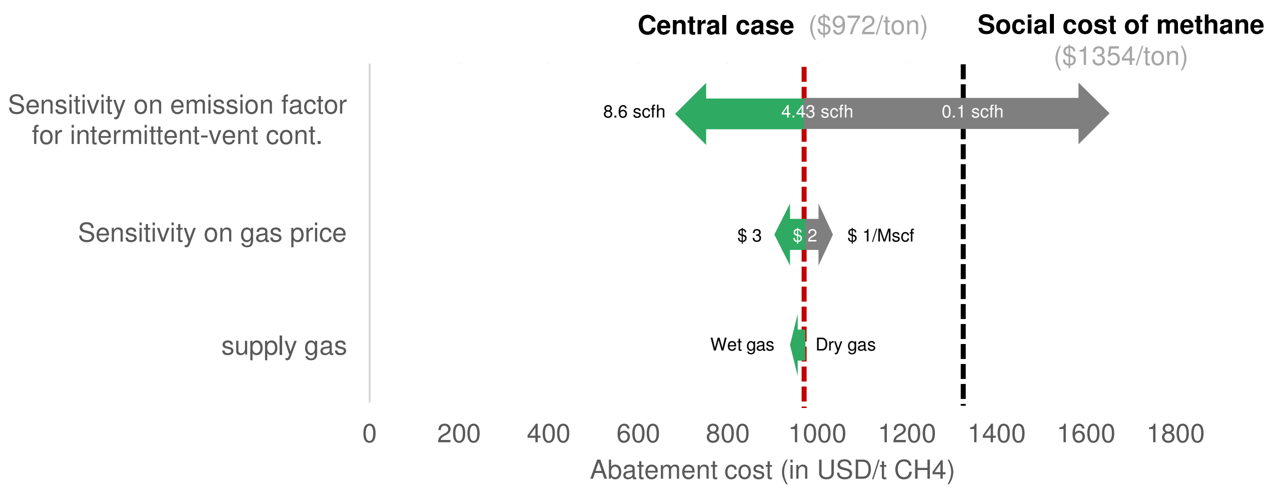
Pneumatic pumps typically emit more per device than pneumatic controllers, so converting pumps to air can represent a large emission reduction and potentially reduce significantly the abatement cost of conversion. However converting pumps to instrument air is not always technically and/or economically feasible. For sites with access to reliable source of electricity, conversion to air is applicable and cost-effective for the majority of chemical injection pumps. However, even for grid-connected sites, conversion to instrument air is not always the preferred option, as electric pumps are proven effective and low-cost.

In summary, in a number of cases, emissions reduction for pumps could be considered as a separate project from controllers. In the follow up analysis, conversion of 1 pump to instrument air is only presented as part of the sensitivity analysis.

Sensitivity analysis for one example site configuration

The following figures present a sensitivity analysis for the same site configuration as in the section above. The CH_4 abatement cost for a few key sensitivities is compared to the abatement cost with the central assumptions. A more detailed sensitivity assessment is presented in the appendix.

Figure 11: Sensitivity analysis – instrument air - retrofit



The next figure presents a similar sensitivity for the same site configuration but at a new facility.

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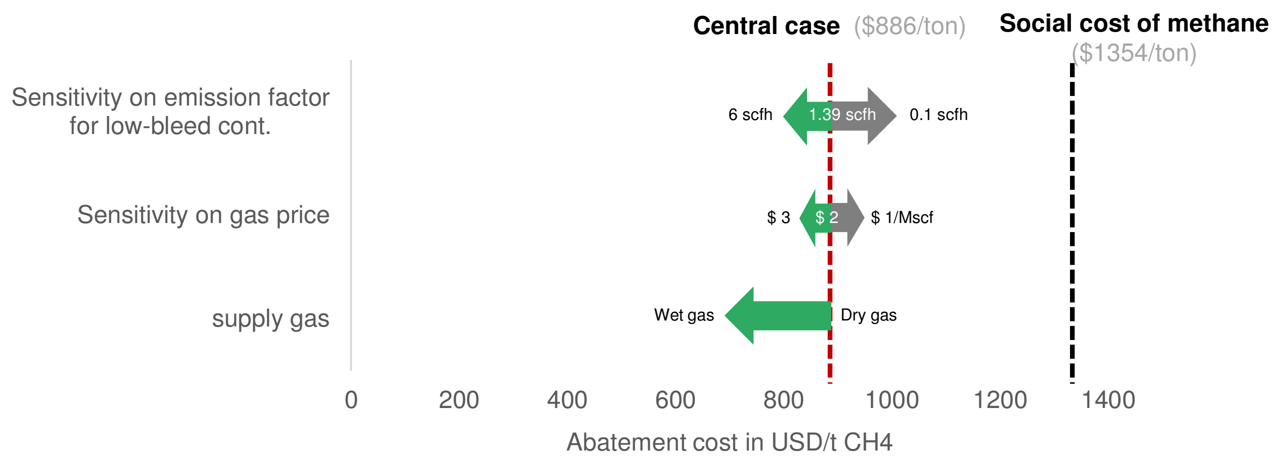
Figure 12: Sensitivity analysis – instrument air - new site



As with the electronic controllers, the emission factor heavily impacts the attractiveness of the option. Excluding the emission factor, no other assumption affects the abatement cost per ton by more than 30% (see appendix).

Wet versus dry supply gas
As with electronic controllers, sites with wet gas have an abatement cost generally 5% to 50 % lower than sites with dry gas due to the difference in maintenance costs.

Overview of the results for all the site configurations
The overall abatement costs for about 328 site configurations, all with an electricity supply and no pneumatic pump conversions, were estimated, with a total number of controllers ranging from 21 to 50 (in various permutations of intermittent-vent and continuous-bleed controllers). Sites with fewer than 20 controllers are not presented, as conversion to electric is cheaper (on a per ton basis) in most of the site configurations with fewer than 20 controllers.

In terms of CAPEX, the total investment for retrofit sites varies between $90,000 and $230,000, while the investment (excluding controllers and their installation) for new sites varies between $60,000 and $120,000.

Under the central assumptions, 5 of the 328 site configurations evaluated have abatement costs higher than the social cost of methane. The following table shows in red the number of sites with abatement costs higher than $1354 /tCH4 for each category of sites.

Table 15: Number of site configurations with abatement costs higher than the social cost of methane – central assumptions

Number of Pumps	Number of controllers (Excluding ESD)	New Sites	Retrofit
0	21 to 25 controllers	3 / 42	0 / 42
	26 to 30 controllers	2 / 40	0 / 40
	31 to 40 controllers	0 / 82	0 / 82

A number of conclusions can be drawn from this analysis. Under the central assumptions:

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- For almost all the site configurations evaluated with more than 21 controllers (excluding ESDs), it is cost effective to install instrument air.
- For all the retrofit site configurations evaluated, it is cost effective to install instrument air.
- In a few of the new site configurations considered, it is not cost effective to install instrument air.

A site configuration is not cost effective if the volume of gas saved does not justify the cost of implementation. The new site configurations with abatement costs greater than the social cost of methane have a vast majority of low bleed continuous controllers, which we have conservatively assumed have very low emissions (1.39 scfh emission factor, see Section 4.1).

The full list of site configurations with abatement costs higher than the social cost of methane is presented in the appendix.

4.4 Summary of the analysis

As described in the section above, an economic analysis assuming conservative average emission factors was performed for 2032 permutations of site configurations with 1 to 50 controllers. Both retrofit and new installations, with or without electricity, were considered. A number of key conclusions can be drawn:

- Zero emission solutions had abatement costs below the social cost of methane (for 2020) described in the EPA 2015 Regulatory Impact Analysis in the vast majority of site configurations considered.
- The abatement costs exceeded the social cost of methane mostly for small sites – those with less than three controllers (excluding ESDs). If higher emission factors, as reflected in field measurements, are used, the abatement costs at even the very small sites fall below the social cost of methane.

The following figure presents a summary of both the technical applicability and economic attractiveness of the different zero emission technologies under different categories of sites. Though this analysis does not provide a detailed evaluation of the distribution of the sites in the US for each of the categories below, existing studies have suggested that the vast majority of the sites have less than 20 controllers.

Table 16: Summary table

			Both retrofit and new sites					
Type of of site		**Number of controllers** (excl. ESDs)	1- 3		4-20		21-40	
		Electricity on-site?	Yes	No	Yes	No	Yes	No
Main options: Electric controller Instrument air		**Description** (of the most economic option which is technically feasible)	Grid connected **electric** controller	Solar powered **electric** controller	Grid connected **electric** controller	Solar powered **electric** controller	Instrument **air**	
		Number of cases not cost effective (i.e. abatement cost > social cost of methane) **under central assumptions**	6 / 36	11 / 36	0 / 308	2 / 308	5/ 328	
		Cost effective for <u>every</u> site configuration if emissions factors are:*	> 5.6 scfh for retrofit > 2.8 scfh for new sites	> 7.2 scfh for retrofit > 4.4 scfh for new sites	> 3.6 scfh for retrofit > 1.4 scfh for new sites	> 4.2 scfh for retrofit > 1.8 scfh for new sites	> 4.5 scfh for retrofit > 1.8 scfh for new sites	
Other options potentially applicable depending on the local conditions	Limited applicability	Vent gas recovery	✓	✓	✓	✓	✓	✓
		Instrument air powered by gas	Not relevant	Not relevant	Not relevant	Not relevant	Not relevant	✓
		Self contained controllers	✓	✓	✓	✓	✓	✓
	Limited known implementations	Solar powered instrument air	Not relevant	✓	Not relevant	✓	✗	✗
		Electric controllers powered by other power sources (TEG, fuel cell)	Not relevant	Not relevant	Not relevant	Not relevant	Not relevant	✓
		Large solar powered electric controller (no known implementations)	Not relevant	Not relevant	Not relevant	Not relevant	Not relevant	Potential solution,** but no example known.

* Emissions factors thresholds listed are determined for the site configuration with the highest abatement cost within the category.
** Based on other solar applications.

The applicability of electronic controllers for small sites and instrument air for large sites reflects the current industry experience and practice as presented by the interviewees. It is, however, important to highlight that the threshold in terms of number of controllers (20 in the analysis), depends in reality on site-specific parameters, and should only be considered as an illustrative threshold based on information available.

Due to the market conditions, electronic controller providers have so far focused mainly on the development of solutions for small sites in remote locations. There thus seems to be much less field experience with using electronic controllers at medium and large sites; however, no technical barriers were identified for this type of installation.

These analyses indicate that the widespread adoption of zero-emitting technologies is cost effective in the vast majority of the site configurations considered. Furthermore, several factors listed should be considered:

- Conservative (low) average emissions factors have been used for low-bleed pneumatic controllers, even though recent research indicates that actual average emissions from those pneumatic controllers may be higher.
- Some of the important benefits of switching to zero-emitting technology, such as the ease of automation or remote operations associated with electrifying pneumatic controllers, are not included in our analysis of the cost-effectiveness of using zero emission technologies.
- Finally, pneumatic controllers emit natural gas, which includes (in varying amounts) other pollutants aside from methane, such as volatile organic compounds (VOCs), which are precursors to ground level smog, and toxic hazardous air pollutants (HAPs). Replacing natural-gas driven pneumatic controllers with zero-emitting technologies will eliminate emissions of these other

pollutants, in addition to emissions of methane, but we have not included the benefits of VOC or HAP abatement in our calculation of abatement costs for methane.

5. Reference list

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[5]	Fort Worth Natural Gas Air Quality Study ERG2012 https://www3.epa.gov/ttnchie1/conference/ei20/session6/mpring.pdf
[6]	API Comments on Oil & Natural Gas Sector Pneumatic Devices by EPA Office of Air Quality Planning and Standards, June 2014
[7]	Quantifying cost-effectiveness of systematic Leak Detection (LDAR) using infrared cameras, Carbon limits, 2014 (including the database used for the analysis) http://www.carbonlimits.no/project/quantifying-cost-effectiveness-of-systematic-leak-detection-ldar-using-infrared-cameras/
[8]	Pneumatic Controller Emissions from a Sample of 172 Production Facilities Prepared by Oklahoma Independent Petroleum Association, 2014 http://www.oipa.com/page_images/1418911081.pdf
[9]	Information provided by technologies suppliers.
[10]	Information provided by operators.
[11]	Methane abatement potential from oil and gas systems in Kazakhstan Carbon Limits, 2016 http ://www.carbonlimits.no/project/methane-abatement-potential-from-oil-and-gas-systems-in-kazakhstan/
[12]	Online quotes for equipment purchase March – April 2016
[13]	Reducing Emissions Through Retrofitting of High Bleed Devices – GE 2012 https://www.epa.gov/gasstar/documents/workshops/2012-annual-conf/giernoth.pdf
[14]	Convert Gas Pneumatic Controls To Instrument Air Natural Gas Star Program 2006 https://www3.epa.gov/gasstar/documents/ll_instrument_air.pdf
[15]	CarbonLimits – expert opinion
[16]	Subpart W rulemaking and summary results https://www.law.cornell.edu/cfr/text/40/part-98/subpart-W/appendix-TableW-1A
[17]	Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Facilities – Background Technical Support Document for the Proposed New Source Performance Standards EPA, 2015 https://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2015-0216-0101
[18]	INITIAL ECONOMIC IMPACT ANALYSIS For proposed revisions to Colorado Air Quality Control Commission Regulation Number 7
[19]	Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector, EPA 2015 https://www3.epa.gov/airquality/oilandgas/pdfs/og_prop_ria_081815.pdf

6. Appendix

6.1 Quantitative assumptions for the model

Table 17: Quantative assumptions for the model

Description	Central Assumption	Unit	Source
GENERAL ASSUMPTIONS			
Gas price	2	\$/Mscf	[15]
Interest Rate	7%	%	NA
Share methane in the gas – Dry gas	0.0167	tCH_4/Mscf	[15]
Share of VOC in the gas – Dry gas	0.0046	tVOC/Mscf	[15]
Share methane in the gas – wet gas	0.0150	tCH_4/Mscf	[15]
Share of VOC in the gas – wet gas	0.0050	tVOC/Mscf	[15]
Remaining lifetime for retrofit	10	years	[15]
Remaining lifetime for new site	15	years	[15]
EMISSION FACTORS			
Continuous Controller (s)	14.43	cf/h	[2] (Company classification into EPA categories excluding ESD)
Intermittent Controller (s)	4.43	cf/h	[2] (Company classification into EPA categories excluding ESD)
Chemical Pumps	13.3	cf/h	[16]
ESD	0.41	cf/h	[2]
Continuous Controller (s)	1.39	cf/h	[16]
Intermittent Controller (s)	4.43	cf/h	[2]
Chemical Pumps	13.3	cf/h	NA
ESD	0.41	cf/h	[2]
INSTRUMENT AIR – ENGINEERING ASSUMPTIONS			
Share of the air bypassed in dryer	17%	%	[14,10]
Share of the utility air supply	200%	%	[14,10]
Sizing of compressor - variable component	0.2026	HP/cfm	[14,10]
Sizing of compressor - constant component	4.2356	HP	[14,10]
Load of the compressor (main)	50%	%	[14,10]
Sizing of the tank	6	gallon/cfm	[10]
Lifetime of the compressors	6	years	[10,14]
ELEC CONTROLLER - COST ASSUMPTIONS			
Continuous Controller (s) + control valve	4000	\$/unit	[9,10]
Intermittent Controller (s) + control valve	4000	\$/unit	[9,10]
Chemical injection pump	6000	\$/unit	[9,10]
Control Panel	4000	\$/unit	[9,10]
Solar Panel	500	\$/unit	[9,12]
Battery	400	\$/unit	[9,12]
Installation Costs	20%	of Equipment costs	[9,10]
Annual check up	80	\$/controller/year	[15]

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ELEC CONTROLLER - ENGINEERING ASSUMPTIONS			
Battery replacement frequency	4	years	[9,10]
Solar Panel replacement frequency	10	years	[9,10]
Continuous Controller (s)	0.08	Amps/unit	[9]
Chemical injection pumps	0.17	Amps/pump	[9]
ESD	0.16	Amps/unit	[9]
Other systems	0.29	Amps/site	[9]
System Voltage	12	V	[9,12]
Battery Average Efficiency	85%	%	[9,12]
Avg. Peak Sun	4	h/days	[9,10] (Confirmed with NREL)
Battery - At Maximum Depth of Discharge	80%	%	[9]
Days of Energy Storage	10	days	[9]
Rating of the solar panel	140	W	[9,12]
Rating of the battery	100	Ah	[9,12]
Oversizing of the solar panel	50%	%	[9,10]
INSTRUMENT AIR - COST ASSUMPTION			
Compressor Package – Main -5 HP	22000	$	[12,10]
Compressor Package – Main -10 HP	32000	$	[12,10]
Compressor Package – Main -15 HP	48000	$	[12,10]
Compressor Package – Main -20 HP	70000	$	[12,10]
Compressor - Unit cost - 5 HP	7000	$	[12]
Compressor - Unit cost - 10HP	10000	$	[12]
Compressor - Unit cost - 15 HP	15000	$	[12]
Compressor - Unit cost - 20 HP	23000	$	[12]
Other supply	1400	$/controller	[10]
Other supply	1000	$/controller	[10]
Installation	100%	%	[10]
Installation	50%	%	[10]
Compressor maintenance	4%	% of Capex	[10,15]
BASELINE - COST ASSUMPTION			
Continuous Controller (s) + control valve	2698	$/cont.	[17]
Intermittent Controller (s) + control valve	2471	$/cont.	[17]
Chemical injection Pump	1500	$/unit	[12]
Labor - installation - Controller	387	$/unit	[18]
Maintenance costs - Controller- wet gas sites	200	$/cont./year	[10]
Maintenance costs - Controller- dry gas sites	80	$/cont./year	[18]

6.2 Other assumptions for the model

- General assumptions

    - Retrofitting is assumed to be performed during a planned maintenance, hence retrofit activities do not cause production losses; thus, no potential revenue losses are accounted for in the estimates presented.
- Electronic controllers:
    - In all the site configurations, it is assumed that ESDs are gas driven pneumatic controllers.
    - Electronic controllers can reduce the need for site inspections. The subsequent reduced labour costs have not, however, been taken into consideration in the analysis. (conservative assumption)
- Instrument air
    - CO_2 emissions from power consumption (for non-solar powered options) have been neglected; this represents a very small volume of emissions compared to the CH_4 emissions (typically a few per cent, assuming a GWP of methane of 21).

6.3 Detailed sensitivity analysis

In the analysis presented, a number of assumptions have been made which affect the abatement cost. The following sections present the detailed sensitivity analysis performed.

Electronic controller – Retrofit
The following table presents a sensitivity analysis for the site configuration described in the section 4.2 (site with four controllers). The CH_4 abatement costs for a few key sensitivities should be compared to the abatement costs under the central assumption: \$751/t CH_4. The abatement cost under all the sensitivities is below the social cost of methane.

Table 18: Sensitivity analysis – retrofit site with 4 controllers– results

Name of the parameter	Central assumption	Sensitivity value	Abatement cost in \$/t CH_4
Number of pumps	0 pump	1 pump	614
Type of supply gas	Dry supply gas	Wet supply gas	702
Power on-site	No power on-site	Power on-site	611
Gas price	2 \$/Mscf	1 \$/Mscf	811
Gas price		3 \$/Mscf	692
Discount rate	7%	3%	635
Emission factors intermittent-vent cont.	4.43 scfh	8.6 scfh	522
		0.1 scfh	1267
Control Panel equipment cost	\$4000	\$6000	845
Installation Costs	20% of Equipment Costs	40% of Equipment Costs	889
Battery replacement freq.	4 years	2 years	823
Average peak sun	4 hours	2 hours	775

Electronic controller – New
The following table presents a sensitivity analysis for the site configuration described in the section 4.2 (site with four controllers). The CH_4 abatement cost for a few key sensitivities should be compared to the

abatement costs under the central assumption: \$847/t CH_4. The abatement costs for all the sensitivities are below the social cost of methane.

Table 19: Sensitivity analysis – New site with 4 controllers– results

Name of the parameter	Central assumption	Sensitivity value	Abatement cost in \$/t CH_4
Number of pumps	0 pump	1 pump	459
Type of supply gas	Dry supply gas	Wet supply gas	624
Power on-site	No power on-site	Power on-site	548
Gas price	2 \$/Mscf	1 \$/Mscf	906
Gas price		3 \$/Mscf	787
Discount rate	7%	3%	680
Emission factors low bleed controllers	1.39 scfh	6 scfh	547
		0.1 scfh	986
Control Panel equipment cost	\$4000	\$6000	1011
Installation Costs	20% of Equipment Costs	40% of Equipment Costs	1089
Battery replacement freq.	4 years	2 years	1046
Average peak sun	4 hours	2 hours	905
Low Bleed Cont. - Equipment cost	\$2698 per controller	\$554 per controller	993
Intermittent Cont. - Equipment cost	\$2471 per controller	\$387 per controller	1131

Instrument air – Retrofit

The following table presents a sensitivity analysis for the site configuration described in the section 4.3 (site with twenty controllers). The CH_4 abatement costs for a few key sensitivities should be compared to the abatement costs under the central assumption: \$972/t CH_4.

Table 20: Sensitivity analysis – retrofit site with 4 controllers– results

Name of the parameter	Central assumption	Sensitivity value	Abatement cost in \$/t CH_4
Type of supply gas	Dry supply gas	Wet supply gas	945
Gas price	2 \$/Mscf	1 \$/Mscf	1037
Gas price		3 \$/Mscf	908
Discount rate	7%	3%	848
Emission factors intermittent-vent cont.	4.43 scfh	8.6 scfh	679
		0.1 scfh	1656
Other supplies costs	\$1400/controller	\$1800 /controller	1100
		\$1000 /controller	844
Electrical, mechanical & civil installation costs	100% of equipment and supplies costs	150% of equipment and supplies costs	1212
		50% of equipment and supplies costs	732

Instrument air – New site

The following table presents a sensitivity analysis for the site configuration described in the section 4.3 (site with twenty controllers). The CH_4 abatement costs for a few key sensitivities should be compared to the abatement costs under the central assumption: $886/t CH_4.

Table 21: Sensitivity analysis – retrofit site with 4 controllers– results

Name of the parameter	Central assumption	Sensitivity value	Abatement cost in $/t CH_4
Type of supply gas	Dry supply gas	Wet supply gas	690
Gas price	2 $/Mscf	1 $/Mscf	949
Gas price		3 $/Mscf	824
Discount rate	7%	3%	734
Other supplies costs	$1000/controller	$1200 /controller	963
Electrical, mechanical & civil installation costs	50% of equipment and supplies costs	100% of equipment and supplies costs	1154
Emission factors low bleed controllers	1.39 scfh	6 scfh	800
		0.1 scfh	1011

6.4 List of site configurations with abatement cost superior to the social cost of methane

The following table presents a complete list of all the site configurations with an abatement cost higher than the social cost of methane.

Electronic controller – New sites

The abatement cost is presented for the central assumptions, but also (right column) for a low-bleed emission factor of 5 scfh (compared to 1.39 in the central assumption).

Table 22: Site configurations with abatement cost superior to $1354/ton - Electric controller – New sites

Site configuration ID	New/ retrofit	Electricity on site?	Supply gas	Pump #	Continuous Cont. #	Intermittent Cont. #	ESD #	Abatement costs – central assumptions	Abatement costs – Higher EF assumption
13	New	Electricity	Wet	0	1	0	1	1985	456
349	New	Electricity	Dry	0	1	0	1	2838	703
355	New	Electricity	Dry	0	2	0	1	1793	412
361	New	Electricity	Dry	0	3	0	1	1445	315
685	New	No electricity	Wet	0	1	0	1	3777	954
691	New	No electricity	Wet	0	2	0	1	2009	462
697	New	No electricity	Wet	0	3	0	1	1643	361
1021	New	No electricity	Dry	0	1	0	1	4446	1150
1027	New	No electricity	Dry	0	2	0	1	2595	635
1033	New	No electricity	Dry	0	3	0	1	2179	520
1039	New	No electricity	Dry	0	4	0	1	1820	420
1045	New	No electricity	Dry	0	5	0	1	1605	360

Electronic controller – Retrofit sites

The abatement cost is presented for the central assumptions, but also (right column) for an intermittent-vent controller emission factor of 7 scfh (compared to 4.43 in the central assumption).

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Table 23: Site configurations with abatement cost superior to $1354/ton - Electric controller – Retrofit

Site configuration ID	New/ retrofit	Electricity on site?	Supply gas	Pump #	Continuous Cont. #	Intermittent Cont. #	ESD #	Abatement costs – central assumptions	Abatement costs – Higher EF assumption
1345	Retrofit	Electricity	Wet	0	0	1	1	1593	960
1681	Retrofit	Electricity	Dry	0	0	1	1	1750	1064
2017	Retrofit	No electricity	Dry	0	0	1	1	2282	1400
2018	Retrofit	No electricity	Dry	0	0	2	1	1573	952
2019	Retrofit	No electricity	Dry	0	0	3	1	1406	846
2353	Retrofit	No electricity	Wet	0	0	1	1	2186	1335
2354	Retrofit	No electricity	Wet	0	0	2	1	1486	891

Instrument air – Retrofit sites

The abatement cost is presented for the central assumptions, but also (right column) for a low-bleed emission factor of 5 scfh (compared to 1.39 in the central assumption).

Table 24: Site configurations with abatement cost superior to $1354/ton – Instrument air – Retrofit

Site configuration ID	New/ retrofit	Electricity on site?	Supply gas	Pump #	Continuous Cont. #	Intermittent Cont. #	ESD #	Abatement costs – central assumptions	Abatement costs – Higher EF assumption
437	New	Electricity	Dry	0	20	1	5	1651	612
438	New	Electricity	Dry	0	20	2	5	1466	589
447	New	Electricity	Dry	0	25	0	5	1595	515
448	New	Electricity	Dry	0	25	1	6	1426	501
457	New	Electricity	Dry	0	30	0	6	1392	436

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CLEAN AIR ADVOCATES' EXHIBIT 5

Conservation Groups' Initial Economic Impact Analysis
Non-Emitting Pneumatics - 2020

Natural Gas Compressor Stations Non-Emitting Pneumatic Controllers

Sierra Club and Earthworks (collectively, "Conservation Groups") propose to strengthen the Division's proposal for pneumatic controllers by requiring the elimination of venting of natural gas from all pneumatic controllers at compressor stations. As we show below, non-emitting controllers are cost-effective at the average compressor station, which has 9 intermittent-bleed pneumatic controllers and 1 continuous-bleed pneumatic controllers.

Based on the Division's EIA for the 2019 revisions to Regulation 7, we estimate that there are 188 gathering and boosting compressor stations outside the nonattainment area ("rest of state" or "ROS").[1] In the Nonattainment Area ("NAA"), the Division recently estimated that there are 58 gathering and boosting compressor stations, but the Division found that by summer 2018, at least 48 of them had been converted, or were in the process of being converted, to non-emitting controllers.[2] Therefore, we calculate the benefits and costs for converting the balance of NAA gathering and boosting compressor stations – 10 stations – to non-emitting controllers.

The costs of converting to non-emitting controllers varies depending on a number of characteristics. We calculate costs using the Pneumatics Cost Tool developed by Carbon Limits.[3] Among other things, the cost depends upon the number of controllers of each type at the facility. Based on the U.S. Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program (GHGRP) data about pneumatic controller counts at compressor stations and the number of compressor stations reported by CDPHE in the ROS, Conservation Groups estimate that there are an average of 9 intermittent bleed pneumatic controllers and 1 continuous bleed pneumatic controllers per compressor station.[4] We used those figures, conservative emissions factors for pneumatic controllers,[5] and values for the price of conserved gas and the VOC and methane-ethane content of gas consistent with those used by the Division.[6] Using these parameters, we calculated the following abatement tonnages and costs for retrofitting a compressor station which does not have electricity available on-site (this is conservative, since some stations will have sufficient electricity to operate zero-emitting controllers available).

[1] CDPHE Air Pollution Control Division, Regulation Number 7 Economic Impact Analysis, (November 5, 2019), table 24.
[2] Colo. Air Pollution Control Div., *Pneumatic Controller Task Force Report to the Air Quality Control Commission* at 10 (June 1, 2020) (SC&E_ALT_EX-001).
[3] Carbon Limits, Zero Bleed Pneumatic Cost Spreadsheet Tool (Aug. 1, 2016) (SC&E_ALT_EX-002).
[4] *See* Appendix.
[5] 3.5 scfh for intermittent-bleed controllers; 5.1 scfh for continuous-bleed controllers. *See* David McCabe, et al., Memorandum: *Average Emissions from Intermittent-Vent Pneumatic Controllers as Reported by Allen*, et al. (2015) (SC&E_ALT_EX-003).
[6] Value of conserved gas: $1.87 / Mcf (average Henry Hub price Jan – Sept 2020). Gas composition (wet gas): 5.77 kg VOC/Mscf in the NAA and 4.80 kg VOC/Mscf in the ROS; 15.4 kg CH_4/Mscf in the NAA and 16.3 kg CH_4/Mscf in the ROS. Calculated from 24.4 weight % VOC for the NAA and 20.3 weight % VOC for ROS, based on Division model data from 2017 for VOC content of leaking gas in those areas.

Table 1: Costs of non-emitting conversion at average compressor station in NAA and ROS

	Number of Compressor Stations	Intermittent Controllers On-site	Continuous Controllers On-site	Equipment Cost	Install Cost	Net Ongoing cost[7]	Value of Saved Gas	Annual Cost per Station	Total Annual Cost
NAA	10	9	1	$46,100	$9,220	-$847	$600	$3,883	$38,834
ROS	188	9	1	$46,100	$9,220	-$847	$600	$3,883	$38,834

Table 2: Reductions (in tons per year) and abatement cost of non-emitting conversion at average compressor station in NAA and ROS

	VOC savings per comp. station	Methane-ethane savings per CS	Total VOC Savings in area	VOC Abatement Cost ($/short ton)	Total Methane-Ethane Savings in area	Methane-ethane Abatement Cost ($/short ton)[8]
NAA	2.0	6.3	20	$1,904	63	$615
ROS	1.7	6.7	319	$2,289	1,257	$581

Abatement costs per ton of pollutant will be lower at larger compressor stations with more pneumatic equipment.

Well Production Facilities Zero Bleed Pneumatic Equipment

Conservation Groups propose to strengthen the Division's proposal for pneumatic controllers by requiring the elimination of venting of natural gas from all pneumatic controllers at larger well production facilities. As we show below, non-emitting controllers are cost-effective at well pads with 4 or more wells in both the NAA and the ROS.

Strengthen to require non-emitting pneumatic controllers at well production facilities with 4 or more wells in the NAA

We calculated that the average annualized cost of our proposal in the NAA is $7,793 per pad, and the average VOC abatement cost is $1,534/short ton.

The costs of converting to non-emitting pneumatic controllers varies depending on a number of characteristics. We calculate costs using the Pneumatics Cost Tool developed by Carbon Limits.[9] Among other things, the cost depends upon the number of controllers of each type and pumps at the facility. For wellpads, the number of controllers and pumps will generally vary with the number of wells. We used data from the GHGRP to estimate the number of pneumatic controllers and pumps per well in NAA.[10] We found that there are 2.44 intermittent-bleed

[7] Ongoing cost of zero bleed system minus cost of maintaining natural gas-powered system with wet gas.
[8] To convert from methane to methane-ethane we assume gas is 65.7% methane and 10.6% ethane. *See* Memorandum from Heather P. Brown, P.E. to Bruce Moore, EPA/OAQPS/SPPD re: Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking (July 28, 2011), https://beta.regulations.gov/document/EPA-HQ-OAR-2010-0505-4908 (SC&E_ALT_EX-004).
[9] Carbon Limits, Zero Bleed Pneumatic Cost Spreadsheet Tool, *supra* n.3.
[10] *See* Appendix.

pneumatic controllers and 0.68 continuous-bleed controllers per well, and 0.017 pneumatic pumps. We used these factors to estimate the number of controllers per pad for pads with various numbers of wells.

We then analyzed oil and gas well data from the Colorado Oil and Gas Conservation Commission ("COGCC") to determine the number of well pads at various sizes in the NAA.[11] Based on this analysis, we found that there are 10,552 wells in the NAA, on 4,403 pads. 6,029 (57%) of these wells are on 796 pads with four or more wells, but these 796 pads represent only 18% of pads in the NAA.

Since the cost of non-emitting equipment varies with the number of controllers – and therefore wells – at a facility, we calculated the costs for each size wellpad, and then calculate overall cost using the figures for each size. Average costs are weighted by the number of pads of each size.

We used conservative emissions factors for pneumatic controllers based on measurements in the peer-reviewed literature,[12] values for the VOC and methane-ethane content of gas consistent with those used by the Division,[13] and a value for the price of conserved gas calculated using the Division's methodology.[14] Using these parameters, we calculated the abatement tonnages and costs for retrofitting wellpads in the NAA displayed in Tables 3 and 4 below.

For wellpads with less than 30 controllers, we present cost calculations calculated for the installation of electric controllers powered by solar panels (as opposed to calculating the cost of installing an instrument air system, for example). Due to limitations in the Carbon Limits cost tool used to calculate costs for replacing pneumatic equipment, we are unable to provide specific cost or cost-effectiveness estimates for wellpads with more than 30 controllers at this time. Therefore, the cost and cost-effectiveness numbers for those wellpads are not shown in Tables 3 and 4 below.

However, there is a clear trend of improving cost-effectiveness (decreasing cost per ton of avoided pollutants) as the number of wells/controllers increases, as seen in Table 4. This arises because non-emitting solutions such as solar-powered electric controllers entail significant common equipment used for all the controllers on the pad, such as solar panels, batteries, and control panels. As more controllers share the use of the centralized equipment, the cost per ton of avoided pollution drops. Therefore, we are confident that the overall cost-effectiveness figure we calculate (based on pads with fewer than 30 controllers) is a conservative estimate of overall program cost-effectiveness. Additionally, we note that we are providing specific cost effectiveness data for 616 of the 796 estimated wellpads (77%) covered by our Alternative Proposal in the NAA.

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[11] We downloaded data from COGCC's website, http://cogcc.state.co.us/documents/data/downloads/gis/WELLS_SHP.ZIP. We then exported Shapefile data for analysis. We sorted wells into NAA and ROS based on county, and location for wells in Larimer and Weld counties and included only "producing" wells. We then sorted wells into pads using the parameter "Loc_ID."

[12] 3.5 scfh for intermittent-bleed controllers; 5.1 scfh for continuous-bleed controllers. *See* McCabe et al., *supra* n.5.

[13] Gas composition (wet gas): 5.77 kg VOC/Mscf in the NAA; 15.4 kg CH_4/Mscf in the NAA. Calculated from 24.4 weight % VOC for the NAA, based on Division model data for VOC content of leaking gas in the NAA.

[14] Value of conserved gas: $1.87 / Mcf (average Henry Hub price Jan – Sept 2020).

Table 3: Costs of non-emitting conversion at various well sizes in NAA

Wells per Pad	# pads	# wells	Cont Controllers On-site	Int. Controllers On-site	Equip. Cost	Install Cost	Net Ongoing cost[15]	Value of Saved Gas	Annualized Cost per Pad	Total Annualized Cost in NAA
4	211	844	3	10	$58,600	$11,720	-$1,173	$824	$4,777	$1,008,049
5	109	545	3	12	$67,000	$13,400	-$1,333	$939	$5,474	$596,660
6	95	570	4	15	$83,400	$16,680	-$1,733	$1,194	$6,714	$637,869
7	77	539	5	17	$95,800	$19,160	-$2,013	$1,392	$7,670	$590,573
8	93	744	5	20	$108,300	$21,660	-$2,340	$1,564	$8,616	$801,310
9	31	279	6	22	$120,700	$24,140	-$2,620	$1,763	$9,572	$296,720
10	35	350	7	24	--	--	--	--	--	--
11	33	363	7	27	--	--	--	--	--	--
12	34	408	8	29	--	--	--	--	--	--
13	17	221	9	32	--	--	--	--	--	--
14	6	84	10	34	--	--	--	--	--	--
15	7	105	10	37	--	--	--	--	--	--
16	6	96	11	39	--	--	--	--	--	--
17	3	51	12	42	--	--	--	--	--	--
18	8	144	12	44	--	--	--	--	--	--
19	6	114	13	46	--	--	--	--	--	--
20	9	180	14	49	--	--	--	--	--	--
21	4	84	14	51	--	--	--	--	--	--
22	2	44	15	54	--	--	--	--	--	--
23	1	23	16	56	--	--	--	--	--	--
24	3	72	16	59	--	--	--	--	--	--
25	2	50	17	61	--	--	--	--	--	--
27	2	54	18	66	--	--	--	--	--	--
29	1	29	20	71	--	--	--	--	--	--
36	1	36	24	88	--	--	--	--	--	--
Totals for all covered pads (4-36 wells per pad):										
	796	6,029								
Cost averages for pads with 4-9 wells per pad:										
					$79,189	$15,838	-$1,642	$1,131	$6,382	$3,931,180

Table 4: Reductions (in tons per year) and abatement cost of non-emitting conversion at various well sizes in NAA

Wells per Pad	VOC savings per pad	Methane-ethane savings per pad	Total VOC Savings in NAA	VOC Abatement Cost ($/short ton)	Total Methane-Ethane Savings in NAA	Methane-ethane Abatement Cost ($/short ton)[16]
4	2.8	8.7	591	$1,705	1,832	$550
5	3.2	9.9	348	$1,715	1,078	$553
6	4.1	12.6	386	$1,653	1,196	$533
7	4.7	14.7	365	$1,619	1,130	$523
8	5.3	16.5	495	$1,619	1,533	$523
9	6.0	18.6	186	$1,597	576	$515
10	6.7	20.7	233	--	723	--
11	7.3	22.5	239	--	742	--
12	7.9	24.6	270	--	835	--
13	8.8	27.3	150	--	463	--

[15] Ongoing cost of zero bleed system minus cost of maintaining natural gas-powered system with wet gas.
[16] To convert from methane to methane-ethane we assume gas is 65.7% methane and 10.6% ethane by weight. *See* Memorandum from Heather P. Brown, *supra* n.8.

14	9.5	29.4	57	--	176	--
15	10.1	31.2	70	--	218	--
16	10.7	33.3	64	--	200	--
17	11.6	35.9	35	--	108	--
18	12.0	37.2	96	--	297	--
19	12.7	39.2	76	--	235	--
20	13.5	41.9	122	--	377	--
21	13.9	43.1	56	--	173	--
22	14.8	45.8	30	--	92	--
23	15.5	47.9	15	--	48	--
24	16.1	49.7	48	--	149	--
25	16.7	51.8	33	--	104	--
27	18.0	55.7	36	--	111	--
29	19.5	60.5	20	--	61	--
36	24.0	74.3	24	--	74	--
Totals/averages for all covered pads (4-36 wells per pad):						
	5.08	15.74	4,044		12,532	
Average cost-effectiveness for pads with 4-9 wells per pad:						
				$1,658		$535

Strengthen to require non-emitting pneumatic controllers at well production facilities with 4 or more wells in the ROS

We calculated that the average annualized cost of our proposal in the ROS is $8,256 per pad, and the average VOC abatement cost is $1,935/short ton. This calculation is directly analogous to the calculations described in the previous section for the NAA. The only differences are in the amount of pneumatic equipment per well, the VOC and methane-ethane content of the gas, and the distribution of wellpad sizes.[17] We used data from the GHGRP to estimate the number of pneumatic controllers and pumps per well outside the NAA.[18] We found that there are 2.5 intermittent-bleed pneumatic controllers per well, 0.23 continuous-bleed pneumatic controllers per well, and 0.64 pneumatic pumps per well.

As with the NAA, we analyzed oil and gas well data from COGCC to determine the number of wellpads at various sizes in the ROS.[19] Based on this analysis, we found that there are 25,412 wells on 13,757 pads. 11,220 (44%) of these wells are on 1,219 pads with four or more wells, but these 1,219 pads represent only 9% of pads in the ROS.

As with the NAA, since the cost of non-emitting equipment varies with the number of controllers – and therefore wells – at a facility, we calculated the costs for each size wellpad, and then calculate overall cost using the figures for each size. Average costs are weighted by the number of pads of each size.

As with the NAA, we used conservative emissions factors for pneumatic controllers based on measurements in the peer-reviewed literature,[20] values for the VOC and methane-ethane content

[17] *See* Appendix for discussion of equipment per well.
[18] *See* Appendix.
[19] *See supra* n.11.
[20] 3.5 scfh for intermittent-bleed controllers; 5.1 scfh for continuous-bleed controllers. *See* McCabe et al., *supra* n.5.

of gas consistent with those used by the Division,[21] and a value for the price of conserved gas calculated using the Division's methodology.[22] Using these parameters, we calculated the abatement tonnages and costs for retrofitting wellpads in the ROS displayed on Tables 5 and 6 below.

For wellpads with less than 30 controllers, we present cost calculations calculated for the installation of electric controllers powered by solar panels (as opposed to calculating the cost of installing an instrument air system, for example). Due to limitations in the Carbon Limits cost tool used to calculate costs for replacing pneumatic equipment, we are unable to provide specific cost or cost-effectiveness estimates for wellpads with more than 30 controllers at this time. Therefore, the cost and cost-effectiveness numbers for those wellpads are not shown in Tables 5 and 6 below.

However, there is a clear trend of improving cost-effectiveness (decreasing cost per ton of avoided pollutants) as the number of wells/controllers increases, as seen in Table 6. This arises because non-emitting solutions such as solar-powered electric controllers entail significant common equipment used for all the controllers on the pad, such as solar panels, batteries, and control panels. As more controllers share the use of the centralized equipment, the cost per ton of avoided pollution drops. Therefore, we are confident that the overall cost-effectiveness figure we calculate (based on pads with fewer than 30 controllers) is a conservative estimate of overall program cost-effectiveness. Additionally, we note that we are providing specific cost effectiveness data for 862 of the 1,219 estimated wellpads (71%) covered by our Alternative Proposal in the ROS.

Table 5: Costs of non-emitting conversion at various well sizes in ROS

Wells per Pad	# pads	# wells	Int. Cont. On-site	Cont. Cont. On-Site	Equip. Cost	Install Cost	Net Ongoing cost[23]	Value of Saved Gas	Annual. Cost per Pad	Total Annual. Cost in ROS
4	269	1,076	1	10	$50,600	$10,120	-$933	$657	$4,260	$1,145,855
5	172	860	1	13	$63,000	$12,600	-$1,213	$829	$5,241	$901,496
6	118	708	1	15	$71,000	$14,200	-$1,453	$944	$5,811	$685,754
7	82	574	2	18	$87,400	$17,480	-$1,853	$1,199	$7,052	$578,259
8	105	840	2	20	$95,800	$19,160	-$2,013	$1,314	$7,748	$813,582
9	64	576	2	23	$108,300	$21,660	-$2,340	$1,486	$8,695	$556,472
10	52	520	2	25	$116,700	$23,340	-$2,500	$1,600	$9,391	$488,349
11	33	363	3	28	--	--	--	--	--	--
12	41	492	3	30	--	--	--	--	--	--
13	33	429	3	33	--	--	--	--	--	--
14	31	434	3	35	--	--	--	--	--	--
15	33	495	3	38	--	--	--	--	--	--
16	48	768	4	40	--	--	--	--	--	--
17	18	306	4	43	--	--	--	--	--	--
18	18	324	4	45	--	--	--	--	--	--
19	11	209	4	48	--	--	--	--	--	--
20	17	340	5	50	--	--	--	--	--	--
21	11	231	5	53	--	--	--	--	--	--

[21] Gas composition (wet gas): 4.80 kg VOC/Mscf in the ROS; 16.3 kg CH_4/Mscf in the ROS. Calculated from 20.3 weight % VOC for ROS, based on Division model data for VOC content of leaking gas in the ROS.
[22] $1.87 / Mcf. *See supra* n.14.
[23] Ongoing cost of zero bleed system minus cost of maintaining natural gas-powered system with wet gas.

22	13	286	5	55	--	--	--	--	--	--
23	7	161	5	58	--	--	--	--	--	--
24	13	312	6	60	--	--	--	--	--	--
25	2	50	6	63	--	--	--	--	--	--
26	2	52	6	65	--	--	--	--	--	--
27	2	54	6	68	--	--	--	--	--	--
28	7	196	6	70	--	--	--	--	--	--
29	3	87	7	73	--	--	--	--	--	--
30	3	90	7	75	--	--	--	--	--	--
31	4	124	7	78	--	--	--	--	--	--
32	2	64	7	80	--	--	--	--	--	--
33	1	33	8	83	--	--	--	--	--	--
34	1	34	8	85	--	--	--	--	--	--
40	1	40	9	101	--	--	--	--	--	--
41	1	41	9	103	--	--	--	--	--	--
51	1	51	12	128	--	--	--	--	--	--
Totals for all covered pads (4-51 wells per pad):										
	1,219	11,220								
Cost averages for pads with 4-10 wells per pad:										
					$73,145	$14,629	-$1,478	$981	$5,997	$5,169,767

Table 6: Reductions (in tons per year) and abatement cost of non-emitting conversion at various well sizes in ROS

Wells per Pad	VOC savings per pad	Methane-ethane savings per pad	Total VOC Savings in ROS	VOC Abatement Cost ($/short ton)	Total Methane-Ethane Savings in ROS	Methane-ethane Abatement Cost ($/short ton)[24]
4	1.9	7.3	500	$2,292	1,971	$581
5	2.3	9.2	403	$2,235	1,590	$567
6	2.7	10.5	315	$2,177	1,242	$552
7	3.4	13.4	278	$2,078	1,097	$527
8	3.7	14.7	390	$2,084	1,539	$529
9	4.2	16.6	269	$2,068	1,061	$525
10	4.5	17.9	235	$2,074	928	$526
11	5.3	20.7	173	--	683	--
12	5.6	22.0	229	--	901	--
13	6.1	23.9	200	--	789	--
14	6.4	25.2	198	--	781	--
15	6.9	27.1	227	--	894	--
16	7.4	29.3	357	--	1,407	--
17	7.9	31.2	143	--	562	--
18	8.2	32.5	148	--	585	--
19	8.7	34.4	96	--	379	--
20	9.3	36.6	158	--	623	--
21	9.8	38.6	108	--	424	--
22	10.1	39.8	131	--	518	--
23	10.6	41.8	74	--	292	--
24	11.2	44.0	145	--	572	--
25	11.6	45.9	23	--	92	--
26	12.0	47.2	24	--	94	--
27	12.4	49.1	25	--	98	--
28	12.8	50.4	89	--	353	--
29	13.5	53.2	40	--	160	--
30	13.8	54.5	41	--	163	--

[24] To convert from methane to methane-ethane we assume gas is 65.7% methane and 10.6% ethane by weight. *See* Memorandum from Heather P. Brown, *supra* n.8 at tbl. 5.

31	14.3	56.4	57	--	226	--
32	14.6	57.7	29	--	115	--
33	15.4	60.5	15	--	61	--
34	15.7	61.8	16	--	62	--
40	18.5	73.0	19	--	73	--
41	18.8	74.3	19	--	74	--
51	23.6	93.0	24	--	93	--
Totals/averages for all covered pads (4-51 wells per pad):						
	4.27	16.82	5,200		20,502	
Average cost-effectiveness for pads with 4-10 wells per pad:						
				$2,162		$548

Extend requirement for non-emitting pneumatic controllers at new/modified well production facilities in the NAA and ROS

We calculated the costs of requiring non-emitting pneumatic controllers at new/modified wellpads with 2 and 3 wells in the NAA and ROS using the same assumptions about pneumatic controllers per well, gas composition, and gas price as in analysis above. The only change in calculating costs using the Zero-Bleed Pneumatics tool for these "modified" sites was to use the "New Site" option rather than "retrofit". We do not present the cost results for wellpads with 4 or more wells; Tables 3 and 5 show that retrofit with non-emitting controllers at these sites is cost-effective, and costs for new sites are always lower than costs for retrofits.

Table 7: Costs of non-emitting conversion for new/modified sites in ROS and NAA

NAA or ROS	Wells per Pad	Int. Cont. On-site	Cont. Cont. On-Site	Equip. Cost	Install Cost	Net Ongoing cost[25]	Value of Saved Gas	Annual. Cost per Pad
NAA	2	5	1	$14,647	$3,618	-$447	$370	$943
NAA	3	7	2	$19,407	$4,937	-$727	$568	$1,050
ROS	2	5	0	$13,345	$3,205	-$327	$287	$981
ROS	3	8	1	$19,634	$4,937	-$727	$542	$1,098

Table 8: Reductions (tons per year) and abatement cost of non-emitting conversion for new/modified sites in ROS and NAA

NAA or ROS	Wells per Pad	VOC savings per pad	Methane-ethane savings per pad	VOC Abatement Cost ($/short ton)	Methane-ethane Abatement Cost ($/short ton)[26]
NAA	2	1.3	3.9	$749	$242
NAA	3	1.9	6.0	$543	$175
ROS	2	0.8	3.2	$1,210	$307
ROS	3	1.5	6.0	$716	$182

[25] Ongoing cost of zero bleed system minus cost of maintaining natural gas-powered system with wet gas.

[26] To convert from methane to methane-ethane we assume gas is 65.7% methane and 10.6% ethane by weight. *See* Memorandum from Heather P. Brown, *supra* n.8 at tbl. 5.

Appendix

We estimate the number of pneumatic controllers and pumps in Colorado using the percent of gas production and the percent of wells in each basin that are in Colorado.[27]

	Total # of Wells in Basin	Percent of Wells in Colorado	# Wells in Colorado
Anadarko Basin	38,005	0.01%	3
Las Vegas-Raton Basin	2,276	100%	2,276
Green River Basin	11,394	1.86%	212
Denver Basin	17,849	98.92%	17,657
Piceance Basin	13,182	100%	13,182
North Park Basin	36	100%	36
Paradox Basin	486	14.4%	70

The nonattainment area accounts for most but not all of the Denver basin, so we estimated the percent of the Denver Basin that is part of the NAA. We conducted a GIS analysis of producing wells in the Denver Basin to determine what percentage of active wells in each basin were located within the NAA.[28] Then we applied these percentages to the well count in the 2018 GHGRP. We estimate that 81% of the Colorado wells in the Denver Basin are located in the NAA.

County	Wells	% in NAA	# in NAA	
Adams	229	100%	229	
Arapahoe	65	100%	65	
Boulder	258	100%	258	
Broomfield	66	100%	66	
Elbert	5	0%	-	
Larimer	68	80%	54	
Logan	2	0%	-	
Morgan	3	8%	0	
Philips	1	0%	-	
Washington	6	0%	-	
Weld	14,577	94%	13,702	
Yuma	2,377	0%	-	
	17,657		14,375	**81%**

Gathering and Boosting Compressor Station Pneumatic Devices

We used data from the EPA GHG Reporting Program (GHGRP) to estimate the number of pneumatic controllers and pumps at gathering and boosting compressor stations in the rest of the state. Following guidance from the CDPHE, in this analysis we excluded facilities in the San Juan Basin, because the majority of those are on tribal land. Companies report total number of pneumatic controllers at the basin level. There are 7 basins that include part of Colorado (excluding the San Juan).[29]

[27] EPA GHGRP. Table: EF_W_ONSHORE_WELLS (producing wells only).
[28] COGCC, GIS, Well Surface Location Data, Well Spots. Accessed October 2020. Available at: https://cogcc.state.co.us/data2.html#/downloads.
[29] EPA GHGRP. Table: EF_W_NGPNEUMATIC_DEV_UNITS and EF_W_NGPNEUMATIC_PMP_UNITS.

Basin	High-bleed Pneumatic Devices*	Intermittent Bleed Pneumatic Devices	Low-Bleed Pneumatic Devices	Total Pneumatic Controllers	Pneumatic Pumps
Anadarko Basin	1,054	8,044	5,223	14,321	2,068
Las Vegas-Raton Basin		314		314	12
Green River Basin	173	991	58	1,222	150
Denver Basin	0	7,016	1,137	8,153	112
Piceance Basin	7	365	112	484	45
North Park Basin		69		69	
Paradox Basin					
Total	**1,234**	**16,799**	**6,530**	**24,563**	**2,387**

Using the distribution of wells by basin in and out of Colorado (and assuming that the number of gathering and boosting compressor stations is proportional to the number of wells), we calculate the total number of controllers and pumps in the ROS. There are 188 gathering and boosting compressor stations in the ROS,[30] so we use this to estimate the average number of controllers and pumps per station.

	ROS
Intermittent Bleed Pneumatic Devices	1,745
Low-Bleed Pneumatic Devices	227
Pumps	42
Compressor Stations	188
Intermittent Bleed Pneumatic Devices per station	9
Low-Bleed Pneumatic Devices per station	1
Pumps per station	0.2

This approach does not produce credible results for the NAA. This is likely due to the fact that the conversion of gathering and boosting compressor stations to non-emitting controllers noted above[31] was underway in the most recent years for which GHGRP data is available, making those data inaccurate. Therefore, we assume that the number of controllers per station is the same in ROS and NAA.

Well Production Facility Pneumatic Devices

We used data from the EPA GHG Reporting Program (GHGRP) to estimate the number of pneumatic controllers and pumps at well production facilities in the nonattainment area and in the rest of the state. Following guidance from the CDPHE, in this analysis we excluded wells in the San Juan Basin, because the majority of those are on tribal land. Companies report total number of pneumatic controllers and pumps at the basin level. There are 7 basins that include part of Colorado (excluding the San Juan).[32]

Basin	High-bleed Pneumatic Devices*	Intermittent Bleed Pneumatic Devices	Low-Bleed Pneumatic Devices	Total Pneumatic Controllers	Pneumatic Pumps
Anadarko Basin	8,470	67,311	15,691	91,472	10,839
Las Vegas-Raton Basin		260		260	
Green River Basin	98	41,344	6,762	48,204	7,287
Denver Basin		43,624	12,137	55,761	200

[30] *Supra* n.1.
[31] *Supra* n.2.
[32] EPA GHGRP. Table: EF_W_NGPNEUMATIC_DEV_UNITS and EF_W_NGPNEUMATIC_PMP_UNITS.

Piceance Basin		38,637	2,065	40,702	992
North Park Basin		65		65	
Paradox Basin		266		266	20
Total	**8,568**	**191,176**	**36,655**	**236,399**	**21,705**

*We assume that the High-bleed pneumatic controllers found in Anadarko and Green River Basins are outside of Colorado and exclude them from this analysis.

Using the above data on pneumatic pumps and controllers per basin, and the details of the percent of the basins in/out of Colorado and in/out of the NAA within the Denver Basin, we arrive at the following estimates of pneumatic controllers and pumps per well.

Controllers per Well	NAA	ROS
Intermittent Bleed Pneumatic Devices	35,133	47,796
Low-Bleed Pneumatic Devices	9,775	4,424
Wells	14,375	19,061
Intermittent per well	2.44	2.51
Low per well	0.68	0.23

Pumps per well	NAA	ROS
Pumps	161	1,168
Wells	14,375	19,061
Pumps per well	0.011	0.061

Because pumps per well in both NAA and ROS are so small, we do not include these in calculates of zero bleed pneumatic costs.

CLEAN AIR ADVOCATES' EXHIBIT 6

[Pneumatics Cost Spreadsheet, Carbon Limits, attached separately as Excel spreadsheet]

CLEAN AIR ADVOCATES' EXHIBIT 7

Cap-Op Energy British Columbia Oil and Gas Methane Emissions Field Study

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Executive Summary

The British Columbia Methane Emissions Field Study was undertaken in order to inform the modeling parameters used in time-series methane emission modeling. An advisory team comprising the British Columbia Ministry of Environment and Climate Change Strategy – Climate Action Secretariat (BC CAS), the British Columbia Oil and Gas Commission (BC OGC), Environment and Climate Change Canada (ECCC), and the Ministry of Energy, Mines and Petroleum Resources (MEMPR) was established in order to engage directly with the project team comprising Cap-Op Energy, Greenpath Energy, DXD Consulting and Dr. Arvind Ravikumar. BC OGC inspectors also contributed to the data collection.

Scope of Field Survey	
Total Sites Visited	266
Production/Facility Types Represented	12
Total Quantifiable Methane Emission Sources (#, volume)[1]	1,000 sources, 362 m^3/hour

The study gathered a broad spectrum of methane emissions data at 266 locations (wells and batteries) across British Columbia, encompassing fugitive emissions, equipment venting emissions, pneumatic inventory and emissions estimates, as well as episodic and other sources of methane emissions. The data were compiled and analyzed to characterize British Columbia's oil and gas operations from a methane emissions perspective. In order to align with current and projected production centres, coverage of tight wells and batteries in the Montney was prioritized. The collection of sites

[1] Some sources were quantified using visual estimation (e.g. inaccessible fugitives), or factors (e.g. pneumatic control instruments). Methane content of sources was not determined.

sampled was determined to be representative of the available population, based on recent production rates – both within each production/facility type category as well as overall.

Analysis of field survey results identified key similarities as well as key differences between British Columbia and other jurisdictions.

The findings from the field survey aligned with other similar studies where a small number of sources were found to be responsible for a large portion of the methane releases.[3] Specifically, 51% of emissions resulted from the top 8.7% of equipment fugitives. Excluding pneumatic venting, 43% (114 of 266) of visited sites had no venting or fugitives detected.

Methane emissions from natural gas-driven pneumatic devices (67% of total) represent significant sources methane emissions at BC wells and batteries. Non-emitting control instruments and chemical injection pumps (e.g. solar electric or air-driven) were observed to be very common in BC. Of all pneumatic or pneumatic-equivalent devices observed in the study, 65% were non-emitting; a recent pneumatic inventory in Alberta found <5% non-emitting.

Summary of Field Survey Findings

Total Leak-free and Vent-free Sites[2] Surveyed	114 (43%)
Total Natural Gas-Driven Pneumatic Devices	725 (34%) (242 m^3/hour est.)
Venting Emissions	101 (63 m^3/hour)
Equipment Fugitive Emissions	284 (57 m^3/hour)

Tanks contributed a significant proportion of total emissions (12% including vents and leaks). Tanks were responsible for 65% of total non-pneumatic venting emissions (2 other equipment types, Reciprocating Compressor and Surface Casing Vents, combined with tanks represent 94% of overall non-pneumatic venting emissions). This includes hydrocarbon venting from Produced Water Tanks (25% of total tank venting).[4] Thief Hatches, a tank-specific component, also have the highest average, median, and site level leak rates which suggests that Thief Hatches are currently responsible for a significant portion of methane leak emissions (3% of overall leak sources, 17% of overall leak emissions).

While compressor stations were not a specific focus of the study, 69 compressors units were observed at batteries. These were catalogued and found to exhibit average emission rates consistent with population-wide figures from the US Greenhouse Gas Inventory (see Sections 2.1.3 and 1.2.5.2).

In addition to the field survey, a Corporate Data Request was distributed in order to solicit additional insight into data that are not possible to observe with a one-time site visit, including fugitive survey and repair history, and episodic or other sources of methane emissions. These data were used to develop time series modeling parameters such as the Leak Occurrence Rate. These parameters are derived by combining historical data with direct observations from the field survey in order to better characterize the temporal aspect of methane emissions.

[2] Excluding pneumatic venting

[3] Brandt, A.R., G.A. Heath, D. Cooley (2016). Methane leaks from natural gas systems follow extreme distributions. Environmental Science & Technology. DOI: 10.1021/acs.est.6b04303

[4] Compositional data was not obtained for any emission sources; venting from Produced Water Tanks may include significantly less methane than other vent sources and are distinguished within the scope of this report.

In January 2019, following the presentation of the draft study results, a workshop led by DXD Consulting Inc. (DXD) was conducted to consider the experience of oil and gas industry experts on factors that could influence certain parameters of interest. Input was solicited from these representatives for the purposes of adding context to numerical results of forecasting and backcasting time-series methane modeling. Three temporal states – distant past, recent past, and future – were interrogated across six specific focus areas in terms of the direction and relative magnitude of change from the “present” observed in the field study. The workshop sought to bring context and industry experience to the forefront to guide changes to modeling parameters over different time periods. The principal objective of the industry workshop was to solicit expert feedback on operator practices and historical and future design considerations that may impact methane emissions from upstream facilities. This uniquely collaborative session between industry and regulators was intended as an opportunity to extract technical feedback from industry experts on how their operations have evolved over time. Insights into key drivers that might influence parameters of interest for time-series modelling was determined through focused small-group discussions. It is expected that others can benefit from these insights when completing emissions modelling assessments over various time periods.

The data generated by the BC Methane Emissions Field Study encompass varied geographic, facility, production, and temporal coverage and were analyzed using transparent methodologies. The insights and results are presented herein with additional commentary and context, along with the anonymized raw data.

Table of Contents

Glossary

- **Advisory Team:** Project representatives from BC CAS, BC OGC, MEMPR, ECCC
- **BC CAS:** British Columbia Ministry of Environment and Climate Change Strategy – Climate Action Secretariat
- **BC OGC:** British Columbia Oil and Gas Commission
- **CAPP:** Canadian Association of Petroleum Producers
- **Components:** Relevant to the classification and attribution of methane emission sources; in order to enable application of component-to-equipment ratios from previous research, definitions and component types match those employed by Clearstone et al (2018):[5]
    - Compressor Seals:
        - Reciprocating: Packing systems (seals) are used on reciprocating compressors to control leakage around the piston rod on each cylinder. A reciprocating compressor is deemed to have one seal associated with each compressor cylinder regardless of whether it is a single or tandem seal.
        - Centrifugal: Centrifugal compressors generally require shaft-end seals between the compressor and bearing housings. Either face-contact oil-lubricated mechanical seals or oil-ring shaft seals, or dry-gas shaft seals are used. A centrifugal compressor has two seals, one on each side of the housing where the shaft penetration occurs.
    - Connector: Each threaded, flanged, mating surface (cover) or mechanical connection is counted as a single connector. Welded or backwelded connections are not counted.
    - Control Valve: A valve equipped with an actuator for automated operation to control flow, pressure, liquid level or other process parameter.
    - Meter: A flow measurement device is counted as a single component. The connections on the upstream and downstream sides of the device are counted as separate components.
    - Open-Ended Line: Each valve in hydrocarbon service that has process fluid on one side and is open to the atmosphere on the other (either directly or through a line) is counted as an open-ended line. If the open side of the valve is fitted with a properly installed cap, plug, blind flange or second closed block valve, or is connected to a control device, then it is no longer considered to be open-ended.
    - Pressure Relief Valves and Pressure Safety Valves (PRV/PSV): Each pressure-relief valve that discharges directly to the atmosphere or through a vent system is counted as a single component.
    - Pump Seal: Each pump in hydrocarbon service may leak from around the pump shaft and is typically controlled by a packing material, with or without a sealant. It may be used on both the rotating and reciprocating pumps (and includes pneumatic injection pumps). Specially designed packing materials are available for different types of service. The selected material is placed in a stuffing box and the packing gland is tightened to compress the packing around the shaft.

[5] Clearstone Update of Equipment Component and Fugitive Emission Factors for Alberta Upstream Oil and Gas Study (https://www.aer.ca/documents/UpdateofEquipmentComponentandFugitiveEmissionFactorsforAlber-1.pdf). See Section 8.3 for additional detail on components.

  - Regulator: Most regulators are equipped with a vent where gas is released in the event the diaphragm inside becomes damaged.
  - Thief Hatch: Storage tanks connected to a VRU or flare do not emit gas unless the internal tank pressure exceeds the PRV or thief hatch set pressures (and intermittent venting occurs). When the tank pressure drops, the PRVs return to a closed position and typically don't leak. However, once opened, thief hatches remain partially open until an operator closes the hatch. Gas loss from partially open thief hatches is unintentional and therefore classified as a leak. Gas losses from storage tanks open to the atmosphere (i.e., not connected to a VRU or flare) are classified as a process vent (not a leak).
  - Valve: A valve that is **not** a control valve.
- **Control Instrument:** Any device used for process control (measurement and control of process variables) such as switches and controllers; predominantly includes the classifications:
  - Pressure controller: a device which continuously monitors pressure and outputs a corrective signal to the final control element based on the deviation from set point pressure
  - Pressure switch: a sub-type of pressure controller, capable of on/off output at preset pressure
  - Level controller: a device which continuously monitors fluid level and outputs a corrective signal to the final control element based on the deviation from set point level
  - Level switch: a sub-type of level controller, capable of on/off output at preset level
  - Positioner: a device which modulates the supply pressure to the control valve actuator to maintain a position based on the control signal
  - Temperature controller: a device which continuously monitors temperature and outputs a corrective signal to the final control element based on the deviation from desired temperature
  - Transducer: a combination of a sensor and a transmitter; converts physical signal (e.g. pressure) into electric signal (e.g. millivolts)
- **Crude Oil Single-Well Battery:** A production facility for a single oil well.[6]
- **Crude Oil Multiwell Group Battery:** A production facility consisting of two or more flow-lined oil wells having individual separation and measuring equipment but with all equipment sharing a common surface location.[6]
- **Crude Oil Multiwell Proration Battery:** A production facility consisting of two or more flow-lined oil wells having common separation and measuring equipment. Total production is prorated to each well based on individual well tests. Individual well production tests can occur at the central site or at remote satellite facilities. [6]
- **ECCC:** Environment and Climate Change Canada
- **Excessive Pneumatic Venting:** includes any gas release from pneumatic equipment that does not reflect normal operation, such as a release from the seal on the device casing. These types of releases were isolated during analysis as a separate category since they are treated differently under different regulations.
- **Facility:** Any site/location may be considered a facility within this report, including wellsites, but for analytical purposes facilities are batteries.
- **Fuel Gas:** See natural gas as the same definition was used for the purpose of this study.

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[6] Facility definitions excerpted from the Petrinex British Columbia Inclusion Project – Industry Readiness Handbook available at https://www.petrinex.ca/Initiatives/Documents/PBCIP_Industry_Readiness_Handbook.pdf

- **Fugitive Emissions (Equipment Fugitives):** The field collection team employed the following definition for distinguishing equipment fugitives (leaks) from vents: "A leak is the unintentional loss of process fluid past a seal, mechanical connection or minor flaw at a rate that is in excess of normal tolerances allowed by the manufacturer or applicable health, safety and environmental standards. An equipment component in hydrocarbon service is commonly deemed to be leaking when the emitted gas can be visualized with an infrared (IR) leak imaging camera or detected by other techniques with similar or better detection capabilities."[5] OGI was the only detection technology used in this study. Equipment fugitives were attributed to component types listed above including connectors, valves, control valves, PRV/PSV, meters, regulators, pump seals, thief hatches. During analysis some equipment fugitives were further sub-classified (e.g. Excessive Pneumatic Venting).
- **Gas Multiwell Effluent Measurement Battery:** A production reporting entity consisting of two or more gas wells where estimated production from gas wells in the battery is determined by the continuous measurement of multiphase fluid from each well (effluent measurement). Commingled production is separated and measured then prorated back to wells based on the estimated production. [6]
- **Gas Multiwell Group Battery:** A production reporting entity consisting of two or more gas wells where production components are separated and measured at each wellhead. Production from all wells in the group is combined after measurement and then delivered to a gas gathering system or other disposition. [6]
- **Gas Single Well Battery:** A production facility for a single gas well where production is measured at the wellhead. Production is delivered directly and is not combined with production from other wells prior to delivery to a gas gathering system or other disposition. [6]
- **Heavy Liquid:** Process fluid that is a hydrocarbon liquid at the operating conditions and has a vapour pressure of less than 0.3 kPa at 15°C.[5] No heavy liquid service was encountered in the study.
- **Large Facility:** Refers to Compressor Stations and Gas Plants. [6]
- **LDAR:** Leak Detection and Repair
- **Leak Occurrence Rate:** An important parameter used in time-series modeling to establish the fugitive emission factor magnitude, which considers the number of detected leaking components by type, the number of leaks detected but not repaired from the previous survey, the number of months since the last survey, and the number of components and facilities of each type. See Section 3.2 for calculation details.
- **Light Liquid:** Process fluid that is a hydrocarbon liquid at the operating conditions and has a vapour pressure of 0.3 kPa or greater at 15°C. Light/medium crude oil, condensate and natural gas liquids (NGLs) fall into this category. [5]
- **MEMPR:** British Columbia Ministry of Energy, Mines, and Petroleum Resources
- **Natural Gas:** The Petroleum and Natural Gas Act (PNG) defines as all fluid hydrocarbons, before and after processing, that are not defined as petroleum, and includes hydrogen sulfide, carbon dioxide, and helium produced from a well.[7] In the scope of this study, typically refers to fuel gas or instrument gas that is (or was assumed to be) predominantly methane.
- **Pneumatics (Pneumatic Devices):** Refers to control instruments and pumps, including non-pneumatic (e.g. electric drive) equipment according to the classifications above.

[7] Oil and gas Glossary and Definitions Version 1.11: February 2019, BC OGC (Available at https://www.bcogc.ca/node/11467/download)

- **Pneumatic Pump:** Any device used for chemical injection at wellsites, compressor stations, batteries or gas plants; no sub-classification was employed in this report although the observed pump types include diaphragm positive displacement pumps and electric drive positive displacement pumps.
- **Process Gas:** Process fluid that is a hydrocarbon gas at the subject operating condition.[5] For the purpose of the analysis process gas was defined as natural gas.
- **Project Team:** Cap-Op Energy, including its subcontractors Greenpath Energy, DXD Consulting, and Dr. Arvind Ravikumar
- **OGI:** optical gas imaging using infrared (IR) leak imaging camera
- **Reporting Facility:** Refers to a facility with a Reporting Facility ID from the BC OGC.
- **Site Classification (or Facility Types):** Sites, or facilities, were classified according to existing BC OGC classification schemes including gas wells, oil wells, single well batteries, and others as further delineated in Facility Types
- **Venting Emissions:** An intentional release of hydrocarbon gas directly to the atmosphere. Venting does not include partial products of combustion that might occur during flaring or other combustion activities. Vents were attributed to component types including open-ended line, compressor seal, and thief hatch.

Background and Context

British Columbia (BC) launched its Climate Action Plan in 2008 as one of the first jurisdictions in North America to formally address anthropogenic climate change with GHG emission reduction targets and a suite of programs to achieve them.[8] In 2016, BC's Climate Action Plan included programs launched to specifically target methane emissions from upstream natural gas production, including a reduction target of 45% by 2025 and a commitment to investing in infrastructure to power natural gas projects with clean electricity.[9] In December 2018, BC confirmed their methane emissions reduction target in the CleanBC Plan.[10] At a high level, BC's upstream methane emission reduction target is aligned with sub-national policies in neighbouring Alberta,[11] states including Colorado, California,[12] Ohio, Pennsylvania, and Wyoming as well as federally in Canada, the US, and Mexico.[13]

Methodologies have been established to model methane emission sources, including certain defined parameters (e.g. facility types, and equipment types). Inputs for these modelling methodologies should represent local operating configurations and production types, however they are often generic historical factors, developed in different jurisdictions. This study aimed to develop modelling parameters specific to BC operations.

The Province of British Columbia along with Environment and Climate Change Canada proposed and supported the field study and subsequent analysis to translate observations from the field to the defined time-series modeling parameters.

Following a description of the scope and approach, reporting of results is structured as follows:

CHAPTER	TITLE	SOURCE OF INFORMATION
CHAPTER 1	Field Observations	Field Survey Data
CHAPTER 2	Comparison to Contemporary Studies	Field Survey Data, Other Studies
CHAPTER 3	Fugitive and Episodic Emission Management Practices	Field Survey Data, Corporate Data Request
CHAPTER 4	Long Term Methane Emission Drivers	Expert Workshop

[8] British Columbia Climate Action Plan, 2008 (Available at https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cap/climateaction_plan_web.pdf)
[9] British Columbia Climate Leadership Plan, August 2018 (Available at https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/clp/clp_booklet_web.pdf)
[10] CleanBC, March 2019 (Available at https://blog.gov.bc.ca/app/uploads/sites/436/2019/02/CleanBC_Full_Report_Updated_Mar2019.pdf)
[11] Alberta Climate Leadership Plan, Implementation Plan 2018-2019 (Available at https://open.alberta.ca/dataset/da6433da-69b7-4d15-9123-01f76004f574/resource/b42b1f43-7b9d-483d-aa2a-6f9b4290d81e/download/clp_implementation_plan-jun07.pdf)
[12] Proposed Short-Lived Climate Pollutant Reduction Strategy, California Air Resources Board, April 2016 (Available at https://www.arb.ca.gov/cc/shortlived/meetings/04112016/proposedstrategy.pdf)
[13] Joint Statement on North American Climate Leadership, Environment and Climate Change Canada, September 2018 (Available at https://www.canada.ca/en/environment-climate-change/news/2018/09/joint-statement-on-north-american-climate-leadership1.html)

Scope

Facility Types

Upstream oil and gas production is generally comprised of wells, batteries, gathering and transportation systems, and upstream processing facilities. Since facility sizes tend to increase further down the supply chain, the upstream sector is characterized by large numbers of small facilities (9,191 active wells and 327 active batteries)[14] which can be highly diverse in their operating practices and the type of equipment found on site. Diversity at upstream sites is also a result of diverse operators, design and operating practices, facility ages, and product characteristics. For example, the presence of liquids can alter the equipment and operating practices of upstream sites.

Characterizing the upstream sector accurately is challenging because large sample sizes are required for statistical significance but field data collection costs scale with both sample size and facility size/complexity. In order to ensure sufficient sample sizes, Compressor Stations and Gas Plants (Large Facilities) were excluded in order to focus on wells and batteries, however some compressors were observed at smaller facilities. Specifically, the study considered the following facility types (consistent with Petrinex definitions):

- Wells (W)
- Single-Well Batteries (SWB)
- Multiwell Group Batteries (MGB)
- Multiwell Proration Batteries (MPB)
- Multiwell Effluent Measurement Batteries (MEM)

Production Types

British Columbia produces oil and gas from the northwest end of the Western Canadian Sedimentary Basin. Oil production, comprising light crude oil and natural gas condensates, is secondary to gas production in most areas, and both are produced from a mix of older legacy wells ("Conventional") as well as newer Shale and Tight wells. Based on the BC OGC records, very few facilities are classified as producing "Shale Gas" as distinct from "Tight Gas" and so these were combined to form a single production category (Tight Gas (T)). Tight Gas was distinguished from Conventional Gas (C), and a single Oil (O) category was considered to include sites classified as either Tight Oil or Conventional Oil.

Specifically, the study considered the following categories of facility and production types:

- Well Site
- Gas Single Well Battery
- Gas Multiwell Group Battery
- Gas Multiwell Effluent Measurement Battery
- Crude Oil Single-Well Battery
- Crude Oil Multiwell Proration Battery
- Crude Oil Multiwell Group Battery

[14] "Active" was defined based on May 2018 production reporting.

Source Types

Upstream methane sources result from intentional or unintentional releases to atmosphere, or from combustion. Combustion emission sources such as flares were considered outside the scope of the study. Intentional (venting) sources of emissions were attributed to pneumatic devices and other specific pieces of equipment wherever possible (see Sections 1.2.5.2 and 1.2.4.2, respectively). Unintentional (equipment fugitive) emissions were attributed to specific components (see Section 1.2.3.2 for examples).

Time Period

Field data collection occurred during the month of September 2018, with a single inspection at each location (snapshot survey). Between October 2018 and February 2019, historical site-level data was acquired concerning emissions and activities that occurred between 2016 and February 2019. In January 2019, expert opinion was solicited regarding past, present, and future time trends and their impacts on emissions (see Chapter 4).

Approach

A field protocol and sampling plan were developed to facilitate the development of numerical results on a per-facility basis (emitting and non-emitting equipment counts), per-component basis (fugitives, where possible) and including the quantification of emitting equipment.

Greenpath lead the development of the field protocol for on-site data collection methodologies, in consultation with Cap-Op and the advisory team, with particular focus on:

1) Methodology employed to estimate equipment and component counts/inventories where applicable
2) Methodology employed to quantify emissions from fugitives and emitting equipment

The protocol that was selected balanced time and resource constraints with the granularity and accuracy of data collected. The protocol required a two-person team, including contractors and BC OGC Inspectors, who were tasked with the following:

- Inventory of pneumatic devices, process equipment and other potential vent sources and fate of vent sources (compressor packing, tank controls)
- Inspection via OGI Camera and quantification of leaks and vents via High Flow Sampler
- Collection of supplemental information to aid in quantification

Concurrently, Cap-Op lead the development of the sampling plan, in consultation with Greenpath and the advisory team, with particular focus on:

3) Types of facilities to be considered for study (e.g. Wells, Batteries)
4) Production types to be considered for study (e.g. Tight Gas, Conventional Oil)
5) Representation of the population using randomly selected sample sets of sites

Site Selection

Participation in the study was voluntary, but was structured as “opt-out” instead of opt-in. This allowed the project team to select sites randomly in order to form a robust sample. The sites visited were selected through the process detailed below before any contact with producers. All but one producer selected allowed the field survey to take place which prevented or minimized a "coalition of the willing" effect that may introduce bias to studies relying only on voluntary participation.

Site selection was done using a quasi-random process, seeking to balance the statistical benefits of random selection with logistical challenges presented by visiting a large number of geographically dispersed locations, and the limited amount of time available for both site selection and field data collection. Filtered data were provided by BC OGC which contained records of the most recent available month of production reporting, the facility type categories and production type categories as well as other identifying information.

The approach involved filtering the population of wells and batteries in BC before applying random selection procedures. The populations in each facility-production type category were filtered according to the principles outlined in Table 1:

Table 1: Well and battery population filters

Filter Applied	Rationale
Active (or recently active) operations only	Inactive (shut-in) locations are out of scope.
Exclude extremely remote locations (e.g. Horn River)	Focused on Montney due to provincial production and forecasts.
Battery not co-located with another battery in the same LSD	Co-located facilities, or those with multiple permits at the same location, require manual review of metering schematics in order to correctly attribute emissions and equipment. This level of manual review was out of scope of the study.
Wells geographically proximate to batteries (3 km)	Improve efficiency of transportation logistics.

While it is acknowledged that each of the filters applied to the population introduces bias to the results, the filtering also increased the sample size by allowing the field team to visit more locations. This trade-off was considered in the context of the advisory team's objective of focusing on most sensitive parameters for time-series modeling. The focus was to characterize smaller sites in BC which were believed to differ from Alberta sites covered by most other research. In this context, observing a significant cross-section of well and battery facility/production categories was prioritized.

A randomized selection process was then applied to the filtered list of facilities and wells resulting in a set of sites that could be tested for whether it was representative of the overall population. The process is summarized in Figure 1:

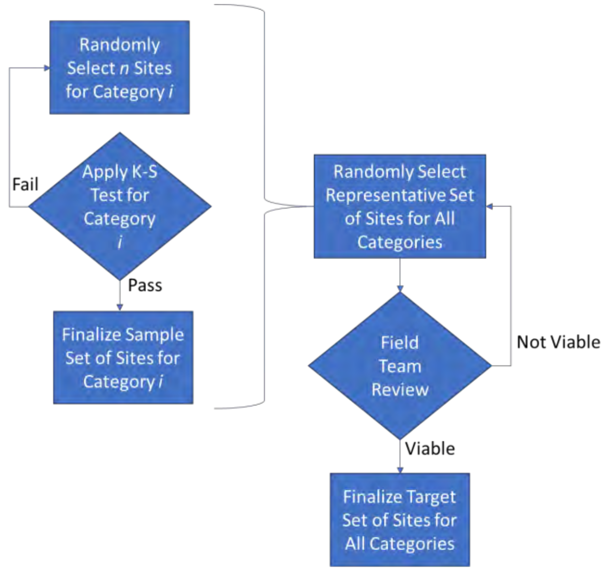

Figure 1: Site selection iterative review process

The number of sites visited in a given category was driven by the facility type (size considerations), the relative focus (Tight Gas prioritized over Conventional) and the available population size. The following table summarized sample sizes as % coverage of the available population:

Table 2: Coverage ratios - sample size as percent of available population[15]

	Oil	Conventional	Tight	Average
Wells	38%	47%	52%	46%
SWB	19%	24%	100%	48%
MGB	100%	21%	45%	55%
MPB	19%			19%
MEM		16%	22%	19%
Avg	46%	20%	56%	35%

Representativeness

Representativeness was quantitatively assessed using the Kolmogorov-Smirnoff goodness-of-fit test (K-S test). The basis that was used for the K-S testing was the distribution of normalized energy production rates, which was characterized for both the sample sites and the available population of sites (two-sample K-S test). The test is designed to assess whether the two samples represent the same underlying population and was run using a significance level of alpha = 0.05.[16] Regardless of the alpha selected, small sample sizes due to time and resource constraints may have an effect on the utility of the K-S test since the threshold for pass/fail increases with fewer samples to compare.

[15] Available population refers to the set of wells and batteries that passed the filtering criteria described in Table 1. Note that coverage of wells only refers to wells within 3km of selected batteries as per Table 1.
[16] Alpha level is the probability of rejecting the null hypothesis when the null hypothesis is true.

The K-S test was applied at the level of each individual combination of facility type and production type, as well as on the entire selection. The entire selection was then assessed against the "available population" of wells and batteries after application of the filtering criteria above. All assessments passed the K-S test.

The available population was also assessed against the overall population of all active wells and batteries in BC. Figure 2 illustrates the effect of the filtering process:

Figure 2: Distribution of normalized energy production rates before and after application of site selection filters

Energy production rates are accessible and present as a reasonable characteristic with which to assess representativeness, although emissions are not necessarily robustly correlated with energy production rates, and so additional considerations for diversity were included qualitatively on the entire selection:

- Age, represented by date of first production
- Operator mix

The date of first production was determined using BC OGC records. For facilities, the available population included first production dates covering 30 years, from 1989-2018 and the target sample included facilities representing 22 (73%) of these first production years spanning 1989-2017. For wells, 37 distinct years were represented from 1958 to 2017. Figure 3 shows the distribution of first production years among the visited wells:

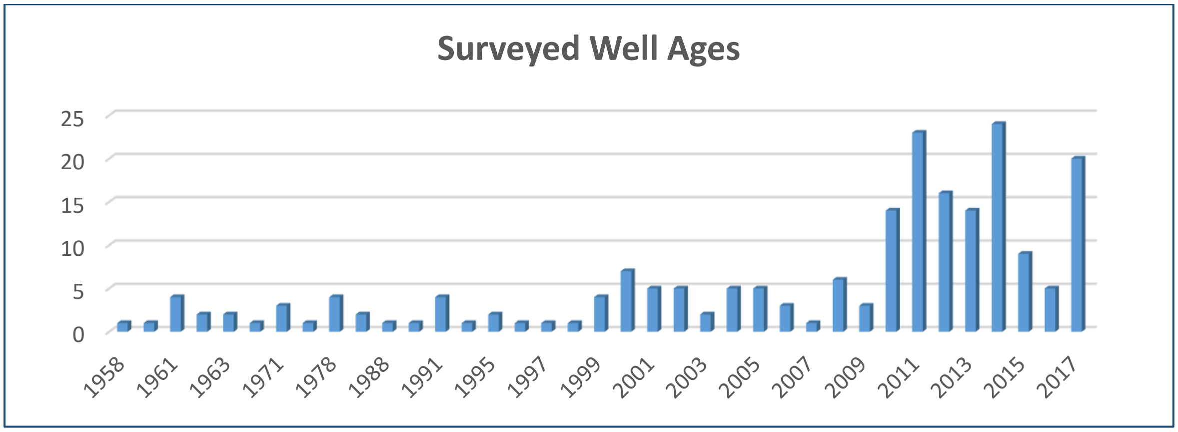

Figure 3: Year of first production - visited wells

A total of 47 operator names were represented in the available population of facilities, of which 21 operated facilities that were visited (45%). The participation rate of each operator varied between 1 and 47 sites with approximately half of the operators having 10 or more sites each.

Site Classification (Study Code):
[Facility/Site Type] + [Production Category]
e.g. MGBT: Multiwell Group Battery – Tight Gas
SWBO: Single-Well Battery – Oil

Figure 4: Site classification used for selection and results analysis includes facility type and production type

BC OGC records include redundant information within the facility type classifications that also indicates production type (e.g. Gas Single Well Battery and Crude Oil Single Well Battery are different Facility Types). These were grouped logically where possible (e.g. all Single Well Batteries) and then re-stratified using the more detailed production characterization that is available within each facility's record (e.g. Tight Gas, Non-Associated (Conventional) Gas, etc.). A classification scheme for site selection (and analysis/reporting) was developed which combines the facility type and production type as explained in Figure 4.

Target and Actual Sample Sets

The site selection process resulted in the selection of 254 locations within the study areas outlined in Figure 5 (266 were ultimately surveyed). The field team, comprising Greenpath Energy staff and OGC inspectors, was provided with the list of selected sites and site information and instructed to visit as many as possible.

With exceptions noted below in Table 3, the actual sites visited matched the target sites and priority focus points for the study. The representativeness tests were re-run to compare the actual sample set of sites to the available population and representativeness was maintained both quantitatively and qualitatively in all facility type and production type categories.

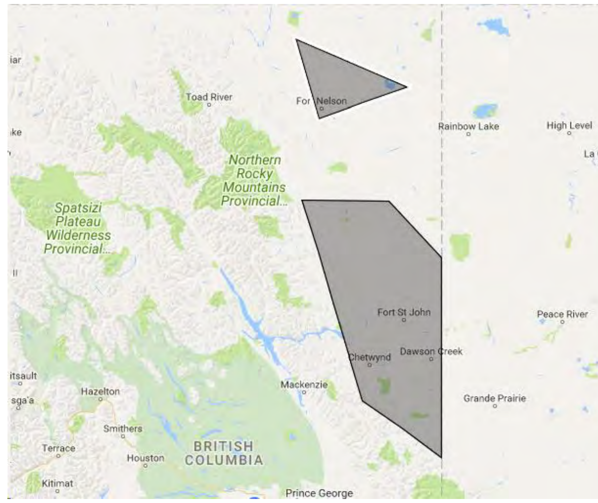

Figure 5: Target study areas

Table 3: Actual locations sampled as percent of planned by facility and production type

	Oil	Conventional	Tight	Total
W	124%	128%	145%	137%
SWB	100%	80%	60%	82%
MGB	100%	29%	150%	100%
MPB	100%			100%
MEM		88%	120%	106%
Facility Total	100%	65%	120%	97%

All sub-categories in Table 3 with less than 100% represent categories with very small sample sizes to begin with, for example for SWBT sub-category 3 of 5 planned facilities were visited.

Field Data Collection

Equipment counts and classifications require working knowledge of oil and gas operations. Qualified personnel are also required to properly operate specialized emissions detection and measurement equipment and to accurately identify equipment and component types. The field team was responsible for source identification and quantification according to the following study design elements:

- Equipment Fugitive emissions
  - OGI Camera, trained technician
  - Hi-Flow Sampler
  - Some visual estimation required
    - For inaccessible methane releases detected[17]

[17] For example, sources at height. Visual estimation employed at discretion of field team.

- Venting emissions
  - OGI Camera, trained technician
  - Hi-Flow Sampler
  - Some visual estimation required
- Major equipment inventory
  - Direct observation (count)
  - Emitting or non-emitting determination
  - Emission control observation
- Pneumatic equipment inventory[18]
  - Direct observation (inventory)
  - Emitting or non-emitting determination
- Component counts
  - Derived from Clearstone 2018 where possible
  - Otherwise direct observation (count)

Data Schema

Figure 6 outlines the data elements that were captured by the field team at each site:

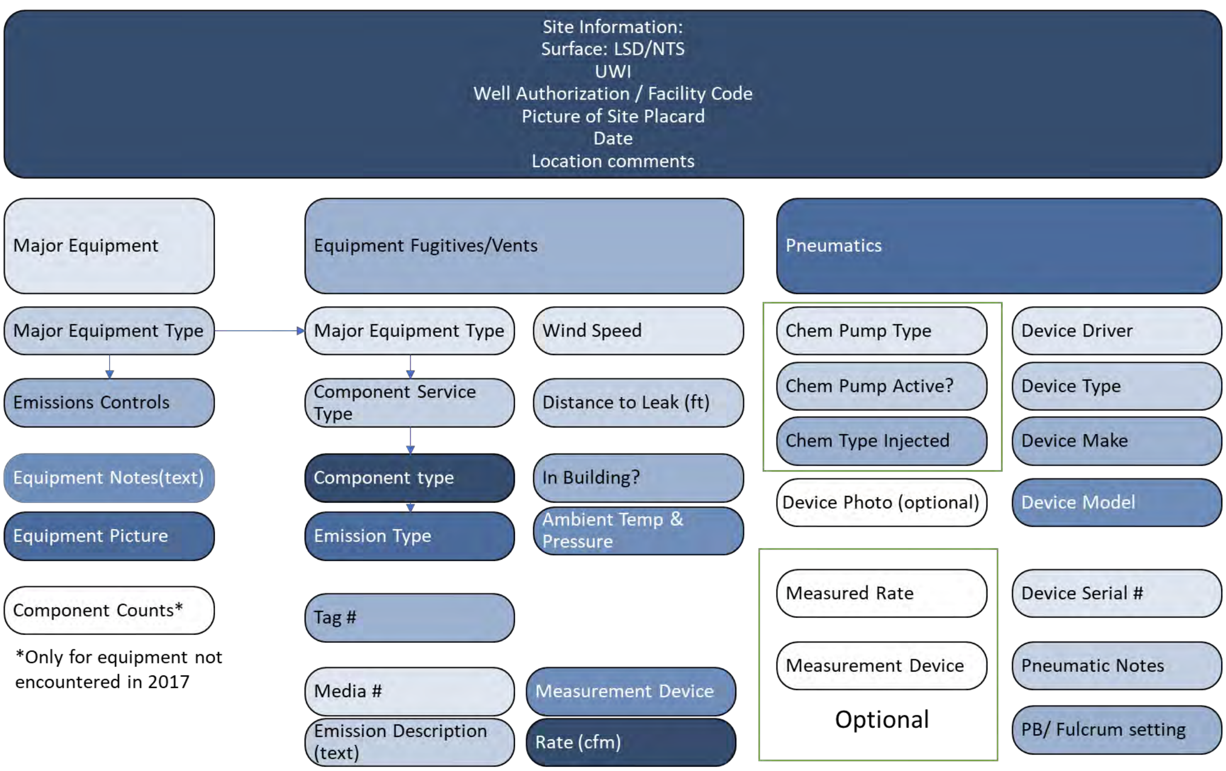

Figure 6: Data elements collected by field team

[18] Includes non-pneumatic control instruments and chemical injection pumps (e.g. electric devices)

Where possible, existing component-to-equipment ratios were leveraged for this study (see below). Some equipment was observed in BC that was not observed in Alberta during Clearstone 2018, and these equipment types were subject to component counts on an exception basis, as further delineated below and in Table 6 of Section 1.1. See Section 1.1 Analytical Approach for additional details.

Use of Existing Factors

The scope was determined to ensure representative results from the facility and production types visited. Existing factors were employed for two data points (where possible): component counts and pneumatic device vent rates.

It was determined that component-per-equipment ratios from existing literature could be combined with observed equipment counts in order to develop results that represent BC operations. This approach avoided the need to directly acquire component count information which is highly time consuming. The number of components per piece of major equipment is expected to be the same in Alberta and BC. As such, observed equipment counts were combined with published average components per major equipment / process block to determine the total number of components per facility type. These component counts are used in combination with the detected leaks to characterize fugitive emissions from the facilities visited during the survey. Clearstone 2018 was used as it developed representative component counts per major equipment type for AB.

Release rates from pneumatic control instruments and pumps were not measured during this study, but estimated based on the observed makes and models in order to facilitate comparisons between source release type (e.g. venting emissions and fugitive emissions) as well as comparisons to other studies. The pneumatic controller release rates from recent studies were used; including early work by Cap-Op and Greenpath (Prasino Study, 2014)[19] as well as more recent measurements campaigns by Spartan Controls and Greenpath Energy.[20] Other meta-analysis of existing fieldwork has also been done.[21]

Fugitive History and Repair Data Collection

A Corporate Data Request (CDR) was developed in order to obtain data needed for time-series modeling parameter development that could not be obtained from the site visit observations.

The CDR solicited historical information regarding the most recent fugitive survey and any associated leak repair information. Company logs were requested for the same set of sites as was visited by the field team.

Episodic and Other Sources of Methane Emissions Data Collection

The Corporate Data Request solicited historical information regarding episodic and other sources of methane emissions based in part on Cap-Op's 2017 report for Environment and Climate Change Canada (ECCC)[22]. Company logs were requested for the same set of sites as was visited by the field team.

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[19] Final Report For Determining Bleed Rates for Pneumatic Devices in British Columbia, The Prasino Group (now Cap-Op Energy), December 2013 (Available at http://www.bcogris.ca/sites/default/files/ei-2014-01-final-report20140131.pdf)

[20] Pneumatic Vent Gas Measurement, Brian Van Vliet and Spartan Controls, April 2018 (Available at https://auprf.ptac.org/wp-content/uploads/2018/05/Pneumatic-Vent-Gas-Measurement.pdf)

[21] Osman, A. (2016). Determining Pneumatic Controller and Pumps Release Rates, available by request from ECCC.

[22] Available from www.capopenergy.com

Episodic emissions are from non-continuous or highly variable emission sources, and include:

- Blowdown, purging, and other de-pressure events
- Liquids loading/unloading from tanks
- Compressor starts (gas starts)
- Flare operational issues (e.g. unlit flares)

Temporal Trends

A variety of elements confound the acquisition of objective, accurate, comprehensive and comparable datasets on temporal trends in methane emissions. Constraints include changes in reporting regulations over time (and differences between jurisdictions), inaccessible or nonexistent recordkeeping, asset acquisition/divestitures, and employee turnover. That said, for a time-series model to back-cast and forecast methane emissions accurately it is necessary to better understand the direction and magnitude of change.

Workshop Objectives

In January 2019, following the presentation of the draft study results, a workshop led by DXD Consulting Inc. (DXD) was conducted to consider the experience of oil and gas industry experts on factors that could influence certain parameters of interest. Input was solicited from these representatives for the purposes of adding context to numerical results of forecasting and backcasting time-series methane modeling. The incorporation of industry knowledge to the MEFS is intended to enhance stakeholder understanding of the study results and to offer guidance on temporal implications to BC's emissions performance for time-series modeling applications.

The principal objective of the industry workshop was to solicit expert feedback on operator practices and historical and future design considerations that may impact methane emissions from upstream facilities. A key outcome of the workshop was for BC OGC, ECCC and the government of British Columbia through BC CAS and MEMPR to gain a better understanding from industry representatives, of how British Columbia oil and gas facilities and operating practices (regarding methane release drivers and management practices) may have differed in the past and how they may change in the future due to various factors.

Workshop Methodology

The workshop was designed to build upon the presentation of current operational practices and emission profiles as observed during the BC Methane Emissions Field Study. The workshop participant list targeted oil and gas producers with operations in BC that were visited during the Study, as well as Federal and BC provincial regulators.

The workshop focused on gaining industry insights on six factors that could influence modeling parameters, or modeling drivers, that impact time-series methane emissions modeling. Specifically, industry experts were asked to comment on how their facilities and operating practices (as they could impact methane management) were different in the past and would be different in the future, with respect to these six drivers. Participants were asked to characterize these differences in terms of directionality (i.e., more or less than current practices) and magnitude as banded into 5 categories. Magnitude categories ranged from **not applicable** to **neutral** (0-15%) to high (>= 100%). Table 4 shows the six drivers considered, and Table 5 shows the scale for analysis of these drivers.

Table 4: Modeling Driver

1	Equipment to Facility Ratios
2	LDAR inspection frequencies
3	Prevalence of high bleed pneumatic devices
4	Level of implementation of mitigation technologies, (for example, flares, vapour recovery)
5	Level of preventative maintenance conducted
6	Prevalence of non-emitting pneumatic devices

Table 5: Scale for characterizing the directionality and magnitude of change for each driver

Directionality and Magnitude of Change	Estimated Percent Change to Driver (or Equipment Ratios)
↑↑↑ (3)	> 100%
↑↑ (2)	50% to 100%
↑ (1)	15% to 50%
---	Neutral - No Change (+/- 15%)
NA	Not Applicable (doesn't exist)
↓ (-1)	15% to 50%
↓↓ (-2)	50% to 85%
↓↓↓ (-3)	>85% (didn't exist in past or doesn't exist in future)

Notably, a neutral or no-change scenario was given a range of zero change to 15% change in either direction. A change of -3 indicates that a practice essentially did not exist in the past or will not exist in the future.

The workshop was designed to gain industry knowledge of how those drivers, with respect to operations and practices, have changed over the past several years, and how they are expected to change, relative to current day, in the future. To collect this information over time, the following periods were defined for the purposes of the workshop:

Distant Past: this period is defined as pre-2009 and pre-dates the requirements for GHG reporting in British Columbia.

Recent Past: this period is defined as 2010 to 2015 and reflects the growing influence of unconventional gas production and potential liquefied natural gas overseas sales channels.

Current: this period is defined as 2016 to 2019. This period pre-dates the implementation of federal methane regulations and British Columbia methane regulations.

Future: this period is defined as 2020 to 2030. This period begins after the implementation of federal and provincial methane regulations. It was not considered practical to characterize industry practices and operations beyond 2030.

Initially, two future states were considered:

Future – Compliance: this state assumes that industry is compliant with the currently proposed provincial and federal regulations and that market and regulatory conditions remains as they are currently.

Future – Best-In-Class Methane Emissions Reductions: this state assumes that industry is not only compliant but exceeding the regulations and leading the world in methane emissions reductions. During the facilitated workshop, this state was considered to be redundant, because federal and provincial regulations is expected to position BC-based oil and gas production as leading the global industry in methane emissions reductions.

Based on feedback during the workshop, these two future states were considered to be the same, and the single future state in which Producers were compliant with the federal and provincial regulations was evaluated during the workshop. Participants were asked to characterize projected operations and behaviours for the future state, including anticipating practices or changes in operations that have no defined certainty of occurring in the future.

The following guidance was provided:

- The magnitude and directionality of change are always in relation to the current state, and not the state before or after it.
- The future state assumes that BC is compliant with methane regulations.
- Only British Columbia oil and gas production was to be considered.

To conduct the workshop, the participants were put into three groups, with even representation of producers and regulators/government in each group. Groups were first asked to define the conditions and activities associated with each temporal state. This exercise ensured a common understanding of the temporal state prior to investigating each of the six modeling drivers. Subsequently, for each model driver noted above, the groups assigned directionality and magnitude of change relative to current operations for all six drivers across three temporal states: distant past, recent past and future. Commentary framing each rating was collected and results of each time period were presented and discussed as a group. Finally, for the future state, the three groups came together to integrate diverging points of view, resulting in workshop-wide general agreement on broad trends.

Chapter 1: Field Observations

1.1 Analytical Approach

1.1.1.1 Major Equipment Survey

Major equipment was counted during the field survey at all sites that were visited. The list of major equipment considered are listed in Table 7. Recent field work to determine component counts for various major equipment types has been undertaken in Alberta (Clearstone 2018). It is not expected that these component counts will differ between operations in BC and Alberta as the equipment shares common manufacturers and is often designed and installed by similar firms. If major equipment was found during the field survey which did not have associated component counts in Clearstone 2018, its components were counted. Site-level component count averages are determined by multiplying the total major equipment counts by their respective component count from either Clearstone 2018 or from the field survey. Further details on major equipment types are provided in Table 6 and below. Overall component count averages are a combination of the Clearstone 2018 study and the field survey (for unique equipment) shown in Table 6. Note that equipment pressurization or in-service status at the time of survey was not considered as a basis for exclusion (all equipment observed to be associated with a site is included). Appendix A includes additional information and detail for consideration.

Table 6: Major Equipment Component Count from Survey and Clearstone 2018[23]

Major Equipment – Component Counts from Field Study	Major Equipment – Component Counts from Clearstone 2018
Dehydrator - Dessicant	Catalytic Heater
Gas Sweetening: Sulfinol	Dehydrator - Glycol
Heat Trace System	Flare KnockOut Drum
Sand Separator	Gas Boot
Stabilization Tower	Gas Metering Building
Thermal Electric Generator	Gas Pipeline Header
	Gas Sweetening: Amine
	Incinerator
	LACT Unit
	Line Heater
	Liquid Pipeline Header
	Liquid Pump
	Pig Trap - Gas Service
	Pig Trap - Liquid Service
	Pop Tank
	Power Generator (natural gas fired)
	Process Boiler
	Production Tank Fixed Roof - Light Liquid
	Reciprocating Compressor
	Reciprocating Compressor - Electric Driver
	Screw Compressor
	Screw Compressor - Electric Driver
	Separator
	Storage Bullet
	Treater
	Well Pump

[23] Equipment definitions available in Clearstone 2018 Section 8.4

	Wellhead (Gas Flow)
	Wellhead (Gas Pump)
	Wellhead (Oil Flow)
	Wellhead (Oil Pump)

Major equipment is categorized under each site classification to determine average major equipment per site classification for the surveyed sites. Some site classifications (e.g., WT) are extensively surveyed (WT had 123 sites surveyed), whereas some site classifications had very low sample sizes (e.g., 2 MGBC sites visited). This will affect the accuracy and reliability of the average major equipment per site calculations as smaller sample sizes may not accurately account the differences between sites with the same classification.

1.1.1.2 Leaks and Vents Quantification

Leaks and vents observed during the field surveyed were measured if possible and estimated if measurement was not possible, at the discretion of the field team based on safe operating practices. The ambient conditions during measurement or estimation were also recorded. Using the ambient conditions and measured/estimated volumetric rates, a corrected leaks/vent rate is calculated using the combined gas law below.

Equation 1,

$$\frac{P_i V_i}{T_i} = \frac{P_f V_f}{T_f}$$

Where,

P_i, V_i, and T_i, = the initial Pressure, Volumetric flow rate, and Temperature recorded in kPa, m^3/hr, and °C respectively (temperatures recorded in °C but converted to °K throughout)

P_f and T_f, = Pressure and Temperature at standard conditions (101.325 kPa and 15°C respectively)

V_f = Corrected volumetric flow rate in m^3/hr

Leaks and vents are classified and analyzed based on source component, major equipment, site classification, volumetric flow rate magnitude, and whether they were estimates or measurements.

Field staff classified excessive pneumatic venting as open-ended lines (OELs) during data collection. These releases have been re-classified as excessive pneumatic venting to better represent the source of the observed emissions. These sources may have been categorized as open ended lines in previous studies. Therefore, for purposes of multiple different jurisdictions and differences in regulations around treatment of these emissions, these 42 leaks have been re-assigned from open-ended lines to excessive pneumatic venting to allow parties to determine their own methods to treat these emissions. these excessive pneumatic venting instances could not be attributed to a specific make and model at the site for a variety of reasons (e.g., instrument vent header leaks associated with multiple devices). Emissions categorized by the field team as open-ended line *venting* was not observed to be related to the operation of pneumatics. Venting from OELs mostly resulted from wellheads (surface casing vent flows) at ~75% of OEL vent sources.

1.1.1.3 Pneumatic Count and Pneumatic Venting

Pneumatics were counted during the field survey with data on device type, drive type (e.g., electric, solar, fuel gas (natural gas), etc.), chemical injection type, and make and model. Some limited data were also gathered regarding flow rates and pressures, but pneumatic vents were not directly measured. Any devices that may be pneumatically actuated (e.g. lube oil pumps) that were not classified as control instruments or chemical injection pumps were included in the major equipment inventory and not in the pneumatic inventory, in the same way that gas starter units would not be inventoried separately from compressors.

Pneumatics that were not fuel gas driven were assumed not to vent methane as part of normal operation. These pneumatics drives include electric, instrument air, solar, and propane. Pneumatic counts were analyzed and classified based on drive type and pneumatic device type from the following list;

- Pump,
- Level Controller,
- Transducer,
- Level Switch,
- High Level Shut Down Switch,
- Positioner,
- High Pressure Shut Down Switch,
- Pressure Controller,
- Pressure Switch,
- Plunger Lift Controller,
- Temperature Switch, and
- Other

Fuel gas pneumatics makes and models were verified so that estimates for pneumatic venting could be calculated. Pneumatic vent rates were estimated using available data from Alberta Environment and Parks Quantification Protocol for GHG Emission Reductions from Pneumatic Devices – Table C2,[24] WCI 2013,[25] the Prasino Study,[19] Alberta Energy Regulator's Manual 15,[26] PTAC Level Controller Study,[27] and in some cases manufacturer's specifications. Pneumatic vent data was matched based on the make and model of the fuel gas pneumatics surveyed. This method to estimate pneumatic venting requires reliance on available public studies that typically have varying vent rate results for pneumatic makes and models.

[24] Quantification protocol for greenhouse gas emission reductions from pneumatic devices (version 2.0), Alberta Environment and Parks, January 2017 (Available at https://open.alberta.ca/publications/9781460131633)
[25] WCI Quantification Method 2013 Addendum to Canadian Harmonization Version, Western Climate Initiative, December 2013 (Available at https://www2.gov.bc.ca/assets/gov/environment/climate-change/ind/quantification/wci-2013.pdf)
[26] Estimating Methane Emissions, Alberta Energy Regulator, December 2018 (Available at https://www.aer.ca/documents/manuals/Manual015.pdf)
[27] Level Controller Emission Study Fisher L2 and Improved Relays, Norriseal 1001As and EVS, Greenpath Energy, October 2018 (Available at https://auprf.ptac.org/wp-content/uploads/2018/10/Final-Report-Level-Controller-V8-20181003.pdf)

Other analyses can be done based on the make and models of the pneumatics determined from the field survey and analysis in this study to determine a possible range of vent rates.

Excessive pneumatic venting is not included in this section, as it is considered in the section on fugitive emissions. Current regulation surrounding excessive pneumatic venting varies across jurisdictions and excessive pneumatic venting is classified as either a vent or a leak in different regulations. This study adopts BC's requirements under the Drilling and Production Regulation by classifying this source as a fugitive emission.

1.2 Results

1.2.1 Major Equipment Counts

Major equipment in hydrocarbon service were counted for each location surveyed. The counts included both operating and pressurized non-operating equipment from the list in Table 7 and Table 8. The average (mean) process equipment count for a given facility subtype or well status is determined using the following relation:

Equation 2,

$$\bar{N}_{\mathrm{M}E} = N_{\mathrm{M}E} / N_{\mathrm{F/W}}$$

Where,

$\bar{N}_{ME}$ = average (mean) major equipment count for a given site classification,

N_{ME} = total number of process equipment surveyed for a given site classification,

$N_{F/W}$ = total number of sites visited of the considered site classification (12 site classifications)

Average and total major equipment counts per facility subtype are presented in Table 7 and Table 8 respectively.

Table 7: Average Major Equipment per Facility Type

	Site Classification (Number of Sites Surveyed)											
Major Equipment List	**WT (123)**	**WO (31)**	**WC (51)**	**SWBT (3)**	**SWBO (7)**	**SWBC (4)**	**MPBO (7)**	**MGBT (15)**	**MGBO (4)**	**MGBC (2)**	**MEMT (12)**	**MEMC (7)**
Catalytic Heater	1.50	0.52	2.00	2.00	1.71	1.75	7.29	5.93	4.00	1.00	15.75	4.29
Catalytic Incinerator			0.02		0.14			0.07				
Dehydrator - Dessicant						0.25		0.20				0.29
Dehydrator - Glycol	0.02					0.25	0.57	0.40			1.17	0.29
Expansion Tank							0.14					
Flare KnockOut Drum	0.04		0.39	0.33	0.29	0.25	1.43	0.93	0.75		1.50	0.86
Gas Boot							0.14	0.07			0.08	
Gas Metering Building	0.01		0.06									0.14
Gas Pipeline Header	0.03		0.02		0.14	0.25	0.57	0.40	0.75	0.50	0.17	0.14
Gas Sample and Analysis System	0.02							0.07			0.25	0.29
Gas Sweetening Scavenger	0.02											
Gas Sweetening: Amine								0.07			0.08	
Gas Sweetening: Sulfinol								0.13				
Heat Trace System	0.01							0.33			0.25	
Incinerator							0.29	0.20	0.25		0.08	
LACT Unit							0.29					
Line Heater	0.08	0.03	0.31		0.14	0.50		0.07			0.17	0.14

Major Equipment List	Site Classification (Number of Sites Surveyed)											
	WT (123)	WO (31)	WC (51)	SWBT (3)	SWBO (7)	SWBC (4)	MPBO (7)	MGBT (15)	MGBO (4)	MGBC (2)	MEMT (12)	MEMC (7)
Liquid Pipeline Header	0.02	0.13					0.71	0.20			0.08	
Liquid Pump							3.57	0.73			0.42	0.43
Lube Oil Tank							0.14					
Meter Building	0.10		0.37			0.25	0.14	0.20		0.50	0.17	0.14
Pig Trap - Gas Service	0.19		0.47	0.67	0.43	0.50	1.00	2.87	0.75	0.50	3.08	1.00
Pig Trap - Liquid Service	0.05	0.32	0.02		0.14	0.25	0.86		0.50		0.08	0.14
Pneumatic Panel							0.14					
Pop Tank	0.01	0.13			0.43		0.71	0.07	0.75			
Power Generator (natural gas fired)	0.02					0.25	0.43	0.67	0.50		1.33	1.00
Process Boiler							0.43	0.13				0.43
Production Tank - Water	0.04				0.43	0.25	1.14	2.20	0.75		2.75	0.57
Production Tank Fixed Roof - Light Liquid	0.03	0.13	0.02	0.67	0.86	0.25	3.57	0.73	1.50		1.67	0.71
PumpJack		0.03										
Reciprocating Compressor - Electric Driver							0.14	0.27				0.14
Reciprocating Compressor – Natural Gas	0.03				0.14		0.86	0.67			1.83	1.29
Sand Separator	0.15	0.03		0.33				0.33				
Screw Compressor - Electric Driver				0.33								
Screw Compressor - Natural Gas							0.71	0.20			0.17	
Separator	0.31	0.26	0.10	0.33	0.86	1.50	3.43	2.33	1.50	0.50	2.75	1.86
Shipping Pump							0.14					
Stabilization Tower								0.07				
Storage Bullet	0.03	0.10	0.27		0.29		0.14				0.17	
Thermal Electric Generator	0.15	0.10	0.49	0.67	0.43			0.27	0.50	0.50	0.17	0.43
Treater							0.86	0.07				
Unit Heater	0.01											
Water Storage Unit		0.03										
Well Pump		0.68	0.02		0.71	0.50	0.14					
Wellhead (Gas Flow)	1.01	0.16	1.14	0.33	0.14		0.43	0.60			0.08	
Wellhead (Gas Pump)	0.03											
Wellhead (Oil Flow)		0.26			0.43	0.50	0.14					
Wellhead (Oil Pump)		0.58	0.02		0.43		0.14					
Wellhead (Water Injection)								0.07				

Table 8: Total Major Equipment by Facility Type

Major Equipment List	Site Classification (Number of Sites Surveyed)											
	WT (123)	WO (31)	WC (51)	SWBT (3)	SWBO (7)	SWBC (4)	MPBO (7)	MGBT (15)	MGBO (4)	MGBC (2)	MEMT (12)	MEMC (7)
Catalytic Heater	185	16	102	6	12	7	51	89	16	2	189	30
Catalytic Incinerator			1		1			1				
Dehydrator - Dessicant						1		3				2
Dehydrator - Glycol	2					1	4	6			14	2
Expansion Tank							1					
Flare KnockOut Drum	5		20	1	2	1	10	14	3		18	6
Gas Boot							1	1			1	
Gas Metering Building	1		3									1
Gas Pipeline Header	4		1		1	1	4	6	3	1	2	1
Gas Sample and Analysis System	2							1			3	2
Gas Sweetening Scavenger	2											
Gas Sweetening: Amine								1			1	
Gas Sweetening: Sulfinol								2				
Heat Trace System	1							5			3	
Incinerator							2	3	1		1	
LACT Unit							2					
Line Heater	10	1	16		1	2		1			2	1
Liquid Pipeline Header	3	4					5	3			1	
Liquid Pump							25	11			5	3

Major Equipment List	Site Classification (Number of Sites Surveyed)											
	WT (123)	WO (31)	WC (51)	SWBT (3)	SWBO (7)	SWBC (4)	MPBO (7)	MGBT (15)	MGBO (4)	MGBC (2)	MEMT (12)	MEMC (7)
Lube Oil Tank							1					
Meter Building	12		19			1	1	3		1	2	1
Pig Trap - Gas Service	23		24	2	3	2	7	43	3	1	37	7
Pig Trap - Liquid Service	6	10	1		1	1	6		2		1	1
Pneumatic Panel							1					
Pop Tank	1	4			3		5	1	3			
Power Generator (natural gas fired)	2					1	3	10	2		16	7
Process Boiler							3	2				3
Production Tank - Water	5				3	1	8	33	3		33	4
Production Tank Fixed Roof - Light Liquid	4	4	1	2	6	1	25	11	6		20	5
PumpJack		1										
Reciprocating Compressor - Electric Driver							1	4				1
Reciprocating Compressor – Natural Gas	4				1		6	10			22	9
Sand Separator	18	1		1				5				
Screw Compressor – Natural Gas				1								
Screw Compressor - Electric Driver							5	3			2	
Separator	38	8	5	1	6	6	24	35	6	1	33	13
Shipping Pump							1					
Stabilization Tower								1				
Storage Bullet	4	3	14		2		1				2	
Thermal Electric Generator	19	3	25	2	3			4	2	1	2	3
Treater							6	1				
Unit Heater	1											
Water Storage Unit		1										
Well Pump		21	1		5	2	1					
Wellhead (Gas Flow)	124	5	58	1	1		3	9			1	
Wellhead (Gas Pump)	4											
Wellhead (Oil Flow)		8			3	2	1					
Wellhead (Oil Pump)		18	1		3		1					
Wellhead (Water Injection)								1				

1.2.2 Component Counts

Major equipment counts were matched with average component-to-equipment ratios. Component-to-equipment ratios were derived either from Clearstone 2018 or actual component counts on major equipment for which there were no existing ratios (as outlined in Table 6). This approach was used to determine average component counts for the various site types considered in this study. Component counts in the field were acquired for process equipment observed in the field that was not in Clearstone 2018. Some components serviced different gas and liquid types (process gas, fuel gas, light liquid, and heavy liquid), which is differentiated in Table 9 and Table 10. No heavy liquid service was encountered in the study. Below is the list of all component types considered:

- Compressor Seals,
- Connector,
- Control Valve,
- Meter,
- Open-Ended Line,

- Pressure Relief Valves and Pressure Safety Valves (PRV/PSV),
- Pump Seal,
- Regulator,
- Thief Hatch, and
- Valve.

The thief hatch component type was added because their emission release characteristics are poorly represented by other component types. It was observed that the leaker and population leak factors differed significantly from connectors and OELs resulting in the creation of a separate component category. This component type may not be considered in other, similar studies. Historically, thief hatches were counted as a valve or a PRV. Because the leaker and population leak factors presented below for thief hatches are different than connectors and OELs (excessive pneumatic venting), separate components types are justifiable.

Gas component services included fuel gas and process gas, but fuel gas is aggregated with process gas. This is consistent with methods used in other fugitive emission factor studies.[28] Average (mean) component counts are calculated for each process equipment type using Equation 3 and are presented in Table 9 and Table 10.

Equation 3,

$$\bar{N}_{CC} = N_{CC}/N_{\mathrm{F/W}}$$

Where,

$\bar{N}_{CC}$ = average component count for a given facility subtype or well status,

N_{CC} = total number of components for a given facility subtype or well status (Clearstone 2018 or field survey),

$N_{F/W}$ = total number of a given facility subtype or well status surveyed.

Clearstone 2018 provides ranges for confidence intervals for their average components per major equipment type calculations, which are particularly wide for major equipment with few sample sizes. Some major equipment component counts, such as catalytic heaters (650 observed in Clearstone 2018), have tight confidence intervals ranging from 7-29% and 8-32% for lower and upper confidence intervals of multiple component types. These tighter confidence intervals are due to large sample sizes and less variation in component accounts across all catalytic heaters. However, there are also examples of large confidence intervals such as flare knockout drums (29 observed in Clearstone 2018), which have confidence intervals ranging from 45-100% and 58-308% for lower and upper confidence intervals of multiple component types. Which is a due to a combination of smaller sample sizes and large variability

[28] Update of Fugitive Equipment Leak Emission Factors, CAPP 2014 (https://www.capp.ca/-/media/capp/customer-portal/publications/238773.pdf?modified=20180910181053)

between component counts for individual flare knockout drums. The confidence intervals from the Clearstone study would conceptually carry over to the estimates of component counts for this study.

As an example, current average gas connecter counts for wells (WT, WO, WC) are at 90-135 connectors per well. The factors that went into estimating the connectors for wells from the Clearstone 2018 study and the average major equipment per site classification. In the Clearstone 2018 study, a wellhead (which should be present at every well location) has 44 connectors, and accounts for ~30-40% of total connectors at a well (WT, WO, WC) in this study. Other major equipment that accounts for a significant portion of the average connector count for wells in this study include separators (25-30%), line heaters (4-24%), Flare Knockout Drum (16% for WC), and some reciprocating compressors (16% for WT). In the Clearstone 2018 study, there are 2 reciprocating and 3 screw compressors that were determined to be located on well sites for comparison. Clearstone 2018 surveyed 440 unique wells. This suggests that outliers may have significant impacts on average component calculations and qualitatively confirms the wide confidence intervals determined by others.

Table 9: Average Component Counts for Site Classifications

	Site Classification (Number of Sites Surveyed)											
Average Component Counts	**WT (123)**	**WO (31)**	**WC (51)**	**SWBT (3)**	**SWBO (7)**	**SWBC (4)**	**MPBO (7)**	**MGBT (15)**	**MGBO (4)**	**MGBC (2)**	**MEMT (12)**	**MEMC (7)**
Compressor Seal Process Gas	0.121				0.533		3.984	3.274			6.940	5.154
Connector Fuel Gas	0.014	0.003	0.015	0.021	0.016	5.958	0.016	11.158	0.016	0.016	0.318	6.848
Connector Light Liquid	33.551	87.356	43.051	58.709	156.122	149.706	896.869	353.374	166.894	37.203	427.718	263.286
Connector Process Gas	128.750	94.786	136.466	207.814	307.817	397.255	1730.206	1,230.841	378.599	119.572	2,075.041	1,323.392
Control Valve Fuel Gas						0.042		0.033				0.048
Control Valve Light Liquid	0.389	0.469	0.667	0.708	1.340	1.270	6.088	3.152	1.119	0.364	4.157	2.697
Control Valve Process Gas	0.451	0.243	0.297	1.078	1.226	2.142	8.988	5.866	2.703	0.672	9.608	5.713
Meter Fuel Gas						0.042		0.033				0.048
Meter Light Liquid	0.152	0.120	0.065	0.180	0.360	0.631	4.742	1.405	0.631	0.210	1.351	1.033
Meter Process Gas	0.498	0.342	0.358	0.731	1.151	2.204	6.278	3.927	2.062	0.813	5.170	3.124
Open-Ended Line Fuel Gas	0.016							0.667			0.500	
Open-Ended Line Light Liquid	0.037	0.132	0.270	0.245	0.645	0.178	2.393	0.773	1.301		1.070	0.017
Open-Ended Line Process Gas	0.111	0.067	0.038	0.447	0.239	0.326	1.764	1.032	0.285	0.104	1.993	1.135
PRV/PSV Fuel Gas	0.008					0.125		0.433			0.250	0.143
PRV/PSV Light Liquid	0.000	0.002	0.000	0.008	0.010	0.003	2.519	0.459	0.018		0.275	0.271
PRV/PSV Process Gas	0.961	0.747	0.611	2.422	2.629	3.960	15.587	10.182	3.323	1.039	15.840	10.074
Pump Seal Light Liquid		0.631	0.021		0.466		3.889	0.767			0.436	0.448
Regulator Fuel Gas	0.117	0.052	0.222	0.382	0.194	0.083		0.749	0.227	0.227	0.437	0.289
Regulator Light Liquid	0.018	0.004		0.040				0.040				
Regulator Process Gas	3.710	2.948	4.868	3.837	7.734	11.473	36.953	24.572	12.551	2.809	49.472	24.608
Thief Hatch Light Liquid	0.013	0.052	0.008	0.267	0.343	0.100	1.429	0.293	0.600		0.667	0.286
Thief Hatch Process Gas	0.008	0.033	0.005	0.173	0.222	0.065	0.924	0.190	0.388		0.431	0.185
Valve Fuel Gas						1.000		2.267				1.143
Valve Light Liquid	6.949	19.933	9.491	11.618	32.151	28.580	189.719	69.018	33.655	7.000	76.025	45.945
Valve Process Gas	27.673	18.226	31.738	25.024	50.185	72.769	223.016	170.630	78.501	30.277	244.432	136.396

Table 10: Total Component Counts for Site Classifications

	Site Classification (Number of Sites Surveyed)											
Total Component Counts	**WT (123)**	**WO (31)**	**WC (51)**	**SWBT (3)**	**SWBO (7)**	**SWBC (4)**	**MPBO (7)**	**MGBT (15)**	**MGBO (4)**	**MGBC (2)**	**MEMT (12)**	**MEMC (7)**
Compressor Seal Process Gas	15				4		28	49			83	36
Connector Fuel Gas	2	0	1	0	0	24	0	167	0	0	4	48
Connector Light Liquid	4,127	2,708	2,196	176	1,093	599	6,278	5,301	668	74	5,133	1,843
Connector Process Gas	15,836	2,938	6,960	623	2,155	1,589	12,111	18,463	1,514	239	24,900	9,264
Control Valve Fuel Gas						0		1				0
Control Valve Light Liquid	48	15	34	2	9	5	43	47	4	1	50	19
Control Valve Process Gas	55	8	15	3	9	9	63	88	11	1	115	40
Meter Fuel Gas						0		1				0
Meter Light Liquid	19	4	3	1	3	3	33	21	3	0	16	7
Meter Process Gas	61	11	18	2	8	9	44	59	8	2	62	22
Open-Ended Line Fuel Gas	2							10			6	
Open-Ended Line Light Liquid	5	4	14	1	5	1	17	12	5		13	0
Open-Ended Line Process Gas	14	2	2	1	2	1	12	15	1	0	24	8
PRV/PSV Fuel Gas	1					1		7			3	1
PRV/PSV Light Liquid	0	0	0	0	0	0	18	7	0		3	2
PRV/PSV Process Gas	118	23	31	7	18	16	109	153	13	2	190	71
Pump Seal Light Liquid		20	1		3		27	12			5	3
Regulator Fuel Gas	14	2	11	1	1	0		11	1	0	5	2
Regulator Light Liquid	2	0		0				1				
Regulator Process Gas	456	91	248	12	54	46	259	369	50	6	594	172
Thief Hatch Light Liquid	2	2	0	1	2	0	10	4	2		8	2
Thief Hatch Process Gas	1	1	0	1	2	0	6	3	2		5	1
Valve Fuel Gas						4		34				8
Valve Light Liquid	855	618	484	35	225	114	1,328	1,035	135	14	912	322
Valve Process Gas	3,404	565	1,619	75	351	291	1,561	2,559	314	61	2,933	955

1.2.3 Pneumatic Devices

1.2.3.1 Pneumatic Device Counts

Pneumatic devices driven by natural gas, propane, instrument air, solar, and electric were inventoried at each location surveyed during the study. 2120 pneumatic devices were observed in the field survey and inventoried, with 725 gas driven pneumatics, 891 instrument air, 419 electric, 11 propane, 59 solar, and 6 were classified as 'other'. Figure 7 below delineates the pneumatic inventory by device type and driver type. The majority (1395 of 2120) of devices are not driven by natural gas and as such will not contribute to site or facility level methane emissions. The pneumatic device types considered are the following:

- Pump,
- Level Controller,
- Transducer,
- Level Switch,
- High Level Shut Down Switch,
- Positioner,
- High Pressure Shut Down Switch,
- Pressure Controller,
- Pressure Switch,
- Plunger Lift Controller,
- Temperature Switch, and
- Other

Figure 7 and Figure 8 presents the distribution of pneumatics by drive and device type. The most common pneumatic device types are pumps, level controllers, and transducers, with a majority of them running on instrument air or electric drives.

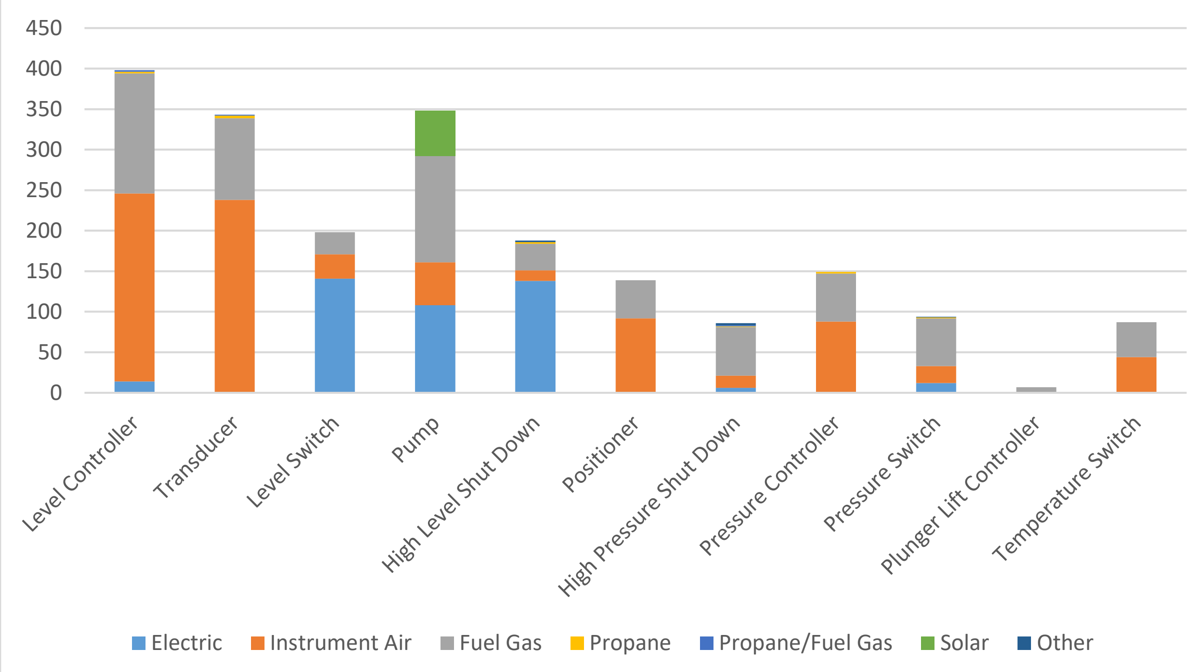

Figure 7: Observed Pneumatic Devices and Equivalents

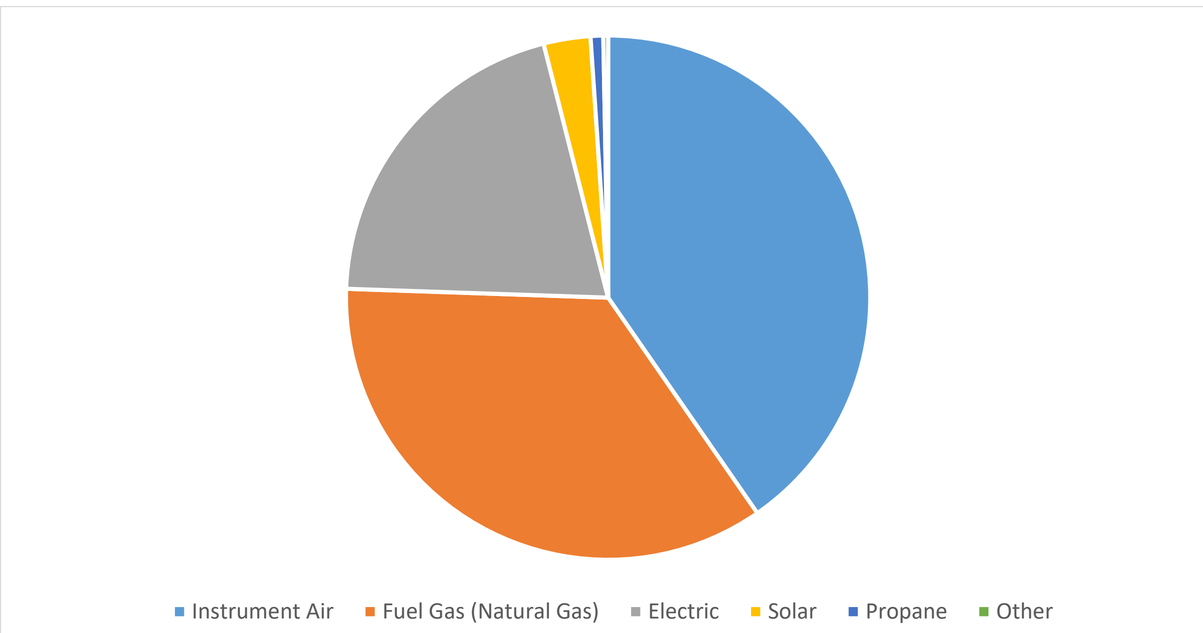

Figure 8: Pneumatic Device Distribution by Drive Type

Table 11 and Table 14 present the average pneumatic devices per site type for all, high bleed gas, low bleed gas, and no bleed (electric, solar, propane, air, other) drive type pneumatics. The majority (65%) of pneumatics are no bleed and are assumed to not emit natural gas from normal operation. For the no bleed pneumatics, 16 were fueled by propane, and are aggregated with no-bleed pneumatics as they would not emit methane. The make and models of all fuel gas pneumatics are included in ***Appendix A: Data Tables***.

High and low bleed designations were based on the vent rate used, and not necessarily manufacturer specifications. The latest studies such as Spartan 2018 re-affirm manufacturer static bleed rates, but quantification of release rates using other than manufacturer specifications was included for completeness and comparison to other studies (see Section 2.1.4).

Table 11: Average Pneumatic Types by Site Classification (All Drives)

	Site Classification (Number of Sites Surveyed)											
Site Average Pneumatic Device Types	**WT (123)**	**WO (31)**	**WC (51)**	**SWBT (3)**	**SWBO (7)**	**SWBC (4)**	**MPBO (7)**	**MGBT (15)**	**MGBO (4)**	**MGBC (2)**	**MEMT (12)**	**MEMC (7)**
Level Controller	0.55	0.32	0.18	1.33	1.43	1.50	8.00	5.60	2.25		9.67	3.71
Transducer	0.49	0.07	0.41	1.67		2.25	5.29	5.53	1.50		6.17	6.43
Level Switch	0.30	0.13	0.24	0.67	0.43	1.50	0.57	2.27	1.00		4.50	5.43
Pump	1.04	0.58	1.57	2.33	1.29	1.25	4.14	4.20	2.00	1.00	4.92	2.14
High Level Shut Down	0.25	0.03	0.18	0.67	0.43	0.25	0.86	3.40			6.67	0.57
Positioner	0.25	0.07	0.12	1.00			2.86	1.93	1.25		2.75	1.43
High Pressure Shut Down	0.10	0.48	0.10	0.67	1.86	0.25	0.71	1.53	0.50		0.33	0.43
Pressure Controller	0.13	0.13	0.10		1.57	0.75	5.71	1.13	1.00		2.67	2.43
Pressure Switch	0.32	0.03	0.57				0.43	1.13			0.25	0.27
Plunger Lift Controller	0.01	0.03	0.06					0.13				
Temperature Switch	0.11	0.03	0.39		0.14	1.25	1.14	0.27			2.00	1.14
Other	0.02	0.07	0.04				0.14					

Table 12: Average High Bleed Pneumatics by Site Classification (Natural Gas Drive Only)

	Site Classification (Number of Sites Surveyed)											
Site Average HB Pneumatics	**WT (123)**	**WO (31)**	**WC (51)**	**SWBT (3)**	**SWBO (7)**	**SWBC (4)**	**MPBO (7)**	**MGBT (15)**	**MGBO (4)**	**MGBC (2)**	**MEMT (12)**	**MEMC (7)**
Level Controller	0.35	0.13	0.12	1.33	0.86		0.57	1.40	0.75			
Transducer	0.29	0.03	0.26	0.33		0.25		0.13	1.25			0.43
Level Switch	0.03			0.33	0.29							
High Level Shut Down	0.02				0.14							
Positioner	0.21	0.03	0.08					0.40				
High Pressure Shut Down												
Pressure Controller	0.12	0.07	0.06		1.43	0.75	0.86	0.60	0.50		0.50	
Pressure Switch												
Plunger Lift Controller												
Temperature Switch												
Other	0.02											

Table 13: Average Low Bleed Pneumatics by Site Classification (Natural Gas Drive Only)

	Site Classification (Number of Sites Surveyed)											
Site Average LB Pneumatics	**WT (123)**	**WO (31)**	**WC (51)**	**SWBT (3)**	**SWBO (7)**	**SWBC (4)**	**MPBO (7)**	**MGBT (15)**	**MGBO (4)**	**MGBC (2)**	**MEMT (12)**	**MEMC (7)**
Level Controller	0.07	0.13	0.04		0.29	0.75	0.29	0.87	0.50		1.00	
Transducer	0.13	0.03	0.08	1.33				0.73				
Level Switch	0.02		0.06			0.25		0.07			0.50	
High Level Shut Down	0.07	0.03	0.16		0.14	0.25	0.14	0.07			0.50	
Positioner												
High Pressure Shut Down	0.07	0.45	0.06	0.67	1.29			0.47				
Pressure Controller												
Pressure Switch	0.28		0.45					0.07				
Plunger Lift Controller												
Temperature Switch	0.11	0.03	0.35		0.14	1.00		0.07				
Other												

Table 14: Average No Bleed Pneumatics by Site Classification

Site Classification (Number of Sites Surveyed)

Site Average NB[29] Pneumatics	WT (123)	WO (31)	WC (51)	SWBT (3)	SWBO (7)	SWBC (4)	MPBO (7)	MGBT (15)	MGBO (4)	MGBC (2)	MEMT (12)	MEMC (7)
Level Controller	0.07	0.13	0.02		0.29	0.75	7.14	3.20	0.75		8.67	3.71
Transducer	0.07	0.03	0.06			2.00	5.14	4.67			6.17	6.00
Level Switch	0.25	0.13	0.10	0.33	0.14	1.00	0.57	2.07	1.00		4.00	5.43
Pump	0.53	0.36	1.14	0.67	0.57	1.00	2.14	1.40	0.75	1.00	2.17	0.86
High Level Shut Down	0.16		0.02	0.67	0.14		0.71	3.20			6.17	0.57
Positioner	0.03		0.02				2.86	1.53	0.25		2.75	1.43
High Pressure Shut Down	0.01	0.03	0.02		0.29		0.29	0.67	0.50		0.33	0.43
Pressure Controller	0.01		0.02		0.14		4.86	0.53	0.50		2.17	2.43
Pressure Switch	0.04	0.03	0.10				0.43	1.07			0.25	0.29
Plunger Lift Controller												
Temperature Switch						0.25	1.14	0.20			2.00	1.14
Other	0.01	0.07					0.14					

Figure 9 compares high and low bleed pneumatics by controller type. High bleed are assumed for pneumatic makes and models with vent rates over 0.17 m^3/hour, with low bleed being below 0.17 m^3/hour. As outlined above, a similar methodology to determine vent rates used in Clearstone 2018 was applied. There are a total of 725 gas-driven pneumatics, with 403 high bleed, 321 low bleed, and one was unknown as the make and model was not discernable.

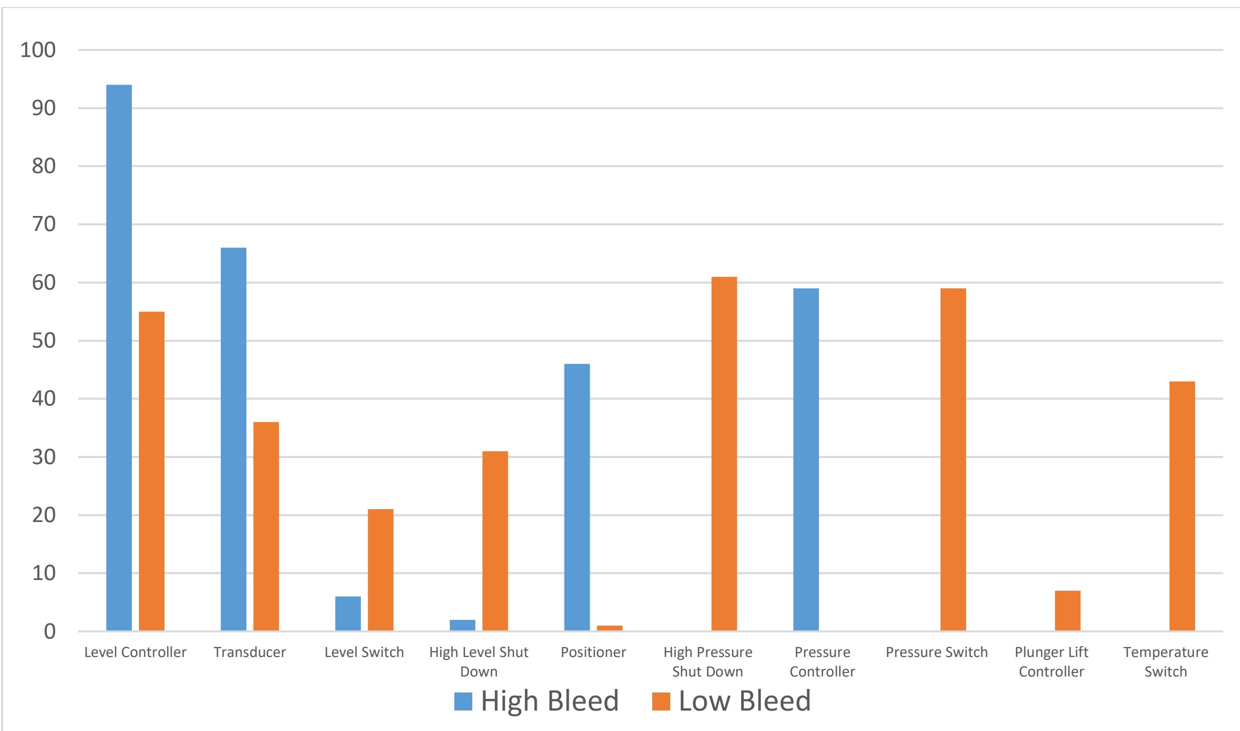

Figure 9: High Bleed and Low Bleed Pneumatics by Control Instrument Type

1.2.3.2 Pneumatics Control Instrument Venting

In this study, vented emissions from pneumatic devices were not measured during the field study. Pneumatic venting was calculated using available literature and publicly available data on normal operational vent rates based on the make and model of the pneumatics which provides a method to

[29] Drive Types: Electric, Solar, Propane, Air

perform site level comparisons. This method is similar compared to other studies such as Clearstone 2018 and Greenpath 2016. There are a wide variety of published pneumatic device vent rates. The pneumatic venting results below are based on the considered sources described in Section 1.1. Only fuel gas pneumatics were assumed to vent methane as part of normal operations. Pneumatic venting rates are summarized below in Table 15 which indicates the weighted average of the estimated vent rates for each type of device and site.

Table 15: Average Natural Gas Pneumatic Device Vent Rates (m^3/hour)

	Site Classification (Number of Sites Surveyed)											
Average Estimated Pneumatic Venting (m^3/hour)	**WT (123)**	**WO (31)**	**WC (51)**	**SWBT (3)**	**SWBO (7)**	**SWBC (4)**	**MPBO (7)**	**MGBT (15)**	**MGBO (4)**	**MGBC (2)**	**MEMT (12)**	**MEMC (7)**
Level Controller	0.21	0.14	0.36	0.26	0.20	0.01	0.18	0.16	0.16		0.01	
Transducer	0.31	0.26	0.47	0.17		0.37	0.14	0.15	0.33			0.51
Level Switch	0.19	0.00	0.10	0.26	0.05	0.09		0.09			0.01	
Pump	0.73	0.71	0.44	0.47	0.77	0.14		0.67	0.61		0.58	0.75
High Level Shut Down	0.03	0.01	0.02		0.05	0.05	0.01	0.09			0.01	
Positioner	0.51	0.40	0.55	0.14				0.54	0.14			
High Pressure Shut Down	0.06	0.06	0.05	0.05	0.06	0.14	0.14	0.09				
Pressure Controller	0.67	0.17	0.58		0.91	1.09	1.53	0.36	0.21		0.21	
Pressure Switch	0.04		0.05					0.02				
Plunger Lift Controller	0.14	0.14	0.14					0.14				
Temperature Switch	0.04	0.04	0.05		0.04	0.04		0.04				
Other	0.14	0.14	0.14									
Overall Average	0.35	0.22	0.24	0.25	0.40	0.27	0.64	0.27	0.30		0.10	0.65

1.2.3.3 Pneumatic Pumps

Table 16 and below present data on average pneumatic pumps per site classification. Due to limitations during the field survey, the chemical injection rates were not available (for example, many inactive pumps during September). The average vent rate for pneumatic pumps was determined in the same method as the other pneumatic devices described in Section 1.1 as no vent rates were measured during the field survey. This was done to facilitate comparison of site level vent rates from pneumatic pumps. The type of chemical injected is available and summarized in Table 17 and Table 18 below by the number of pumps observed per chemical injection and site classification. Chemical type may imply whether pumps are seasonal or continuous, but this was not been quantitatively assessed within the scope of this study.

Table 16: Average Chemical Injection Pumps per Site

	Site Classification (Number of Sites Surveyed)											
Average Pumps per Site	**WT (123)**	**WO (31)**	**WC (51)**	**SWBT (3)**	**SWBO (7)**	**SWBC (4)**	**MPBO (7)**	**MGBT (15)**	**MGBO (4)**	**MGBC (2)**	**MEMT (12)**	**MEMC (7)**
Total Methanol Pumps	0.68	0.19	0.90	1.00	0.86	0.75	0.71	1.00	1.50	0.50	1.00	0.43
Total Other Chemical Pumps	0.33	0.35	0.65	1.33	0.43	0.50	1.43	1.47	0.50	0.50	1.42	1.00
Gas Driven Methanol Pumps	0.28	0.16	0.29	1.00	0.71	0.25		0.60	1.25		0.08	0.29
Gas Driven Other Chemical Pumps	0.20	0.03	0.14	0.67				0.47			0.17	0.29
No Bleed Methanol Pumps	0.40	0.03	0.61		0.14	0.50	0.71	0.40	0.25	0.50	0.92	0.14
No Bleed Other Chemical Pumps	0.13	0.32	0.51	0.67	0.43	0.50	1.43	1.00	0.50	0.50	1.25	0.71

Table 17: Overall Number of Pneumatic Pumps by Chemical Injection Type

Chemical Type Injected	Number of Gas Driven Pumps	Number of Non-Emitting Pumps
Corrosion Inhibitor	20	55
Methanol/Corrosion Inhibitor mix	13	4
Methanol	69	105
Other	23	50
Scale Inhibitor	0	1

Scavenger	2	1

Table 18: Number of Pumps by Chemical Injection Type and Site Classification

Site Classification	Chemical Type Injected	Number of Gas Driven Pumps	Number of Non-Gas Driven Pumps	Average Release Rate of Gas-driven (m^3/hr)
WT	Corrosion inhibitor	10	12	0.80
WT	Methanol/Corrosion Inhibitor mix	6	3	0.67
WT	Methanol	29	46	0.77
WT	No chemical in Tank	0	1	
WT	Other	13	2	0.84
WT	Scale Inhibitor	0	1	
WT	Scavenger	1	0	0.93
WO	Corrosion inhibitor	0	4	
WO	Methanol	5	1	0.90
WO	Other	1	6	0.57
WC	Corrosion inhibitor	5	19	0.62
WC	Methanol/Corrosion Inhibitor mix	3	0	1.02
WC	Methanol	12	31	0.69
WC	Other	2	7	0.80
SWBT	Corrosion inhibitor	0	1	
SWBT	Methanol/Corrosion Inhibitor mix	2	0	0.93
SWBT	Methanol	1	0	0.57
SWBT	Other	2	1	0.98
SWBO	Corrosion inhibitor	0	3	
SWBO	Methanol	5	1	0.75
SWBC	Corrosion inhibitor	0	1	
SWBC	Methanol	1	2	1.02
SWBC	Other	0	1	
MPBO	Methanol	0	5	
MPBO	Other	0	10	
MGBT	Corrosion inhibitor	1	4	0.93
MGBT	Methanol/Corrosion Inhibitor mix	2	0	0.93
MGBT	Methanol	7	6	0.78
MGBT	Other	5	10	0.78
MGBT	Scavenger	1	1	0.57
MGBO	Corrosion inhibitor	0	1	
MGBO	Methanol	5	1	0.75
MGBO	Other	0	1	
MGBC	Corrosion inhibitor	0	1	
MGBC	Methanol/Corrosion Inhibitor mix	0	1	
MEMT	Corrosion inhibitor	2	5	0.78
MEMT	Glycol	0	0	
MEMT	Methanol	1	11	0.57
MEMT	Other	0	10	
MEMC	Corrosion inhibitor	2	4	0.78
MEMC	Methanol	2	1	0.67
MEMC	Other	0	1	

1.2.4 Equipment Fugitive Emissions

In the data received from the field survey, all detected methane emissions (excluding normal pneumatic operation) were classified into two categories; leaks (equipment fugitive sources) and vents (venting sources). In the field survey, 284 leaks were detected and quantified.

A summary of the equipment fugitives detected and quantified at different site types is outlined in Table 19.

Table 19: Equipment Fugitives Summary by Site Type

Site Class-ification	Number of Sites Visited	Sites with one or more leaks	Average Leak Rate (Leaker Population)	Average Leak Rate (General Population)	Main Contributor to Leak Rate	Most Common Leak Type
		(%)	(m3/day/site)			
WT	**123**	17%	8.98	1.54	Open-ended Lines (Excessive Pneumatic Venting)	Connectors
WO	**31**	39%	8.39	3.25	Thief Hatches	Connectors
WC	**51**	55%	5.41	2.97	Valves	Connectors
SWBT	**3**	67%	29.86	19.91	Valves	Valves and Open-ended Lines (Excessive Pneumatic Venting)
SWBO	**7**	57%	13.66	7.81	Open-ended Lines (Excessive Pneumatic Venting)	Open-ended Lines (Excessive Pneumatic Venting), Connectors, and Valves
SWBC	**4**	75%	6.93	5.20	Valves	Valves
MPBO	**7**	71%	32.86	23.47	Thief Hatches	Valves and Connectors
MGBT	**15**	67%	19.65	13.10	Open-ended Lines (Excessive Pneumatic Venting)	Connectors
MGBO	**4**	25%	17.33	4.33	Open-ended Lines (Excessive Pneumatic Venting)	Open-ended Lines (Excessive Pneumatic Venting) and Connectors
MGBC	**2**	0%	0.00	0.00		
MEMT	**12**	83%	32.56	27.14	Connectors	Connectors

Site Class-ification	Number of Sites Visited	Sites with one or more leaks	Average Leak Rate (Leaker Population)	Average Leak Rate (General Population)	Main Contributor to Leak Rate	Most Common Leak Type
		(%)	(m3/day/site)			
MEMC	**7**	71%	19.03	13.60	Connectors	Connectors

1.2.4.1 Leak Distribution

Figure 10 presents the number of leaks detected per site. 165 of the 266 sites surveyed had no leaks detected. And most (88 of 101) of the remaining sites had fewer than 4 leaks per site. 13 sites had 5 or more leaks per site, with 3 sites having more than 10 leaks (11, 11, and 16 leaks for those 3 sites).

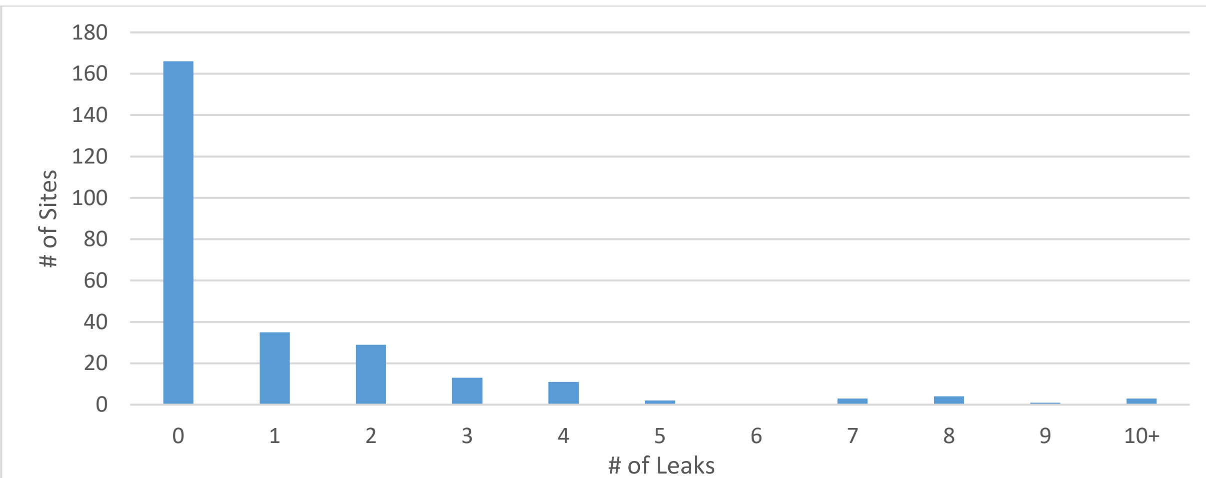

Figure 10: Distribution of leaks observed per facility survey

Figure 11 presents the maximum, minimum, and average leaks detected per site type. The two average bars indicate the average per leaking site and the average per site type overall which includes sites with no leaks. The average amount of leaks per site classification (where leaks are detected) is under 5 for all site types with an overall average of 2.8 leaks per site where leaks are detected, or an overall average of 1.1 leaks per site (includes sites with no leaks detected).

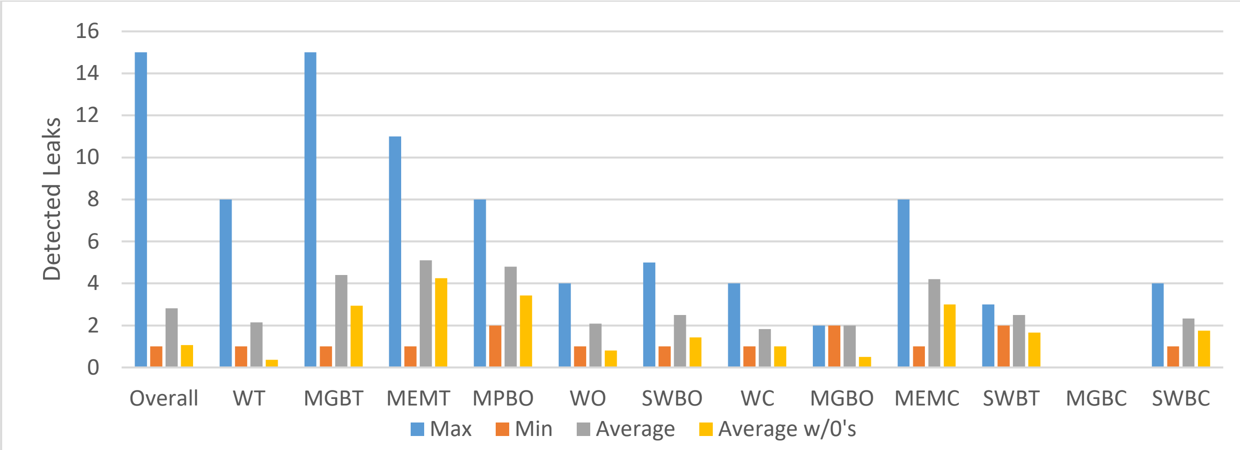

Figure 11: Number of Leaks Detected at Site Classifications (maximum, minimum, average (of non-zero), average (including zeros))

Leak emissions were measured or estimated when observed during the field study as outlined in the field data collection procedures. The volumetric measurements or estimates were recorded along with the ambient conditions. Using the ambient conditions and the volumetric measurements/estimates, a corrected volumetric leak rate was calculated using the combined gas law. Figure 12 below presents the percentage of leaks (by volume) by the number of sources and has been size ordered from greatest volumetric leak sources to least. It is seen that most of the emissions are from a small percentage of sources, 51 and 80 % of emissions from 8.7 and 26.7 % of sources respectively.

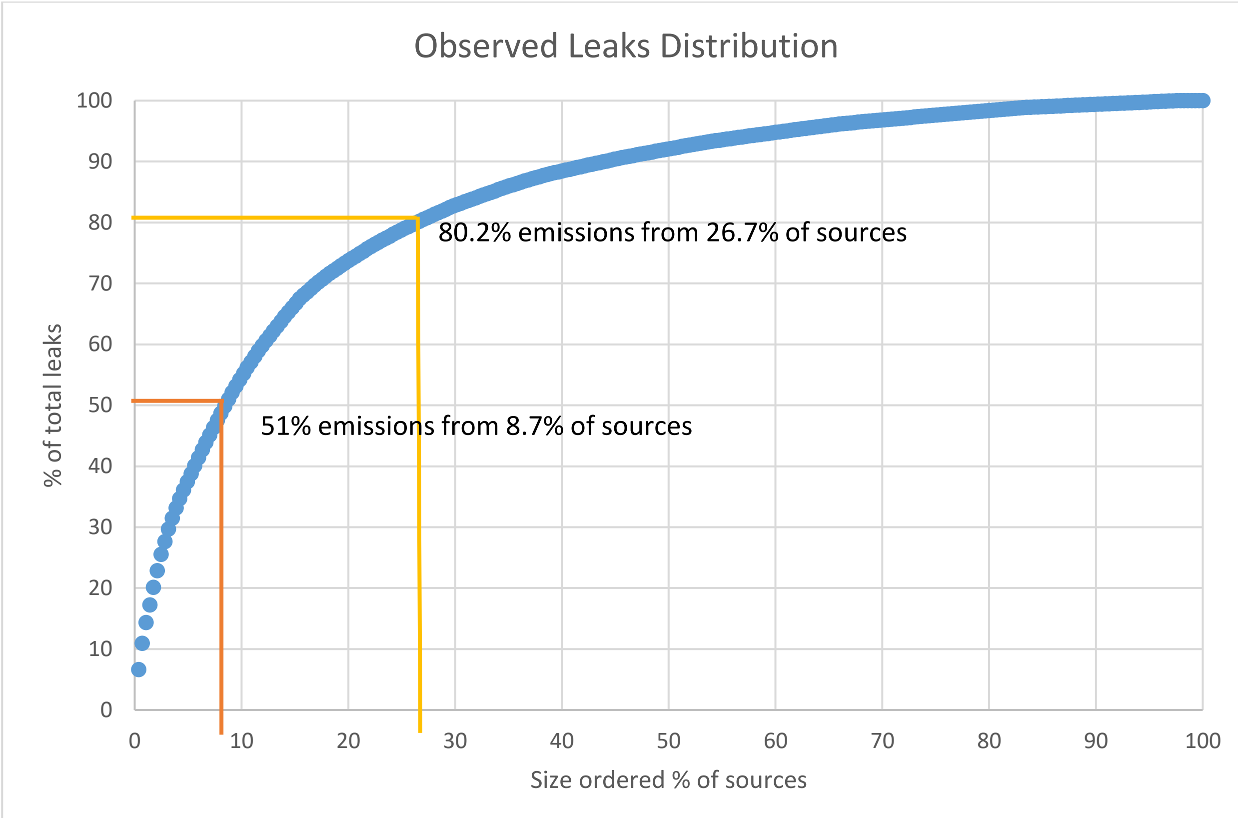

Figure 12: Observed Leak Distribution by Emission Magnitude per Source

Figure 13 below presents leak volumetric data by magnitude of the leak to the overall percentage of leak emissions detected. In the field survey, sources that were not able to be measured due to leak source location were estimated which is differentiated in Figure 13. It is seen that the majority of the larger emissions sources (7 of top 10 sources) were not measured directly as per **Field Data Collection**.

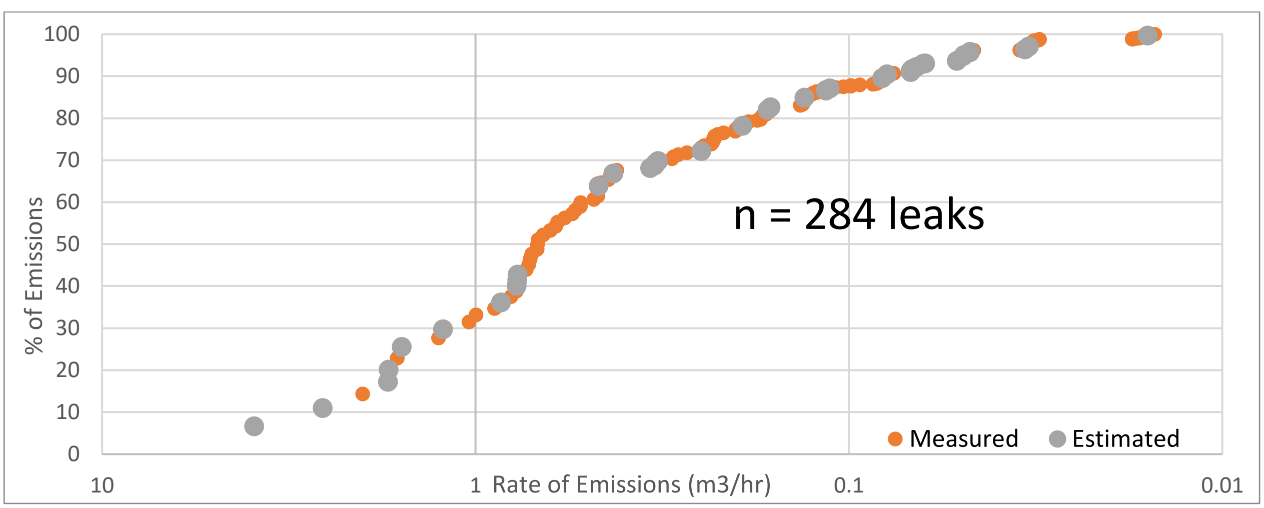

Figure 13: Magnitude of Leak Measurements and Estimates

Table 20 below presents the number of leaks per component type surveyed. There are two types of gas and liquid services (Process Gas & Fuel Gas, Light Liquid & Heavy Liquid although Heavy Liquid was not observed). There were only 4 emissions that were categorized as fuel gas. Therefore, fuel gas and process gas fugitive emissions were combined as 'gas' component service. There was no information collected which could offer insight into sour and sweet gas fugitives as it was out of the scope of the study. No leaks were detected for heavy liquid component service, and therefore all liquid service leaks (only connectors) are in light liquid service.

The leaker factor, total leakage, and average/median leak magnitude are also presented in Table 20. The median is shown to illustrate that the majority of leaks are smaller than the average, but large leaks significantly increase the average leak rate which is shown in Figure 12 and Figure 13. Leaker factor is the ratio of the number of leaks detected over the estimated total amount of the considered component type. An estimated 38% of thief hatches were leaking, whereas all other component types are under 6%, with the lowest leaker factor being .007% (liquid connectors). Thief Hatches also have the highest average, median, and site level leak rates which suggests that Thief Hatches are currently responsible for a significant portion of overall methane leak emissions (3% of overall leak sources, 17% of overall leak emissions).

Table 20: Summary of Leak Field Survey and Results

Component Type	Component Service	Total Components	Number of Leaks	Leaker Factor	Total Leakage (m^3/hr)	Avg Leak rate (m^3/hr)	Median Leak (m^3/hr)
Connector	Gas	96,823	154	0.0016	17.36	0.12	0.05
Connector	Liquid	30,259	2	0.00007	0.24	0.12	0.12
Control Valve	Gas	420	18	0.04	5.64	0.31	0.19
Meter	Gas	307	6	0.02	1.18	0.19	0.03
Excessive Pneumatic Venting	Gas	725	42	0.06	14.06	0.34	0.16
PRV/PSV	Gas	764	2	0.002	1.16	0.58	0.58
Regulator	Gas	2,405	24	0.01	5.16	0.21	0.13
Thief Hatch	Gas	21	8	0.38	9.73	1.22	0.60
Valve	Gas	14,776	22	0.001	2.16	0.10	0.07
Pump Seal	Gas	71	4	0.06	0.42	0.11	0.07

1.2.4.2 Leak Emissions Intensity

Methane emissions from the field survey, other than regular pneumatic operations, are classified as either leaks or vents. The results from the leaks are summarized below in Table 21 classified by component type and component service. Component service has been summarized as either gas or liquid (process and fuel gas are combined as gas; only light liquid component service leaks were observed). Table 22 summarizes the leak rate results into five considered components for time series modeling parameters, the mapping to these five components is displayed in the third column. Table 23 splits the results of Table 22 for each site classification. Confidence intervals were not determined for Table 23 as sample sizes were too small to confidently determine confidence intervals.

Confidence intervals for leaking components were determined using an empirical bootstrap analysis. This analysis is based on the principle that as the sample size increases, the histogram of many samples from a population converges to the probability histogram for that population. Consequently, the confidence interval bands narrow as the sample size increases. In this analysis, we use 10,000 bootstrapped samples (sampling with replacement) to calculate the 95% confidence interval around the sample mean. The results are presented in the tables below.

Table 21: Component Leak Rate Results and Component Mapping

Component Type	Component Service	Modeling Parameter Component Mapping	Total Components	Number of Leaks	Total Leakage (m^3/hr)	Avg Leak rate (m^3/hr)	Median Leak (m^3/hr)	CI Low (2.5th percentile) (m^3/hr)	CI High (97.5th Percentile) (m^3/hr)
Connector	Gas	Connector	96,823	154	17.36	0.12	0.05	0.09	0.16
Connector	Liquid	Connector	30,259	2	0.24	0.12	0.12	0.12	0.13
Control Valve	Gas	Valve	420	18	5.64	0.31	0.19	0.17	0.57
Meter	Gas	Connector	307	6	1.18	0.19	0.03	0.04	0.84
Open-Ended Line*	Gas	Excessive Pneumatic Venting	N/A*	42	14.06	0.34	0.16	0.24	0.49
PRV/PSV	Gas	PRV/PSV	764	2	1.16	0.58	0.58	0.33	0.82
Regulator	Gas	Valve	2,405	24	5.16	0.21	0.13	0.06	0.19
Thief Hatch	Gas	Valve	21	8	9.73	1.22	0.60	0.15	0.33
Valve	Gas	Valve	14,776	22	2.16	0.10	0.07	0.53	2.35
Pump Seal	Gas	Connector	71	4	0.42	0.11	0.07	0.06	0.17

**The Open-Ended Line category was exclusively used to characterize excessive or exceptional pneumatic venting, so calculating the number of components is not meaningful*

Table 22: Component Leak Rate Results – Mapped

Component	Total Components	Number of Leaks	Total Leakage (m^3/hr)	Avg Leak rate (m^3/hr)	Median Leak rate (m^3/hr)	CI Low (2.5%, m^3/hr)	CI High (97.5%, m^3/hr)
Connector	127,502	166	17.93	0.12	0.05	0.09	0.15
Valve	23,948	66	12.17	0.18	0.08	0.14	0.28
Excessive Pneumatic Venting	N/A	42	13.13	0.32	0.15	0.23	0.47
PRV/PSV	794	2	1.08	0.54	0.54	0.32	0.80
Thief Hatch	54	8	9.08	1.14	0.56	0.51	2.26

Table 23: Mapped Component Leak Rate Results by Site Classification

Site Classification	Component Type	Total Components	Number of Leaks	Total Leakage (m^3/hr)	Avg Leak Rate (m^3/hr)	Median Leak (m^3/hr)
WT	Compressor Seal	14.9	0			
	Connector	15,899.2	24	1.38	0.06	0.05
	Valve	3,459.2	8	0.74	0.09	0.07
	Excessive Pneumatic Venting	177.0	13	5.74	0.44	0.45
	PRV/PSV	589.9	0			
	Thief Hatch	2.7	0			
WO	Compressor Seal	0.0	0			
	Connector	2,945.2	12	0.74	0.06	0.05
	Valve	572.1	7	0.92	0.13	0.03
	Excessive Pneumatic Venting	13.0	4	0.47	0.12	0.02
	PRV/PSV	115.9	0			
	Thief Hatch	2.0	2	2.07	1.03	1.03
WC	Compressor Seal	0.0	0			
	Connector	6,978.8	33	2.50	0.08	0.07
	Valve	1,633.8	15	2.65	0.17	0.07
	Excessive Pneumatic Venting	36.0	3	1.16	0.39	0.44
	PRV/PSV	290.7	0			
	Thief Hatch	0.7	0			

Site Classification	Component Type	Total Components	Number of Leaks	Total Leakage (m^3/hr)	Avg Leak Rate (m^3/hr)	Median Leak (m^3/hr)
SWBT	Compressor Seal	0.0	0			
	Connector	625.7	1	0.05	0.05	0.05
	Valve	78.3	2	1.74	0.87	0.87
	Excessive Pneumatic Venting	8.0	2	0.70	0.35	0.35
	PRV/PSV	19.9	0			
	Thief Hatch	1.3	0			
SWBO	Compressor Seal	3.7	0			
	Connector	2,162.8	3	0.73	0.24	0.13
	Valve	359.9	3	0.37	0.13	0.08
	Excessive Pneumatic Venting	20.0	3	0.85	0.28	0.16
	PRV/PSV	73.9	0			
	Thief Hatch	4.0	1	0.32	0.32	0.32
SWBC	Compressor Seal	0.0	0			
	Connector	1,621.8	1	0.11	0.11	0.11
	Valve	303.8	6	0.75	0.13	0.03
	Excessive Pneumatic Venting	4.0	0			
	PRV/PSV	62.6	0			
	Thief Hatch	0.7	0			
MPBO	Compressor Seal	27.9	0			
	Connector	12,147.6	7	0.53	0.08	0.05
	Valve	1,623.1	7	1.31	0.18	0.03
	Excessive Pneumatic Venting	10.0	4	0.30	0.08	0.06
	PRV/PSV	367.3	2	1.16	0.58	0.58
	Thief Hatch	15.3	4	3.55	0.89	0.48
MGBT	Compressor Seal	49.1	0			
	Connector	18,689.3	33	2.83	0.09	0.02
	Valve	2,681.9	4	1.93	0.48	0.53
	Excessive Pneumatic Venting	49.0	7	3.42	0.49	0.19
	PRV/PSV	539.1	0			
	Thief Hatch	7.3	0			
MGBO	Compressor Seal	0.0	0			
	Connector	1,518.8	1	0.03	0.03	0.03
	Valve	324.4	0			

Site Classification	Component Type	Total Components	Number of Leaks	Total Leakage (m^3/hr)	Avg Leak Rate (m^3/hr)	Median Leak (m^3/hr)
	Excessive Pneumatic Venting	13.0	1	0.69	0.69	0.69
	PRV/PSV	64.2	0			
	Thief Hatch	3.3	0			
MGBC	Compressor Seal	0.0	0			
	Connector	240.8	0			
	Valve	61.9	0			
	Excessive Pneumatic Venting	0.0	0			
	PRV/PSV	0.0	0			
	Thief Hatch	0.0	0			
MEMT	Compressor Seal	83.3	0			
	Connector	24,966.2	38	8.34	0.22	0.06
	Valve	3,048.4	7	0.69	0.10	0.11
	Excessive Pneumatic Venting	8.0	4	0.64	0.16	0.16
	PRV/PSV	792.0	0			
	Thief Hatch	13.3	1	3.79	3.79	3.79
MEMC	Compressor Seal	36.1	0			
	Connector	9,333.8	13	1.94	0.14	0.06
	Valve	1,003.1	7	1.93	0.28	0.24
	Excessive Pneumatic Venting	7.0	1	0.10	0.10	0.10
	PRV/PSV	245.8	0			
	Thief Hatch	3.3	0			

1.2.4.3 Dehydrator Leaks

18 leaks from glycol dehydration systems were observed during the survey (and one vent, see Section 1.2.5.4). The composition of glycol dehydrator gas release is unknown and may include increased concentrations of non-methane gas. Dehydrator leaks originated from two component types, connectors and valves (8 valve, 10 connector sources) and are summarized in Table 24.

Table 24: Dehydrator Leaking Summary

m^3/hour	Total Equipment Count	Number of Leaks	Total Leak Rate	Average leak Rate	Average Leak rate for total population
Dehydrator - Glycol	29	18	2.76	0.153	0.095

1.2.5 Vents

Venting emissions, along with leaks, were measured or estimated during the field survey. 101 vents were measured/estimated during the survey and originate from 4 component types (Open-Ended Line Gas + Liquid service, Thief Hatch, and Compressor Seals), compared to the 10 component types logged for leaks.

1.2.5.1 Vent Distribution

Figure 14 below presents the number of sites with how many vents were detected and measured/estimated excluding normal pneumatic venting. The vast majority of sites (185 of 266 sites visited) had no vents detected excluding pneumatics, with 67 sites having a single vent detected and the remaining having 2-5 vents per site.

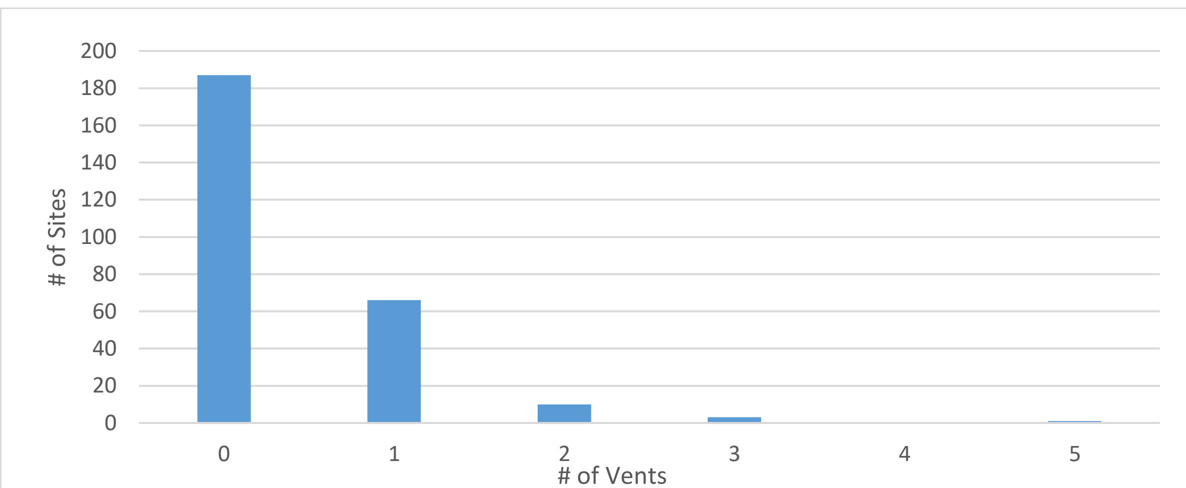

Figure 14: Number of Sites with Number of Detected Vents

Figure 15 below presents the maximum, minimum, average, and average with no detected vent sites included. The overall results are similar to those in Figure 11 for Leaks. It is seen that compared to leaks, most site types had fewer vents across the board, with the maximum vents at a single site being 5.

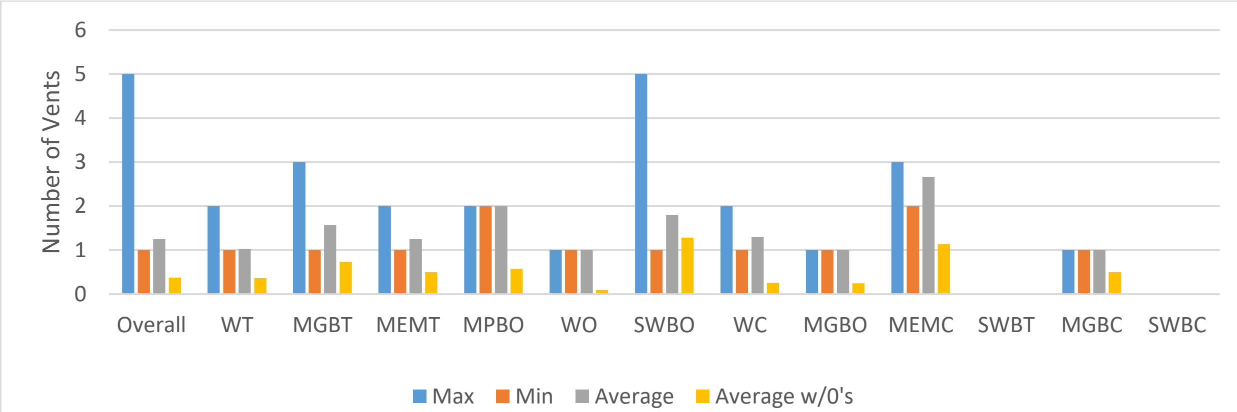

Figure 15: Number of Observed Vents

The source of vents is summarized by major equipment in Figure 16. Four major equipment types (Light Liquid and Water Production Tanks, Reciprocating Compressor, and Gas Flow Wellheads (Surface Casing Vents)) are responsible for ~94% of overall venting emissions with Tanks being the largest major equipment emitter (at 65% of total venting emissions, 25% of which were from Water Production Tanks). All other major equipment that perform regular venting that were captured during the survey did not contribute significantly to overall venting emissions. What is not reflected in this data are operations that release methane episodically unless an episodic release was occurring during the survey. Episodic methane venting emissions by nature are not continuous, and difficult to measure and quantify through surveys such as the one performed in this study as they are snapshots at a point in time, not continuous monitoring.

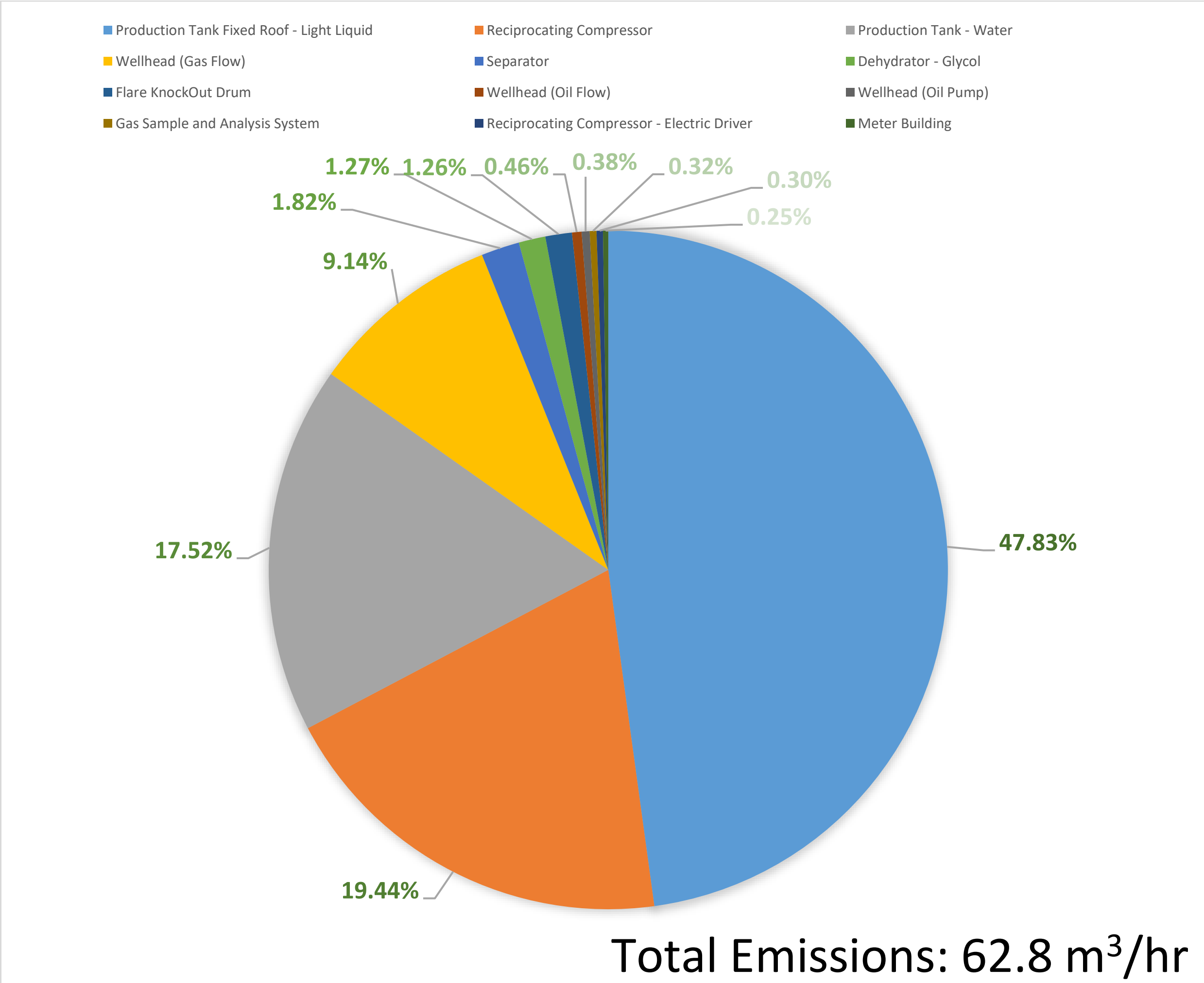

Figure 16: Venting Emissions by Major Equipment Source

1.2.5.2 Tank Venting

Tanks were one of the largest individual sources of emissions that were detected during the MEFS field survey, with a total of 12 vents and 12 leaks detected. 6 of these vents, from Light Liquid Tanks, accounted for nearly 48% of the total observed vented emissions across all sites, and the other 6 vents were observed from Produced Water Tanks. Venting from Produced Water Tanks was confirmed to be hydrocarbon and not steam, but gas compositions were not assessed during the study. CAPP (2005)[30] suggests negligible hydrocarbon emissions from Produced Water Tanks so further study may be required to determine or update gas composition from these sources. The summary of the tank venting and leaking is summarized in Table 25 and Table 26 below. The observed tank vents are uncontrolled and the observed tank fugitives

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[30] A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 3 Methodology for Greenhouse Gases, CAPP, 2005 (Available at https://www.capp.ca/publications-and-statistics/publications/86223)

are from controlled tanks. Of the 12 leaks detected, 8 were from thief hatches, with 2 from PRV/PSV and 2 from connectors.

Table 25: Tank Venting Results

m^3/hour	Total Equipment Count	Number of Vents	Total Vent Rate	Average Vent Rate per Source	Average Vent Rate for Total Equipment Population
Production Tank Fixed Roof - Light Liquid	85	6	29.99	45.00	0.35
Production Tank - Water	90	6	10.98	1.83	0.12

Table 26: Tank Leaks Summary

m^3/hour	Total Equipment Count	Number of Leaks	Total Leak Rate	Average Leak Rate per Source	Average Leak Rate for Total Equipment Population
Production Tank Fixed Roof - Light Liquid	85	12	11.12	0.93	0.13

1.2.5.3 Compressor Seal Venting

There were 18 instances of compressor seal venting that were observed during the study. The vent rate and source of these vents are summarized in Table 27 and

Table 28 below. Table 27 presents the overall vent rate averages and median in m^3/hr of gas.

Table 28 presents the amount of each type of compressor at the site classifications, along with how many vents were observed to be tied to flare.

Table 27: Compressor Seal Vent Rate Results

	Component Service	Total Compressors	Total Compressor Seal Components	# of Vents	Total Vent Rate	Average Vent Rate (per Vent)	Average Vent Rate Per Compressor	Median Vent Rate (Of Sources)
Compressor Seal	Gas	69	215	18	12.25	0.68	0.18	0.17

Table 28: Compressor Count and Compressor Vent Controls by Site Classification

	Site Classification (Number of Sites Surveyed)												
Total Compressors (Compressors Tied into Flare) by Type	**WT**	**WO**	**WC**	**SWBT**	**SWBO**	**SWBC**	**MPBO**	**MGBT**	**MGBO**	**MGBC**	**MEMT**	**MEMC**	**Total**
Reciprocating Compressor	4				1		6(1)	10 (5)			22 (8)	9	52
Screw Compressor - Electric Driver							5 (1)	3			2		10
Reciprocating Compressor - Electric Driver							1	4 (1)				1 (1)	6
Screw Compressor				1									1

1.2.5.4 Dehydrator Vents

Only a single instance of dehydrator venting was captured during the MEFS field survey. Table 29 summarizes the results from Dehydrator venting. The composition of glycol dehydrator gas release is unknown and may include increased concentrations of non-methane gas. The single vent case component source was an OEL.

Table 29: Dehydrator Venting Summary

m³/hour	Total Equipment Count	Vents	Total Vent Rate	Average Vent Rate per Source	Average Vent Rate over Total Equipment Population
Dehydrator - Glycol	29	1	0.797	0.797	0.027

1.3 Chapter 1 Summary

Upstream oil and gas wells and batteries in BC share certain characteristics with other jurisdictions, including the most common methane emission sources in pneumatic control instruments, chemical injection pumps, tanks and compressors. As has been found elsewhere, the distribution of methane emissions among BC operations is highly skewed, with small numbers of sources contributing a large proportion of total emissions and wide confidence intervals on average values.

For a variety of potential reasons, BC operations also exhibit particular unique characteristics including a significant population of non-emitting process control and chemical injection equipment. Routine venting does not appear to occur at most wells and batteries in BC.

Chapter 2: Comparison to Contemporary Studies

Comparing emissions across components and equipment between different studies is difficult for two main reasons. First, survey practices and operators use different definitions and categorization of components that are not standardized across studies. Second, source detection technologies exhibit significant performance variations based on weather conditions and operator expertise. Studies done with the same technology but under varying seasonal weather will exhibit different leak-size distributions.

Due to methodological similarities a comparison to Clearstone 2018 is more adjacent than some other studies. Total natural gas released from all sources in that study comprised 33% pneumatics, 28% from production tanks, 20% from equipment fugitives, and 16% from heavy oil well casing vents in Alberta. This compares with the results of this study corresponding to 66% from pneumatics, 15% from production tanks,[31] and 17% from other equipment fugitives. Note: the remaining emissions were from other sources (e.g. non-tank venting).

2.1.1 Estimated Pneumatic Venting Emissions

Figure 17 shows the device-level emissions in this study (red) compared to the Greenpath 2016[32] study (blue). While most vented emissions are similar, two components stand out – the pressure controller where BC has almost double the emissions of AB, and pump-related emissions where BC has 40% lower emissions than AB. In addition, many pneumatic device types in AB were assumed to emit “significantly lower” than 0.17 m^3/hr, while the BC data implies that these small sources can have non-trivial emissions (e.g., plunger lift controllers).

[31] 15% comprises 9% venting from light liquids tanks, 3% venting from produced water tanks, and 3% tank fugitives.
[32] Greenpath 2016 Alberta Fugitive and Vented Emissions Inventory Study, Greenpath Energy, 2016 (Available at https://www.aer.ca/documents/GreenPathAER%20Survey-Methane.pdf)

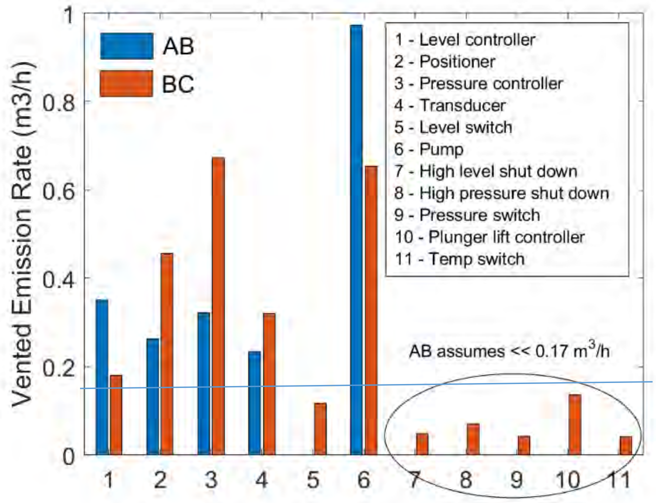


Figure 17: Comparison of vented emissions between this study (red) and Greenpath 2016 study in AB (blue).

2.1.2 Fugitive Emissions

Leaks or fugitive emissions exhibit varied behavior. Across all component types analyzed, BC emissions are uniformly lower than AB emissions. However, it should be noted that fugitive emissions that were unable to be measured directly were estimated, which can lead to significant discrepancies in total emissions measurements. This is mitigated to the extent possible by the fact that the same contractor (Greenpath Energy) conducted both surveys and employed the same estimation methodology.

Furthermore, the error bars for each component-level emissions source is large (2 – 3x the measured emissions) because of two reasons – (a) the sample size is typically small, and (b) total emissions are dominated by a few very large emitters, resulting in a larger upper bound on the estimates.

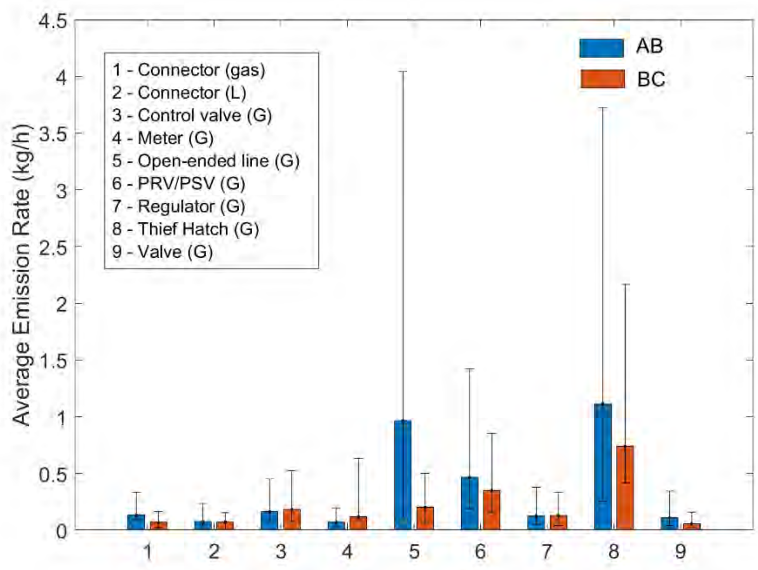


Figure 18: Comparison of fugitive emissions between this study (red) and Clearstone 2018 study in AB (blue).

2.1.3 Compressor Emissions

There have been many recent studies in the US and Canada that measured emissions associated with compressor stations. While some studies report emissions factors which typically represented population-averaged emissions, others report average emission rate from emitting compressors. Table 30 shows the population-averaged emissions factors comparison from four recent studies. It is important to note that although population averaged emissions factor in the US GHG inventory is similar to that observed during this field campaign, other peer-reviewed study published in the US often show significantly higher emissions (see for e.g., Mitchell et al.).[33] Further research is required to better understand the emission size distributions across compressor emissions.

Compressor emissions from this study are estimated at approximately the same value as EPA GHGI for small reciprocating compressors across a population of nearly 36,000 units.

Table 30: Population-Average Emissions Factor

Study	Region	Equipment type	Emission counts	Component Counts	Emissions Factor type	Emissions Factor (kg/h/source)
Clearstone	AB (2018)	RC		139	Population	0.206
Clearstone	AB (2018)	RC	27		Emitting	1.082
EPA GHGI	US (2016)	RC (small)		35930	Population	0.141
EPA GHGI	US (2016)	RC (large)		136	Population	8.099
Mitchell et al[33]	US (2015)	RC	34		Emitting	27.512
Greenpath	AB (2017)	RC		296	Population	2.459

[33] Mitchell et al. (2015) Environ. Sci. Technol. **49** 3219.

BC MEFS	**BC (2019)**	**RC[34]**		**69**	**Population**	**0.14**
BC MEFS	**BC (2019)**	**RC[34]**	**18**		**Emitting**	**0.40**

**RC = Reciprocating Compressors (rod packing)*

2.1.4 Pneumatic Demographics

Figure 19 below presents a comparison of the split between pneumatic device types between the Greenpath study performed in 2016 in Alberta and this survey in BC but excludes the BC pumps count. It is interesting to note that the ratios of each pneumatic device type are different in BC and AB, for example, there are more level controllers in the overall pneumatic device population compared to BC. In the BC study, pneumatic device types in Figure 19 excludes pressure switches (10%), level switches (4.6%), and other unidentified pneumatics (0.7%) as those were not included in Greenpath's 2016 pneumatics classification.

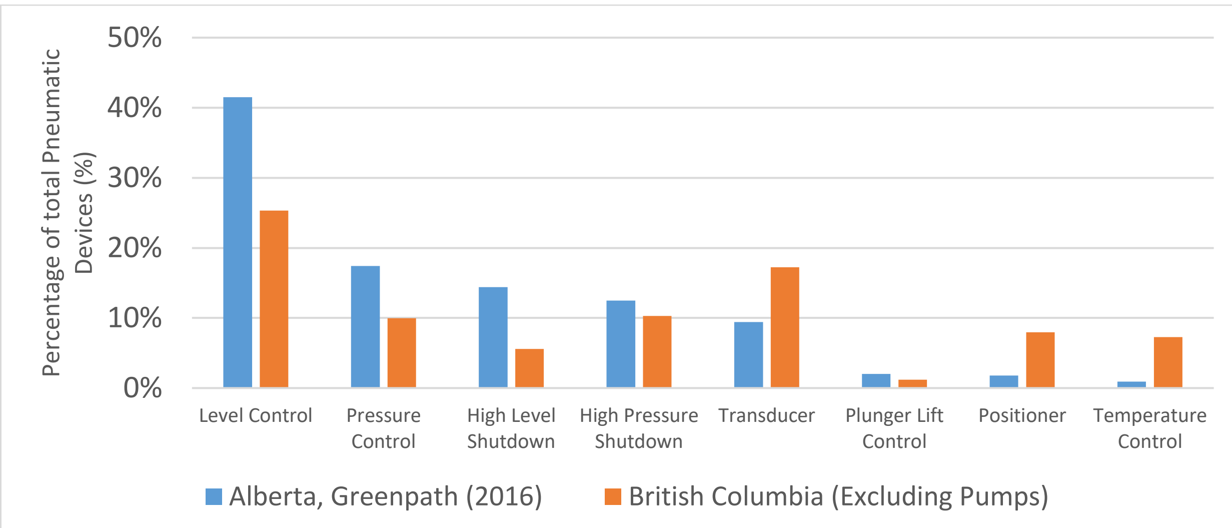


Figure 19: Pneumatic Device Type Ratio Comparison Between Alberta Greenpath Study and BC MEFS

2.2 Chapter 2 Summary

Direct comparison across studies with differing methodologies, timeframes, field teams, and other elements is often difficult. Due to methodological similarities a comparison to Clearstone 2018 is more adjacent than some other studies.

Relative to that study, pneumatic venting was estimated to represent a higher proportion of total venting in BC, despite the prevalence of non-emitting equipment, partly as a result of methodological differences (certain types of gas-driven pneumatic control instruments were assigned vent rates of zero in Clearstone 2018), and partly as a result of some a small number of extremely large emissions from surface casing vent flows and thief hatches. Overall the studies generally agree on the dominant emission sources in upstream oil and gas, with important differences.

[34] Size of compressors was not recorded, assumed to be biased towards smaller equipment since none of the sites surveyed were registered as compressor stations. Note average methane concentration assumed to be 86%.

Fugitive emissions are inherently difficult to compare due to large confidence intervals in most datasets, but again generally agrees across many component types.

Compressor emissions from this study were estimated at approximately the same value as EPA GHGI for small reciprocating compressors across a population of nearly 36,000 units.

Chapter 3: Fugitive and Episodic Emissions Management Practices

In Chapter 1, modeling parameters that could be determined from the field survey data were developed. Supplementing snapshot field observations with historical records was included in the study design in order to support the development and refinement of policy/scenario modeling parameters. Temporal variation and impacts to emission sources over time should be accounted for when parameters are developed. The modeling parameters for certain emission sources can have an explicit temporal component that considers emissions variation over time (e.g. months/years), which would not be observed by the snapshot exercise of field observation.

To obtain these data on longer term variations a voluntary Corporate Data Request (CDR) was prepared for the participating companies to provide historical fugitive emission management data, as well as other types of methane emission information that was not possible to observe while on-site. The data that were received included information on fugitive repair times, fugitive history, and other sources of methane emissions (including information on episodic emissions and emission control systems). This information supplemented the field observations, where applicable, in order to account for temporal variations in modeling parameter development.

The analytical approach largely follows the description in Section 1.1 Analytical Approach, in addition to the descriptions provided herein.

3.1 Leak Repair Times

A total of 11 CDR responses were received which covered 51 of the 266 locations surveyed in this study's survey. A histogram of repair times for leaks is presented in Figure 20. Not all facilities from the CDR included repair times, 12 sites, which represented repair intervals from a total of 36 repairs. The most common timeframe to perform a repair is within 16 days, with the average repair time of the reported facilities at 45 days. The data provided, while it offers insight into timeframe to perform repairs, may not be representative of broader industry practices due to a small sample size and limited information contextualizing the types of repairs required.

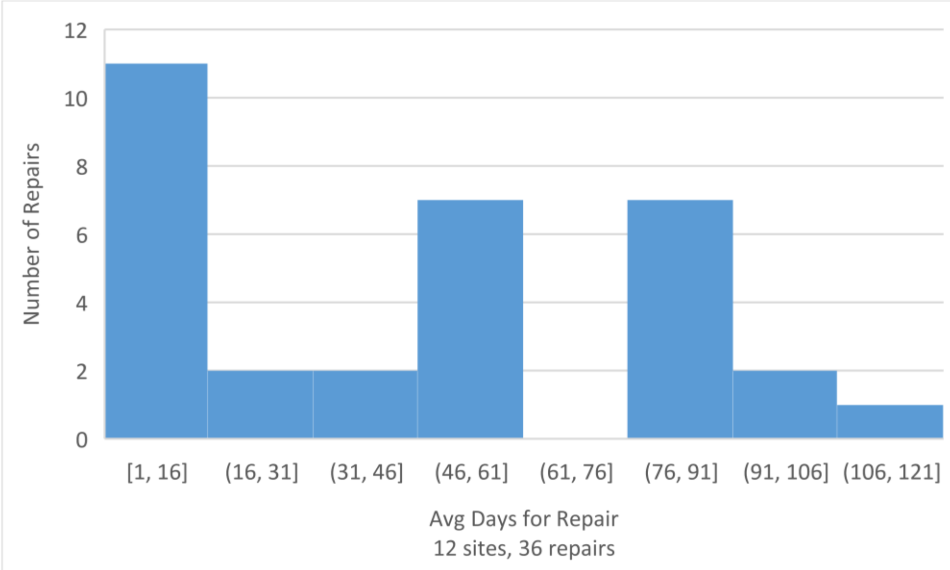


Figure 20: Histogram of Reported Repair Times from CDR

3.2 Leak Occurrence Rate

The leak occurrence rate was calculated based on the facilities that reported a 'last Fugitive Survey' in the CDR. The following equation was used to calculate the leak occurrence rate;

$$\frac{(L_{MEFS} - L_{LL})}{M_{MEFS-LL}}$$

Where,

L_{MEFS} = Number of leaks detected during the MEFS field survey

L_{LL} = Number of leaks detected and not repaired during the previous LDAR survey

$M_{MEFS\text{-}LL}$ = Months between the MEFS field survey and the previous LDAR survey

The results of the leak occurrence rate by facility is presented in Table 31 below. All leaker factors labelled as 'Negative' in Table 31 have a negative leaker factor because the non-repaired leaks from the previous LDAR survey is more than the number of leaks detected during the MEFS field survey. This likely reflects a limitation of the repair information provided. There are 4 instances where the leaker factor is not calculated, and the cell has been left blank. These 4 facilities either performed their "previous" LDAR survey after the MEFS field survey or reported the MEFS field survey as their last LDAR survey.

Table 31: Leak Occurrence Rate based on CDR Reported Facilities

Anonymous Identifier	Facility Type	Leaks from BC MEFS Study	Leaks Detected from CDR Responses	Leaks Repaired from CDR Responses	Leaks Not Repaired from CDR Responses	Months between Last LDAR and BC CAS Survey	Leaker Factor (leaks/month)
188	MPBO	0	0	0	0	2	Negative[35]
252	MPBO	7	2	0	2	23	0.22
55	MEMC	8	7	0	7	0	
125	WC	2	0	0	0	24	0.08
25	WC	3	0	0	0	23.5	0.13
17	MPBO	3	2	0	2	0.5	2.00
192	MEMT	3	1	0	1	21	0.10
111	MEMC	7	3	0	3	19	0.21
44	MEMT	11	17	0	17	9.5	Negative
72	WC	1	4	0	4	20	Negative
169	WC	0	0	0	0	23.5	Negative
102	MEMC	0	1	0	1	1	Negative
107	MEMT	2	4	4	0	17	0.12
152	MEMT	4	4	3	1	0	
14	MEMT	5	4	4	0	7	0.71
15	MEMT	11	7	0	7	1	4.00
69	MEMT	6	4	0	4	13	0.15
143	MGBT	1	2	2	0	9	0.11
145	MGBT	1	2	2	0	18	0.06
245	MEMT	1	4	0	4	23	Negative
71	MEMT	3	1	0	1	1	2.000
162	MGBT	2	4	3	1	0	
253	WC	0	0	0	0	25	Negative
80	WC	4	0	0	0	24	0.17
167	WC	2	0	0	0	26	0.08
86	WC	2	0	0	0	26	0.08
172	WC	3	1	0	1	24	0.08
88	WC	1	1	0	1	23	Negative
33	MGBO	0	7	7	0	7	Negative
224	MGBT	2	3	2	1	5	0.20
165	SWBO	2	7	4	3	7	Negative
178	MGBT	4	3	3	0	2	2.00
133	WT	0	6	1	5	21	Negative
186	WT	1	5	5	0	7	0.14
225	WC	0	0	0	0	25	Negative
45	WT	1	1	1	0	7	0.14
6	MGBC	0	1	0	1	22	Negative
42	SWBT	0	0	0	0	23.5	Negative
240	WT	0	1	1	0	17	Negative
103	WT	3	0	0	0	23	0.13
249	WT	0	2	2	0	7	Negative
223	WT	0	9	7	2	5	Negative
190	WT	0	1	0	1	18	Negative
251	WT	3	3	3	0	0	

Generally, component-specific detail was not provided but if we assume that all leaks from the previous LDAR survey to the MEFS survey are repaired, it is possible to calculate a leak occurrence rate based on

[35] Indicates likely repair data gap – number of unrepaired leaks from prior survey higher than observed number of leaks in subsequent (MEFS) survey

the equation below by component type, as those data are available from the MEFS survey.[36] A leak occurrence rate for PRV/PSV's was not able to be calculated as no leaks were detected during the MEFS field survey at the 51 facilities that provided CDR responses.

Equation 4,

$$Leak\ Occurence\ Rate_{by\ component\ type} = \frac{\sum_{i=1}^{N}\left(Cl_i - Cl_{i,t-1}\right)/M_i}{\sum_{i=1}^{N} Ct_i}$$

Where,

Cl_i = are the number of leaking components by type detected from the i^th facility inspection,
$Cl_{i,t-1}$ = are the number leaks detected but not repaired from the inspection previous to the i^th facility inspection. Note: $\left(Cl_i - Cl_{i,t-1}\right)$>=0,
M_i = is the number of months since the last inspection from the i^th facility,
Ct_i = is the total number of components by type at the i^th facility, and
N = is the total number of facilities for which field study data is available.

The leak occurrence factors by each component type are presented in Table 32 below. The calculation assumes that $Cl_{i,t-1}$ is equal to 0 (all previously detected repairs were repaired) to be able to calculate a leak occurrence rate with the available responses. The sample size is also provided for context.

*Table 32: Leak Occurrence Rate by Component Type**

	Thief Hatch	PRV/PSV	Valve	Connector	Excessive Pneumatic Venting (Previously OELs)
Leaker Factor (Leaks/Month)	0.0115	0	0.0013	0.0004	0.0064
Sample Size (# of leaks used for calculation)	4	0	16	67	5

**These results assume that all leaks from the previous LDAR survey to the MEFS survey are repaired and that all detected leaks during the MEFS survey are new.*

3.3 Other Sources and Controls

In Cap-Op's 2017 report *Other Sources of Methane Emissions in the Oil and Gas Sector* a number of less significant methane sources were identified.[37] The CDR included information on these, including episodic emissions such as depressure events and compressor gas starts, as well as information regarding emission control systems associated with these events. Very few responses provided information so these data are summarized at a very high level as follows:

- More compressor gas start systems were controlled than not
  - Control via tie-in to flare, air-start (instrument air) or electric drive
- Wide variability in number of compressor starts per year
- More dehydrators were controlled than not
  - Control via flare, vapor recovery unit

[36] This assumption is supported by the company reported information as it typically reported the same number of leaks detected as leaks repaired, when information was available, however these data represent a very small subset of the study sites.
[37] Other Sources of Methane Emissions in the Oil and Gas Sector, Cap-Op Energy, 2017. Available by request from ECCC or Cap-Op Energy.

- More depressure events were controlled than not
    - Control via flare
- Average reported volume per depressure event was less than 10 m^3/event

3.4 Chapter 3 Summary

Obtaining highly specific historical data on fugitive and episodic emissions is influenced by a number of factors including a wide variety of emission management practices and reporting systems. By matching voluntarily provided corporate historical data with field observations a high-level characterization of the performance of fugitive emissions management at specific sites can be understood over time. Understanding episodic emissions and the different ways they are being managed by companies provides an additional layer of context for time-series modeling.

Chapter 4: Long Term Methane Emission Drivers

Note: All results are based on discussions from the workshop participants as Cap-Op and DXD intentionally assumed an objective, observational role in the working discussions. Cap-Op and DXD input to the sessions was limited to clarification, facilitation and guidance.

4.1 Temporal State Definition

4.1.1 Distant Past

The distant past temporal state was defined as pre-2009 and, importantly, this was effectively prior to the current level of greenhouse gas reporting in British Columbia. Participants broadly viewed this period as the “single well pad era” and agreed that production in British Columbia was dominated by single-well oil and gas production. While some groups accounted for production in the 1980s and 1990s, others provided their experience from the 2000s. Less pipeline infrastructure was in place and conventional production (without hydraulic fracturing) was most common. This period was also characterized by appraisal and exploration of the natural fields in British Columbia (especially the Horn and Montney basins). While individual companies may have piloted certain methane abatement technologies and CAPP Best Management Practice for Fugitive Emissions Management (CAPP BMP)[38] was beginning to be used (around 2007), focused attention to methane management across industry was limited. Sour gas management and facilities design, not methane emissions awareness, drove conservation behaviour that may have otherwise been absent in sweet gas regions. Production was driven by economics and basic compliance with the regulations of the day. This was noted in slight contrast to current conditions, where more comprehensive consideration is also given to regulations, emissions, climate change and social factors that may have a future impact on operations. Participants agreed that the regulatory environment was very different than the one observed in today’s production. Dry gas, not wet gas, was the dominant product and, relative to today, more field compression and less processing occurred. It was also noted that some drivers may have counter-balanced influence, for example the prevalence of single-well pads would drive up equipment to facilities ratios but lower numbers of processing facilities and gas plants in the field would drive ratios down.

[38] Best Management Practice for Fugitive Emissions Management, CAPP, 2007. Available at https://www.capp.ca/publications-and-statistics/publications/116116

4.1.2 Recent Past

The recent past temporal state was defined as the period from 2010 to 2015. This period was marked by a shift from dry gas to liquids rich gas and the development of the Montney. Horizontal drilling technology had significantly improved, and very little conventional drilling was occurring. This period, referred to as the "multi well pad era," also saw dramatic increases in the use of multi-well pads, driving down equipment to facility ratios. Pipeline infrastructure increased to meet development needs and Producers began to pilot programs and design infrastructure to drive efficiencies. In contrast to the distant past, this period saw that factors beyond economics had to be given consideration. Social issues, movements against hydraulic fracturing, environmental activism and climate change began to impact the industry. Leak Detection and Repair (LDAR) had been implemented at some large facilities and some producers had implemented full LDAR programs across their fleets, in part driven by CAPP BMP and other publications. This period was also volatile economically. By 2010/2011, the industry had begun to recover from the global economic crash in the late 2000s and by 2012, the industry in BC was seeing an increase in exploration and drilling. However, 2014 saw another economic downtown in the oil and gas industry of Western Canada that impacted BC producers. Opportunities surrounding coastal liquefied natural gas (LNG) facilities grew and contracted with the market; several proposed LNG projects extended into the current and future time periods.

4.1.3 Future

The future temporal state was defined as a post-methane regulation implementation scenario, between 2020 and 2030, where all producers would be operating to achieve compliance with applicable regulations, and that equivalency of provincial programs has been completed and approved. LNG and the potential growth of the industry associated with it dominates this period. In addition to being a driver for new assets, LNG development could bring legacy assets back online. Producers will continue to maximize the efficiency of multi-well pad design, further decoupling production and footprint. Liquids rich production and horizontal drilling practices are expected to continue, with even better horizontal drilling technology coming online. There is the potential that the Clean Fuel Standard (CFS) may drive the stabilization of domestic demand and the price of natural gas. As producers consistently show proactive compliance with the regulations, the focused interest that Non-Governmental Organizations (NGOs) and governments currently have on methane emissions from oil and gas operations may begin to ease. Additionally, as producers and regulators see full implementation of the regulations, year over year, there is the potential that LDAR requirements may decrease, as more data is available to inform efficient yet effective emissions reductions.

4.2 Assessment of Drivers

Results of the workshop were assessed for each modeling driver. Each group's assessment was plotted over time, showing their interpretation of the directionality and magnitude of change of these drivers for each temporal period.

Issues that make temporal forecasting difficult include acquisitions/sales, as well as change in ownership and working interest partners. In addition to making factors like equipment counts and prevalence of low bleed pneumatics (in other words, physical factors), changes in ownership also generally result in "legacy staff" no longer being associated with sites and facilities. For example, while field assets may be acquired, it is not always the case that the operators working on those sites go with the sale.

4.2.1 Equipment to Facility Ratios

Participants identified multiple factors that impact equipment to facility ratios:

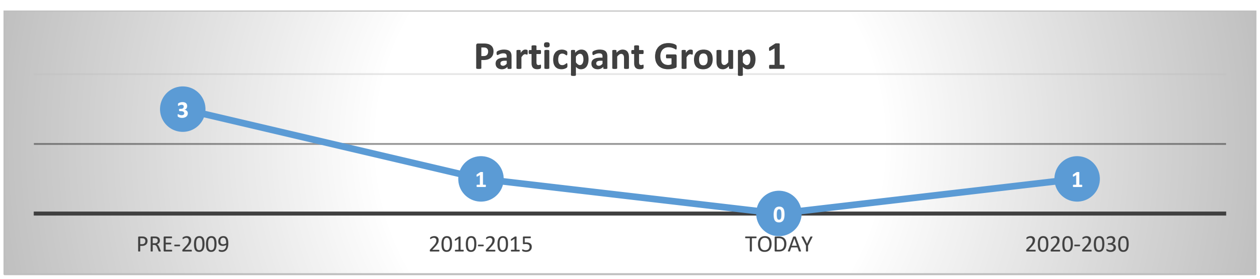
- Level of gas processing required, related to dry gas vs. wet gas;
- Prevalence of gas plant facilities;
- Trend from single-well pads in the past to multi-well pads (i.e., concentration of equipment and/or prevalence of larger pad-level equipment);
- Amount of compression occurring in the field; and
- Fundamentally different equipment for different products (sweet or sour; dry gas or wet gas).

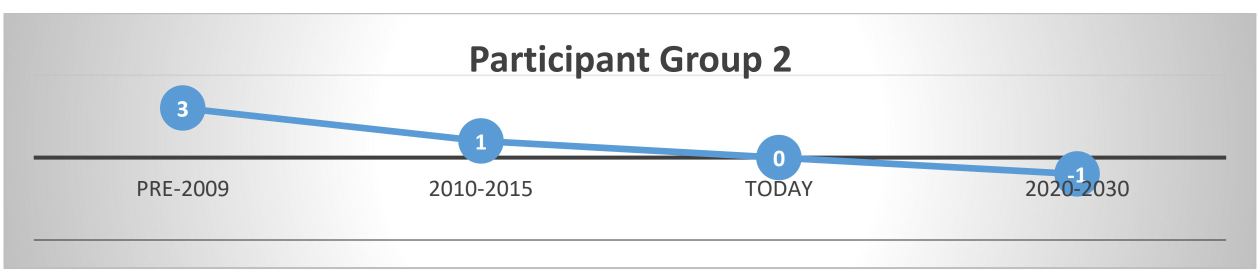
Distant Past: some characteristics of pre-2009 operations would translate to more distinct pieces of equipment, and some would translate to fewer. In general, the consensus was that the dominance of single-well pads meant more equipment in the field, per well pad.

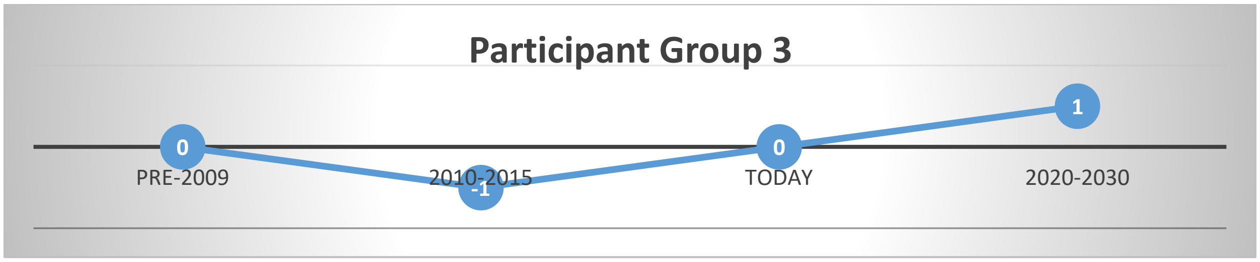
Recent Past: this period saw a concentration of equipment on smaller footprints with the shift to multi-well pads and industry participants generally felt that equipment to facility ratios were lower than the pre-2009 period. However, in general, equipment to facility ratios were higher relative to current operations with a shift to wet gas from dry gas, as field processing facilities became more prevalent.

Future: future operations will continue to see a trend towards centralized facilities, which will result in more and larger equipment per facility, but fewer facilities. If growth is seen due to LNG, absolute amounts of equipment in the field will increase. Electrification (dual feed) will require more processing and abatement equipment. Increased processing and fractionation will result in increased equipment, as more oil and water are handled. On a per-well basis, amount of equipment will decrease; however, more intense processing will result in larger equipment and likely higher equipment ratios.

Workshop consensus on directionality and magnitude of change in the future: ↑ *(1)*







4.2.2 LDAR Inspection Frequency

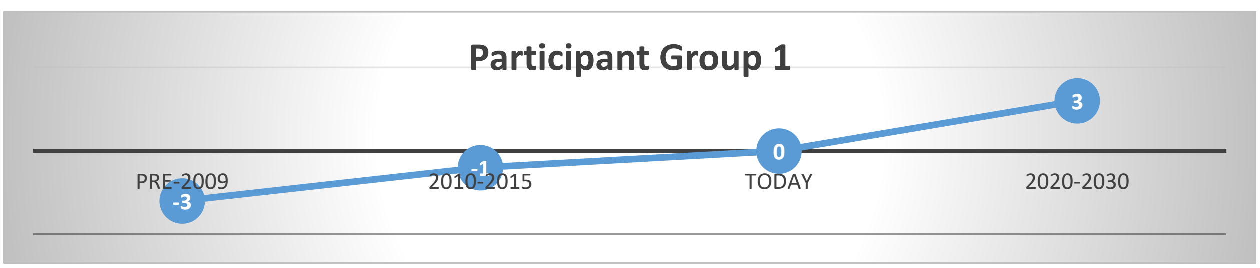
Broadly, and with a high degree of consensus, implementation of LDAR programs was lower in the past than today and will be higher in the future than currently.

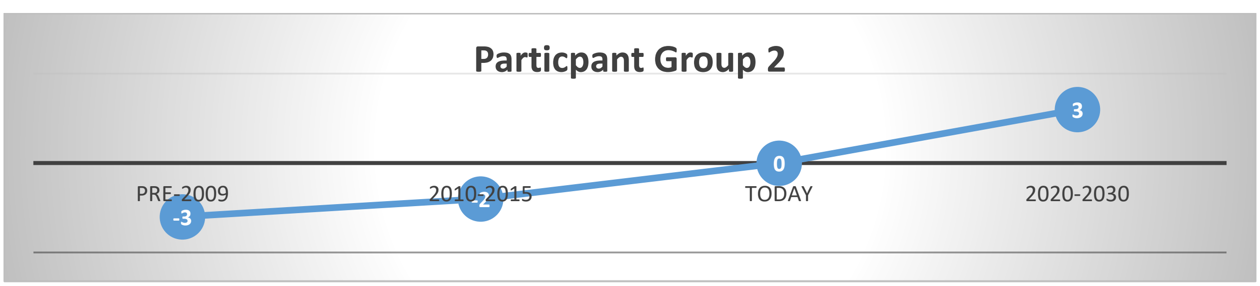
Distant Past: effectively no LDAR programs were in place. CAPP published the Best Management Practice for Fugitive Emissions in 2007 with implementation beginning in the following years, so LDAR guidance and definitions had not yet achieved wide awareness.

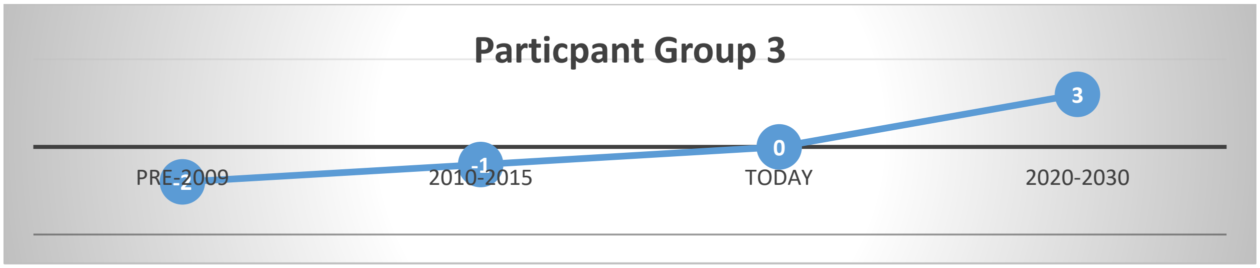
Recent Past: LDAR implementation varies with each Producer but was generally lower than currently. Risk-based LDAR was conducted for gas plants and larger facilities, but not individual well sites. The guidance in BMP was not prescriptive or required by regulation, and some Producers conducted no LDAR.

Future: implementation of the regulations will result in an increase in LDAR programs. Mandatory LDAR will drive the development of cost-effective emissions detection programs. Following implementation of regulations for 2 – 5 years, a decrease in frequency may be observed as regulations accommodate and approve alternative LDAR programs. Despite a reduction in frequency, emission reductions will remain stable.

Workshop consensus on directionality and magnitude of change in the future: ↑↑↑ *(3)*







4.2.3 Prevalence of High Bleed Pneumatics

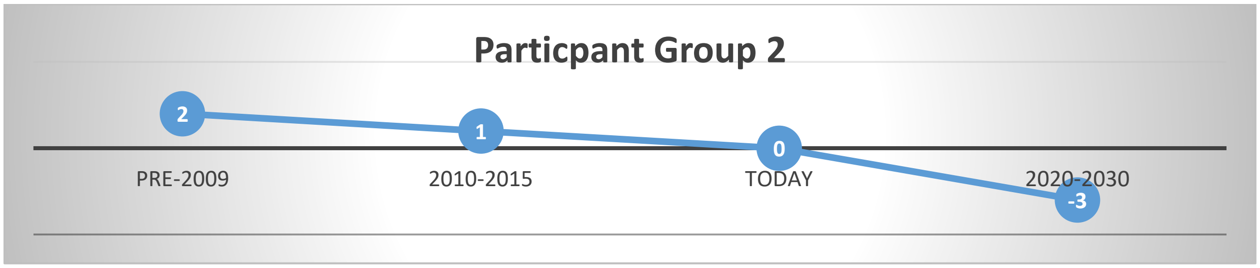
The prevalence of high bleed pneumatics was much higher in the distant past relative to current operations, and Participants were aligned on this model driver.

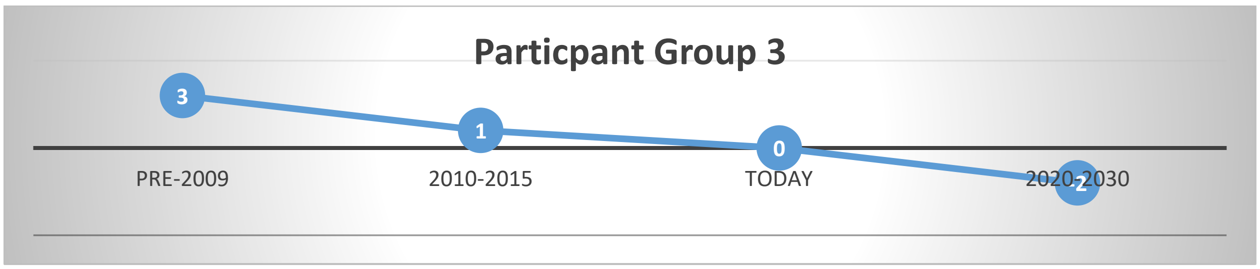
Distant Past: far more high bleed pneumatics were in operation than current practices, as they were cost effective and no regulation in place to limit their use. In a number of applications, low-bleed pneumatics were not commercially available. However, some participants noted that in the past, more sour gas was being produced, and, due to safety concerns, sour production is often no-bleed; this consideration shifted one group's rating from a magnitude of 3 to 2.

Recent Past: use of high bleed pneumatics in recent years had decreased as new builds began to include low bleed pneumatics and energy efficient programs/pilots were implemented. Retro-fits were not yet common. One market-dominant supplier of control instruments began manufacturing high-quality low bleed pneumatics, which became increasingly cost effective, and towards the end of the time period some high-bleed models were phased out entirely.

Future: once the regulations have been implemented, only certain legacy high bleed pneumatics will be in operation. The absolute magnitude of the reduction of high bleed use depends on any given producer's inventory. For producers with low numbers of high bleed pneumatics, the absolute magnitude will be small but the relative magnitude will approach 100%. Participant Group 1 intentionally left this blank but discussed the context of their answer with the group.

Workshop consensus on directionality and magnitude of change in the future: ↓↓↓ *(-3)*





4.2.4 Prevalence of Methane Mitigation Technologies

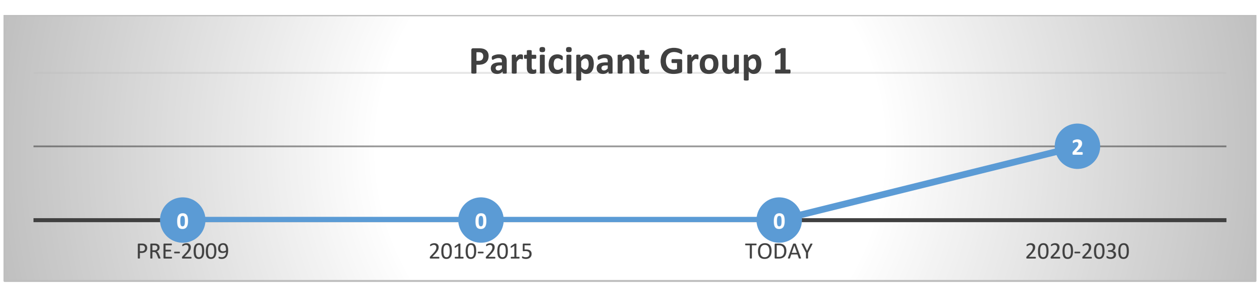
Broadly, there was good consensus that focus on methane mitigation has generally increased over time.

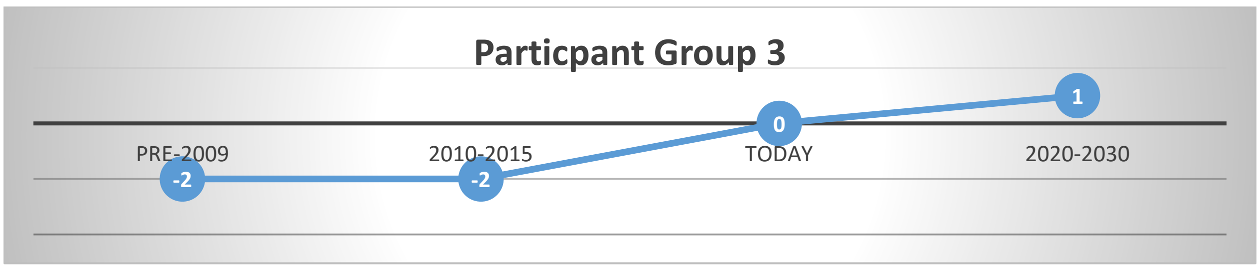
Distant Past: Generally, less mitigation was conducted than currently, and flaring was more prevalent. Less vapour recovery occurred than in current operations, and commercially available technologies were more limited.

Recent Past: increasingly, instrument air devices were being used and vapour recovery units were installed. Flaring and venting were both more prevalent relative to current operations. Technologies like VRUs and incinerators were not cost effective.

Future: Implementation of the regulations will result in an increase in mitigation and may also drive the development of more efficient or cost-effective technologies. Participants expect an increased use of vapour recovery units (VRUs), vent gas capture (for conservation or destruction) and enclosed combustors. However, given that many technologies are currently already in use on some facilities, the magnitude of change will not be 3.

Workshop consensus on directionality and magnitude of change in the future: ↑↑ *(2)*





4.2.5 Level of Preventative Maintenance

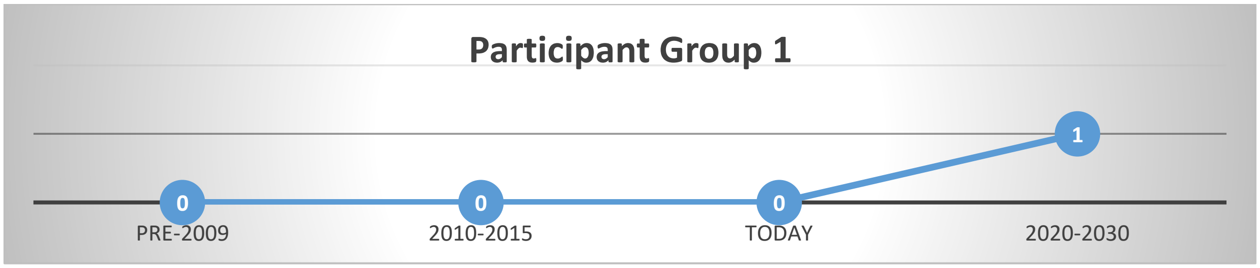
Participants identified that the level of preventative maintenance any given Producer achieves will not likely change over time as it is typically driven by things like safety as opposed to emissions. Preventative maintenance will vary from Producer to Producer, but any given Producers maintenance program will generally remain constant over time. Regular turnarounds have always occurred and will continue, for a variety of reasons unrelated to methane emission reductions.

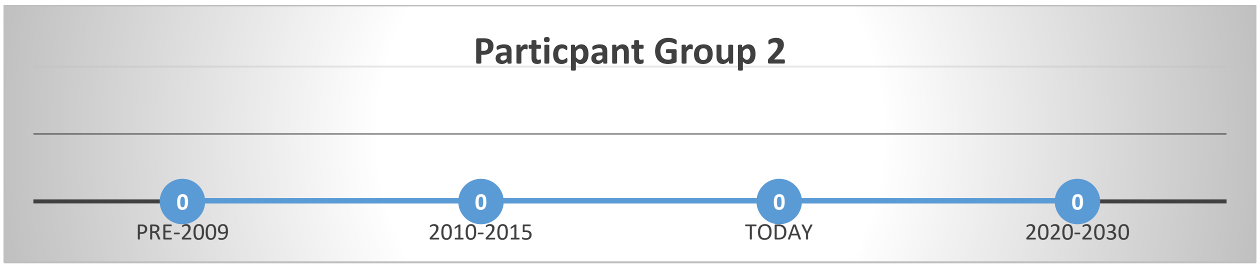
Distant Past: no change.

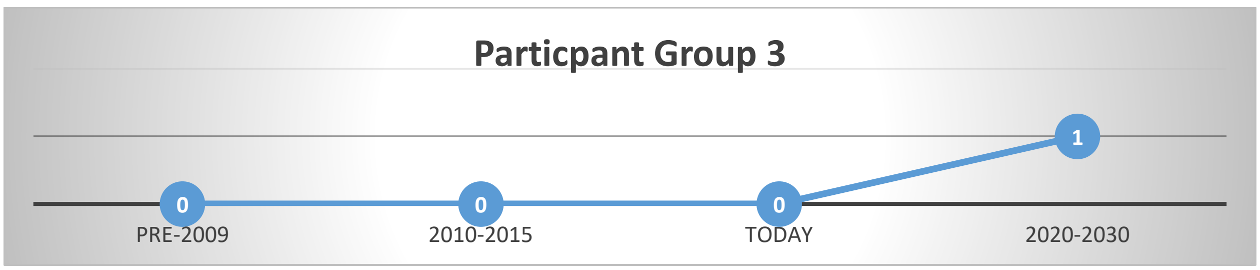
Recent Past: no change.

Future: Only within the context of the future did Participants anticipate a change in preventative maintenance programs. As new technologies are brought in to service a growing industry, preventative maintenance programs may increase in magnitude. Additionally, mandatory LDAR may be an incentive for Producers to implement regular maintenance in advance of detection surveys. The use of big data management and analytics was seen as a potential shift that would create more efficient preventative maintenance.

Workshop consensus on directionality and magnitude of change in the future: ↑ *(1)*







4.2.6 Prevalence of Non-Emitting Pneumatic Devices

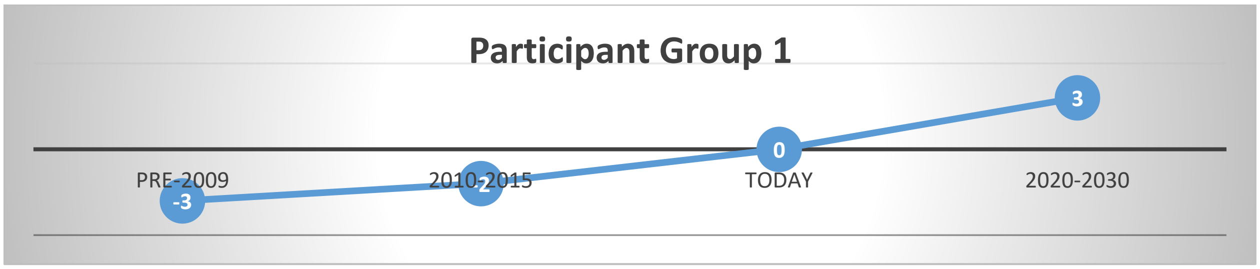
There was broad consensus in the workshop that the prevalence of non-emitting pneumatic devices increases through time, although magnitude of change can depend on many factors, including operations of individual Producers.

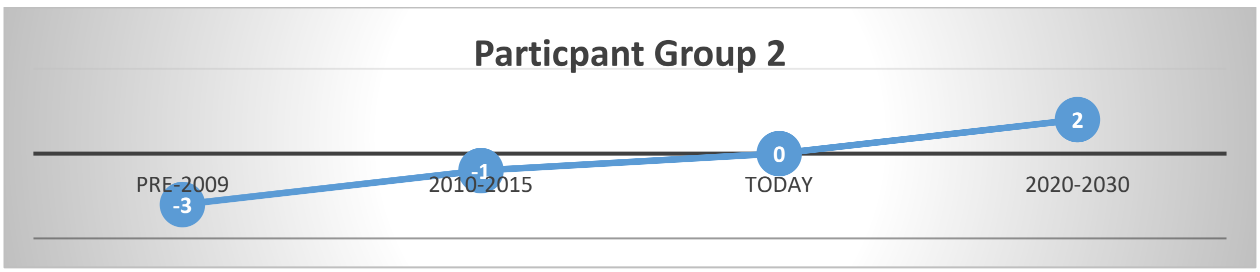
Distant Past: Significantly fewer non-emitting pneumatic devices were in operation pre-2009. Some Participant Groups indicated that, generally, non-emitting pneumatics were not in operation at all.

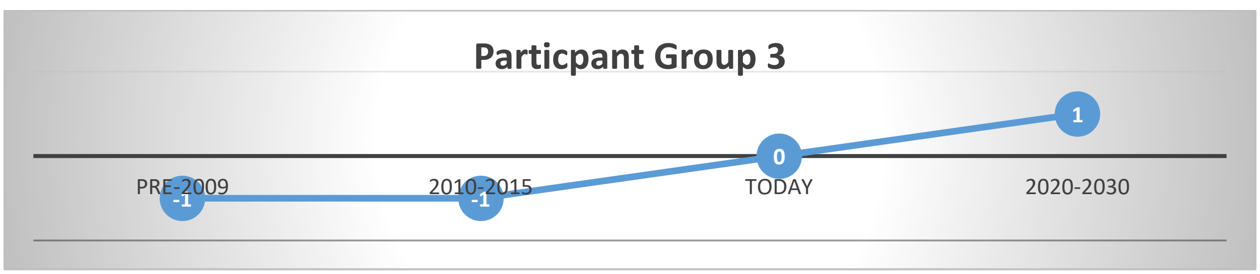
Recent Past: Over this period, well electrification projects became more prevalent, as did solar-powered devices and other remote power options such as thermoelectric generators.

Future: Most new builds will have non-emitting pneumatics. Having access to cost-competitive electricity from the grid is a significant consideration in increasing non-emitting pneumatics. Assuming that by 2022, pneumatics will be switched out, this driver will only experience a small magnitude increase as new technologies come online. Most new facilities will be non-emitting in their control and chemical injection systems, equivalent to a magnitude of 3 decrease; however, legacy facilities with some emitting pneumatic devices will continue to exist resulting in a magnitude of 2 decrease.

Workshop consensus on directionality and magnitude of change in the future: ↑↑ *(2)*







4.3 Potential for Incentivization

In closing the afternoon, participants were individually asked to provide general opinions on potential types of future market conditions or incentives that may drive implementation or a reduction technology or method sooner than the implementation of regulations, or to a magnitude that goes beyond what is required for compliance.

Electricity

- Collaboration between Producers and various levels of government to get Producers access to cost-competitive electricity; and
- Access to cost-competitive electricity from the grid is a key component of success and growth in the BC fields.

Incentives

- Offer carbon offsets as an incentive;
- Use programming structures already utilized by other programs, such as the Clean Infrastructure Royalty Credit Program;
- Expand the flexibility of current and future incentives to allow for the combination of different incentives programs to drive increase in participation;
- Offer incentives for condensing wells to superpads (lower footprint);
- Offer incentives for research and development that will drive lower production costs; and
- Offer incentives for early adopters of technology or programs.

4.4 Chapter 4 Summary

Three temporal states – distant past, recent past, and future – were interrogated across six specific focus areas in terms of the direction and relative magnitude of change from the “present” observed in the field study. The workshop leveraged industry experience to guide subjective changes to modeling parameters over different time periods, including forecasting and backcasting of methane emissions in British Columbia.

Broad agreement, especially with historical time periods, was achieved within the workshop in terms of defining a narrative of oil and gas production in the province and defining a potential future scenario. Assessment of methane emission modeling drivers was evaluated from a variety of perspectives, and insights into key drivers that might influence parameters of interest for time-series modelling was determined.

Closing

The British Columbia Methane Emissions Field Study incorporated a broad scope of field data, corporate data, and temporal trends in order to inform time-series modeling of methane emissions in British Columbia. The development of BC-specific methane emissions parameters can also improve understanding of the characteristics that make the province unique, those which are consistent with other jurisdictions, and can elicit the next round of questions to be answered for further improvement.

Appendix A: Data Tables

See supplemental attachment.

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CLEAN AIR ADVOCATES' EXHIBIT 8

COLORADO

Air Pollution Control Division

Department of Public Health & Environment

Dedicated to protecting and improving the health and environment of the people of Colorado

Pneumatic Controller Task Force Report to the Air Quality Control Commission

Pneumatic Controller Field Study and Recommendations

June 1, 2020

CAA Ex. 8

TABLE OF CONTENTS

1 Introduction

This report was developed in response to a December 2017 rulemaking, in which the Colorado Air Quality Control Commission (AQCC) established a pneumatic controller (PC) 'Find and Fix' program for oil and gas well production facilities and natural gas compressor stations located in the ozone non-attainment area (NAA). The AQCC recognized that continuous bleed and intermittent pneumatic controllers are designed to have emissions but these emissions can be excessive when the controllers are not operating properly. The AQCC adopted the Find and Fix program to reduce excess emissions from such natural gas-driven pneumatic controllers.

As part of the Statement of Basis and Purpose (SBAP), and at the request of industry and other stakeholders, the AQCC adopted a "reassessment" provision for the Find and Fix program. The reassessment was to follow an Air Pollution Control Division (Division) led study of pneumatic controller emission reduction options, including the rate, type, application, and causes of pneumatic controllers found operating improperly; inspection and repair techniques and costs; available preventative maintenance methods; appropriateness of the definitions of enhanced response, intermittent pneumatic controller, no-bleed pneumatic controller, self-contained pneumatic controller, and pneumatic controller; and other related information. The AQCC also directed that more information on "good engineering and maintenance practices" should be gathered during the pneumatic controller study and implementation of the Find and Fix program to inform the reassessment. As part of the reassessment, industry agreed to participate in a study focused on the Denver-Julesburg (DJ) Basin that would collect data on the types of PCs in service, those PCs determined to be operating improperly, what caused the PCs to not operate properly, and the repairs taken to return the PCs to proper operation across a representative cross section of well production facilities and natural gas compressor stations in the NAA.

The AQCC directed the creation of a Pneumatic Controller Task Force (PCTF) comprised of representatives of the Division, operators and industry trade groups, local governments, and conservation groups. The PCTF was to brief the AQCC annually and make recommendations in this report, and each participant was to have the opportunity to contribute to the briefings and report. The AQCC also recognized that the pneumatic controller study and inspection program might inform the strategies for cost-effective hydrocarbon emission reductions for pneumatic controllers, including zero emission pneumatic controllers, under consideration by the Statewide Hydrocarbon Emission Reduction (SHER) team. The AQCC also established the SHER team through the SBAP for the December 2017 rulemaking.

The PCTF convened for the first time on January 25, 2018. The group held bi-weekly meetings for several months to develop and design the study. Field inspections of production facilities selected for the study started on May 1, 2018. Afterwards, meetings were held bi-monthly to check on the progress of field inspections and updates on data management until the data was submitted to the Division in December 2018. The group met in January 2019 to discuss initial data analysis, finalize the project plan, and revisit goals. The PCTF briefed the AQCC on February 21, 2019 on its progress. Throughout the spring of 2019, industry PCTF members developed and responded to questionnaires to document and assess the effectiveness and costs of inspection techniques as well as to understand opportunities for expanded use of no-bleed PCs. The PCTF and the SHER team held a joint meeting on June 11, 2019, to hear presentations on Canadian regulation of pneumatic controllers.

In April 2019, the legislature adopted Senate Bill 19-181, which directs the AQCC to "review its rules for oil and natural gas well production facilities and compressor stations and specifically consider adopting more stringent provisions, including . . . a requirement to reduce emissions from pneumatic devices. The AQCC shall consider requiring oil and gas operators, under appropriate circumstances, to use pneumatic devices that do not vent natural gas." The PCTF was effectively put on hold in the summer of 2019 to allow its members to focus on regulatory proposals to be addressed during the December 2019 SB 19-181 Rulemaking. In that rulemaking, the AQCC adopted the SHER team's proposal to (1) expand the Find and Fix program statewide, (2) include language in the SBAP directing continued work to evaluate the use of zero-bleed pneumatic devices, and (3) provide for a compliance assistance approach for operators outside the nonattainment area while those operators get up to speed on the Find and Fix program. In the SBAP, the AQCC directed the SHER team and PCTF to continue their work on the mandates established in 2017, and to bring back to the AQCC in 2020 their recommendations on the use of zero-bleed pneumatic devices.

Members of the PCTF were requested in April 2020 to review and complete this report.

1.1 2017 AQCC Reg 7 Oil and Gas CTG Rulemaking and Pneumatic Inspection Program

Below is a summary from the Statement of Basis and Purpose prepared for the 2017 AQCC Regulation 7 rulemaking that explains the actions taken by the AQCC for the 2017 rulemaking and the direction given to the Division to convene a PCTF.

1.1.1 Background

On May 4, 2016, the U.S. Environmental Protection Agency ("EPA") published a final rule that determined that Colorado's Marginal ozone NAA failed to attain the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"). EPA, therefore, reclassified the Denver Metro North Front Range ("DMNFR") area to Moderate and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone data.

As a result of the reclassification, on May 31, 2017, Colorado submitted to EPA revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") Moderate NAA requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)). As a Moderate NAA, Colorado revised its SIP to include Reasonably Available Control Technology ("RACT") requirements for each category of volatile organic compound ("VOC") sources covered by a Control Technique Guidelines ("CTG") for which Colorado has sources in the DMNFR that EPA finalized prior to a NAA's attainment date. EPA finalized the CTG for the Oil and Natural Gas Industry ("Oil and Gas CTG") on October 27, 2016, with a state SIP submittal deadline of October 27, 2018. Given this timing, the November 2016, SIP revisions did not include RACT for the oil and natural gas source category and Colorado needed to further revise its SIP.

The Oil and Gas CTG recommends controls that are presumptively approvable as RACT and provide guidance to states in developing RACT for their specific sources. In many cases, Colorado had similar, or more stringent, regulations comparable to the recommendations in the Oil and Gas CTG, though many of these provisions were not currently in Colorado's Ozone SIP. Therefore, on November 16, 2017, the AQCC adopted RACT for the oil and gas sources covered by the Oil and Gas CTG (CTG as of October 27, 2016) into the Ozone SIP. In order to make additional progress towards attainment of the NAAQS, the AQCC also adopted State Only revisions to require owners or operators of oil and gas well production facilities and compressor stations with natural gas-driven PCs in the DMNFR area to inspect and maintain these PCs.

1.1.2 PC Find and Fix program

The AQCC adopted an inspection and enhanced response (*e.g.*, maintenance) program for natural gas-driven PCs. While the Oil and Gas CTG notes the value of PC inspection and maintenance, the Oil and Gas CTG does not specify PC inspection and maintenance as presumptive RACT. The AQCC therefore created a new program that requires that natural gas-driven PCs at well production facilities and natural gas compressor stations in the DMNFR be inspected periodically to determine whether the PC is operating properly. The program requires that owners or operators inspect PCs for proper operation as part of routine LDAR regulatory programs at well production facilities annually, semi-annually, quarterly, or monthly, depending on the well production facility VOC emissions, and at natural gas compressor stations quarterly or monthly, depending on the natural gas compressor station fugitive emissions.

This PC inspection and enhanced response process was intended to be a multi-step process. First, the owner or operator must inspect all natural gas-driven PC using an approved instrument monitoring method (AIMM) to screen for detectable emissions. This first step allows owners or operators to narrow potential response efforts to only those PCs with detected emissions. Second, the owner or operator must determine whether the PCs with detected emissions are operating properly. Use of an AIMM is not required during this second step; the AQCC did not lay out a process for how owners or operators are to determine if their PCs are operating properly. During this second step, if an owner or operator determines that the PC is operating properly, no further action is necessary. Third, where an owner or operator determines the PC is not operating properly, the owner or operator must take actions to return an improperly operating PC to proper operation. Fourth, general recordkeeping and reporting requirements apply broadly to the number of facilities inspected and number of inspections. More detailed recordkeeping and reporting is required for those PCs that the owner or operator determined not to be operating properly. Similar to the LDAR records, owners or operators must keep records of the date the PC was returned to proper operation and a description of the types of actions taken.

1.1.3 Reassessment Provision

The reassessment provision is explained as follows in the SBAP for the 2017 Reg 7 CTG rulemaking.

The AQCC adopted a “reassessment” provision for this inspection and enhanced response program following a Division led study of PC emission reduction options, including the rate, type, application, and causes of PCs found operating improperly; inspection and repair techniques and costs; available preventative maintenance methods; appropriateness of the definitions of enhanced response, intermittent pneumatic controller, no-bleed pneumatic controller, self-contained pneumatic controller, and pneumatic controller; and other related information. The AQCC also recognized that owners and operators may have limited information on “good engineering and maintenance practices” for PCs and intended that more information on these practices are gathered during the pneumatic study and implementation to inform the reassessment of the inspection and enhanced response program. The data collection effort will include data from a representative cross-section of well production facilities and natural gas compressor stations in the DMNFR. In accordance with industry’s proposal, a task force was directed to convene by January 30, 2018, consisting of representatives from industry, the Division, local governments, environmental groups, and other interested parties. Data collection was scheduled to commence no later than by May 1, 2018. The task force *will* brief the AQCC annually and make any recommendations on its findings in a report (this document) to the AQCC due May 1, 2020. The AQCC *intends* that the Division, industry, local government, and environmental group task force participants each have the opportunity to contribute to the final report and provide one representative to speak during the briefings to the AQCC. The AQCC intended that this information be used to reassess the natural gas-driven PC requirements of Regulation Number 7 that will remain in effect until rescinded, superseded, or revised.

1.1.4 2019 Rulemaking Directives

Below is an excerpt from the Statement of Basis and Purpose prepared for the 2019 AQCC Regulation 7 rulemaking that explains the actions taken by the AQCC for the 2019 rulemaking and the direction given to the PCTF and SHER Team:

> "Pneumatic Controllers (Part D, Section III.)
>
> SB 19-181 also directed the Commission to consider a requirement to reduce emissions from pneumatic devices. In the 2017 emissions inventory for the Moderate area ozone nonattainment SIP, pneumatic devices were identified as the second largest oil and gas area source (after tanks). In 2017, the Commission convened the Statewide Hydrocarbon Emission Reduction (SHER) team, to consider measures – both regulatory and voluntary – to reduce hydrocarbon emissions from the oil and gas sector. The Commission, at the same time, also established the Pneumatic Controller Task Force (PCTF), with a mission to collect and review data about pneumatic controllers and identify ways to reduce emissions from that equipment. After almost two years of work, the SHER team developed an early recommendation concerning pneumatic controllers, which the Commission has now adopted.
>
> The SHER team supported a three-prong approach. First, the expansion of the pneumatic controller inspection and enhanced response program state-wide. Second, the SHER team recommended including language in this Statement of Basis and Purpose, directing the continued work to evaluate the use of zero-bleed pneumatic devices. Third, the SHER team supported a compliance assistance approach for operators outside the nonattainment area, while those operators get up to speed on the pneumatic controller inspection and enhanced response program that has been implemented in the nonattainment area since 2018.
>
> The Commission approves of this approach and commends both the SHER team and PCTF for their work since 2017, building the knowledge that informed provisions of this rulemaking. The Commission has therefore expanded the pneumatic controller inspection and enhanced response program state-wide. At the same time, the Commission recognizes that there is much to learn about the inspection and maintenance of natural gas-driven pneumatic controllers outside the nonattainment area, which highlights the need for enforcement discretion. The Commission intends that for operations outside the nonattainment area, the determination of whether a pneumatic controller is operating properly will be made by the owner or operator, with minimal oversight by the Division for the first year of implementation.

> The Commission further directs the SHER team and PCTF to continue their work on the mandates established in 2017, and to bring back to the Commission in 2020 their recommendations on the use of zero-bleed pneumatic devices. Specifically, the Commission continues to direct the PCTF to make recommendations on its findings in a report to the Commission in May 2020. However, the Commission revises its directive to the SHER team to present recommendations by no later than January 2020, to by no later than July 2020. This revised timeline will provide additional time for the SHER team to make any additional recommendations on cost-effective hydrocarbon emission reduction strategies evaluated by the SHER team. The Commission anticipates that the SHER team will also evaluate continuous methane emission monitoring and engage in discussions to determine actual leak rate percentages of components at oil and gas facilities for use in future rulemakings."

2 Pneumatic Controllers

This section provides some basic information regarding PCs, with a focus on the PCs studied recently in Colorado.

2.1 What is a PC, what does it do?

PCs are found widely on oil and natural gas production facilities in Colorado. PCs are used to automate and regulate process control variables such as temperature, pressure, liquid level, and to maintain critical safety fail-safe functions. PCs operate by sensing a condition and then sending a signal to a valve actuator that in turn controls a valve that controls the process parameter in question. For instance, a liquid level controller will sense liquid levels in a separator and send a signal (in the form of natural gas pressure) to a valve actuator on a dump valve which in turn opens the dump valve and lowers the liquid level in the separator. It is important to note that the PC, the valve actuator, and the valve are all different components of the control system. It is not uncommon for the PC to be located several feet away from the valve actuator and the valve it is controlling. Finally, it is important to realize that the valve being controlled by the PC is a component that is already subject to the LDAR provisions of Regulation Number 7. Similarly, there are many connectors associated with PCs and valve actuators - each of which is also a component subject to the LDAR provisions. As such, it is important to distinguish emissions from leaking components that are routinely found and repaired in an LDAR program, from emissions caused by an improperly operating PC.

2.2 Types of PCs

As part of their normal function, PCs emit natural gas when they actuate, either intermittently or continuously. Continuous and intermittent PCs are the two broad categorizations of PCs that were the focus of the 2018 PCTF field study. The categorization refers to how the PC is expected to emit under normal operation. A continuous PC is designed to emit at a steady rate, commonly referred to as a bleed rate. The bleed rate may change during actuation. Contrastingly, an intermittent PC is only expected to emit above a de minimis level during actuations and hence they do not have a bleed rate per se. Some intermittent PCs actuate very frequently and some only rarely. For instance, a liquid-level controller on a new high producing well may actuate many times within an hour. There may be significant emissions associated with this normal, intended operation.[1]

There are also non-emitting controllers, often referred to as “no-bleed,” “zero-bleed” or “zero-emitting”[2] PCs. These devices do not emit natural gas to the atmosphere during any phase of normal operation. Many of these devices are inherently non-emitting because they are driven by electricity or pressurized air, rather than pressurized natural gas. Since the intent of this field study was to examine emissions associated with natural gas-driven PCs, non-emitting PCs were not included in the scope of the 2018 PCTF field study.

Contained within the continuous PC category are high-bleed and low-bleed PCs. High-bleed PCs are designed to emit over 6 standard cubic feet per hour (scf/hr) of gas between actuations. Low-bleed devices emit less than 6 scf/hr. As of 2020, the Division believes that there are no high-bleed devices in use within the State of Colorado and all continuous-bleed PCs reported during this study were low-bleed.

2.3 Improper operation

Numerous studies have identified that a small number of improperly operating PCs are typically responsible for the majority of emissions from the PC population[3,4,5]. This information is what originally prompted the AQCC to adopt a PC find and fix program. The PCTF took a similar approach with the field study by focusing on “proper” vs “improper” operation.

2.3.1 Causes

Improper operation could be caused by any number of issues affecting a PC. These causes range from small amounts of debris keeping the controller from reseating properly to broken internal parts or defects in the housing for the PC. The causes specifically identified in the field study included: abnormal operation parameters, corrosion, debris, diaphragm failure, seal failure, spring failure, and wet supply gas.

2.3.2 Effects and Indicators

Operator personnel utilize AIMM (typically an OGI camera) to detect emissions from production facilities during LDAR inspections. Identification of a PC that is not operating properly requires additional knowledge regarding the types of PCs and their emission characteristics during normal operation in order to distinguish improper operation with an OGI camera.

Common tell-tale signs of PC improper operation include: loss of or improper control of the process parameter the PC is supposed to control; continuous emissions from an intermittent PC; excess emissions, as compared to normal operation, as identified via audio, visual, and olfactory (AVO) inspections or AIMM, from a controller; or obvious signs of significant staining

[1] Stovern, 2020: Understanding oil and gas pneumatic controllers in the Denver-Julesburg basin using optical gas imaging, Journal of the Air & Waste Management Association.
[2] Simpson, 2014. Pneumatic controllers in upstream oil and gas. Oil Gas Facil. 3(5):83–96.
[3] Allen, 2014. CH4 emissions from process equipment at natural gas production sites in the United States: Pneumatic controllers. Environ. Sci. Technol. 49 (1):633–40.
[4] Luck, 2019. Multi-day measurements of pneumatic controller emissions reveal frequency of abnormal emissions behavior at natural gas gathering stations. Environ. Sci. Technol. Letters 6:348–52.
[5] Thoma, 2017. Assessment of Uinta basin oil and natural gas well pad pneumatic controller emissions. J. Environ. Prot. 8:394.

or corrosion. A subset of improperly operating PCs may also be able to be identified by field personnel using their AVO senses; however, all inspections in this study used AIMM and did not solely rely on AVO observations.

3 PC Task Force

3.1 PCTF Goals

The PCTF members established the following goals for the PC study:

- Identify and collect natural gas-actuated PC data from a representative subset of well production facilities and compressor stations in the NAA
    - Set parameters of "improper operation" for each type of PC
    - Develop, document, and assess the effectiveness and costs of inspection techniques
    - Document malfunction rates and causes for types, makes, and models of PCs in different types of service
    - Document the effectiveness and costs of repair techniques and preventative maintenance
    - Estimate the number of PCs typically associated with a separator or other grouping of equipment

- Gather information regarding "good engineering and maintenance" practices

- Evaluate the appropriateness of the definitions in Regulation No. 7 for enhanced response, intermittent pneumatic controller, no-bleed pneumatic controller, self-contained pneumatic controller, and pneumatic controller

- Gather information about the current applications, cost, effectiveness, current applications and opportunities for expanded use for no-bleed and self-contained PCs

- Produce timely annual presentations and a report to the AQCC

3.2 Implementation Plan

The PCTF formed three distinct groups to address different elements of designing the field study: a main core group and two subgroups. One subgroup selected representative facilities and the second subgroup developed a field data form. Members of the PCTF provided several technical presentations to grow the shared knowledge base during the study development phase.

Once the field inspection campaign commenced on May 1, 2018, bimonthly meetings were held to check on the progress of field inspection and subsequent data management until the compiled and blinded data was submitted to the Division in December 2018. The two subgroups disbanded once 2018 sampling began while the main core group continued to meet.

4 PC Field Study

4.1 Participating Stakeholders

The field study was designed with the help of all PCTF stakeholders. These stakeholders include: the Division, the American Petroleum Institute (API), the Colorado Oil and Gas

Association (COGA), nine upstream oil and gas well production operators, one midstream operator, the Clean Air Task Force (CATF), Earthjustice (EJ), the Environmental Defense Fund (EDF), Boulder County Public Health (BCPH), Denver Public Health and Environment (DDPHE), Colorado Communities for Climate Action (CC4CA), and the Regional Air Quality Council (RAQC).

The field study was implemented and conducted with the participation of nine upstream oil and gas well production facility operators in the DJ Basin. The study also surveyed PCs at the only two known natural gas compressor stations within the DJ Basin that operate natural gas-actuated PCs.

4.2 Study Design

4.2.1 PC Inspection Method Utilized

All PC inspections conducted at the facilities selected for this field study utilized an OGI camera to monitor and identify improperly operating PCs. Some operators also noted whether an improperly operating PC could have been identified using only AVO methods (e.g. visible staining or corrosion or audible hissing when not actuating).

4.2.2 Field Data Form Development

A subgroup was formed to develop the field data forms (Attachment A) that would be used by operators during PC inspections of the selected facilities to collect consistent metadata across operators and facilities. These forms were based on forms utilized by the Stovern et al (2020) study and amended to reflect the different data collection goals of the PCTF inspection process. The final data forms include general, inventory, inspection, and repair information. The data form options include PC type (including manufacturer and model), function, application, depressurization method, and type of service. The forms determine "improper operation" causes, including description(s). The forms note primary causes of improper operation such as debris, corrosion, equipment failures, broken or missing parts, or abnormal operational parameters; there is also an option for other causes.

Industry representatives provided extensive instructions (Attachment B) for field staff that detailed each item on the form step-by-step. The final data forms were available in paper and electronic form. Operators that utilized paper forms tabulated the data into the electronic form once the paper forms were returned to office staff. All data was submitted to the Division in electronic form.

4.2.3 Facility Selection

The PCTF extensively examined appropriate cross-sectional data for well production facilities and natural gas compressor stations. For well production facilities, the Division initially estimated about 7,000 well production facilities in the NAA counties. The group discussed how to appropriately divide the facilities into cohorts in order to identify which facilities should be sampled for the study. The factors discussed included type of drilling (horizontal vs. vertical), operation size based on production levels, facility age, and separator types. Ultimately, the subgroup decided that production level (barrels/day) was most appropriate and representative of the other variables being considered.

Industry then provided "snapshot" daily average production data from December 2017 for each of the nine participating operators to the Division on February 21, 2018, with subsequent updates based on stakeholder meeting discussions. This snapshot dataset for the nine participating operators represented approximately 80% of all well production facilities located in the NAA. The original dataset was grouped by level of production (barrels/day), and a 50 percent “Plug and Abandon” (P&A) rate for wells in the 0 - 10 bbls production level cohort was assumed, as these wells were largely older vertical wells likely to be shut-in or scheduled for P&A. This P&A rate assumption is based on multiple factors including, but not limited to, line pressure, economic considerations, lease agreement issues, and land use matters.

Industry updated the dataset on March 21, 2018, with more accurate information from the two largest participating operators, which decreased the P&A rate and provided a conservatively low estimate of the number of PCs to be surveyed at each well production facility, based on its level of production. This analysis was conducted to demonstrate that the study would sample a sufficient number of selected facilities in each production cohort, to provide an adequate data set for the study.

After further meetings and discussion, the PCTF decided on the following cross-sectional sample of well production facilities to be subject to PC inspections starting May 1, 2018, shown in Table 1:

Table 1: Preliminary DMNFR Ozone NAA Well Production Facility Dataset (2018 Sampling Estimate)

Production Buckets	Estimated number of controllers per facility	Total No. of Facilities	Proposed Sample %	Proposed No. of Sample Facilities	Estimated # of controllers
>250 bbls/day	50	104	13	14	700
10-250 bbls/day	20	553	7	39	780
0-10 bbls/day	5	2,509	5	125	625
TOTAL		**3,166**		**178**	**2,105**

The actual sampling that took place resulted in one extra facility inadvertently being surveyed by one of the operators. Additionally, because operator PC count estimates were intentionally conservative, a significantly higher number of controllers were actually surveyed during the study. The actual final 2018 well sampling facility and PC numbers inspected are shown below in Table 2.

Table 2: Final DMNFR Ozone NAA Well Production Facility Dataset (May - October 2018)

Production Buckets	Average number of controllers per facility	Total No. of Facilities	Proposed Sample %	Proposed No. of Sample Facilities	Final # of controllers
>250 bbls/day	98	104	13	14	1,378
10-250 bbls/day	34	553	7	39	1,319
0-10 bbls/day	9	2,509	5	126	1,141
TOTAL		**3,166**		**179**	**3,838**

For natural gas compressor stations, the Division initially requested industry feedback on potential data for inclusion in the May 2018 sampling. After further stakeholder discussion, the Division conducted an independent analysis using its databases to determine the number of active natural gas compressor stations in the NAA and gathered industry feedback by facility. The final analysis showed 58 active natural gas compressor stations operated by eight companies. The Division received feedback on 86% of the stations (50 stations) by June 2018 (four out of eight operators). Of these, 48 stations are currently operating or under construction to operate on instrument air, or have been depressurized and are not included in the field inspections. Two natural gas compressor stations were confirmed to use natural gas-driven PCs and were included in the study. These two natural gas compressor stations were sampled in the summer of 2018. Nine compressor stations are operated by non-participating operators and are of an unknown status at the time of the study. It is likely that at least some of these natural gas compressor stations are operated on instrument air since 4% (two out of 50) of the participating stations use natural gas-driven PCs; however, this is assumed and not verified.

4.3 Field Campaign Summary

The PCTF field study began in May 2018 and data collection was finished by October 2018. On August 1, 2018, and September 11, 2018, Patrick Murphy (formerly of Boulder County) and Jeramy Murray (APCD) attended field surveys at four Noble Energy and two PDC Energy facilities to observe how industry field staff were implementing the study design.

4.3.1 Field Data Compilation

Spirit Environmental (Spirit) was retained by COGA to assist with implementation of the PCTF study plan, including facility selection, field data form development, and data validation and compilation. Once the representative cross-section criteria was developed, Spirit generated a randomly selected list of facilities to be inspected by participating operators. If a facility was not available for inspection, Spirit randomly chose a replacement facility that met the original criteria for that operator. Reasons for assigning a designating a site as unavailable included: depressurized, shut-in, P&A, divested sites, sites operating with instrument air, sites with landowner access restrictions, or incorrectly categorized sites.

4.3.2 Completeness and Consistency Review

All data collected by operators was compiled and blinded by Spirit Environmental before electronic submission to the Division. The data also went through a completeness and consistency check performed by Spirit, where operators were consulted to complete missing data fields and to better account for information provided, thereby improving field data reporting consistency between operators. For transparency, industry provided the compiled field data in both uncorrected and corrected spreadsheets that were made available to all stakeholders in the PCTF.

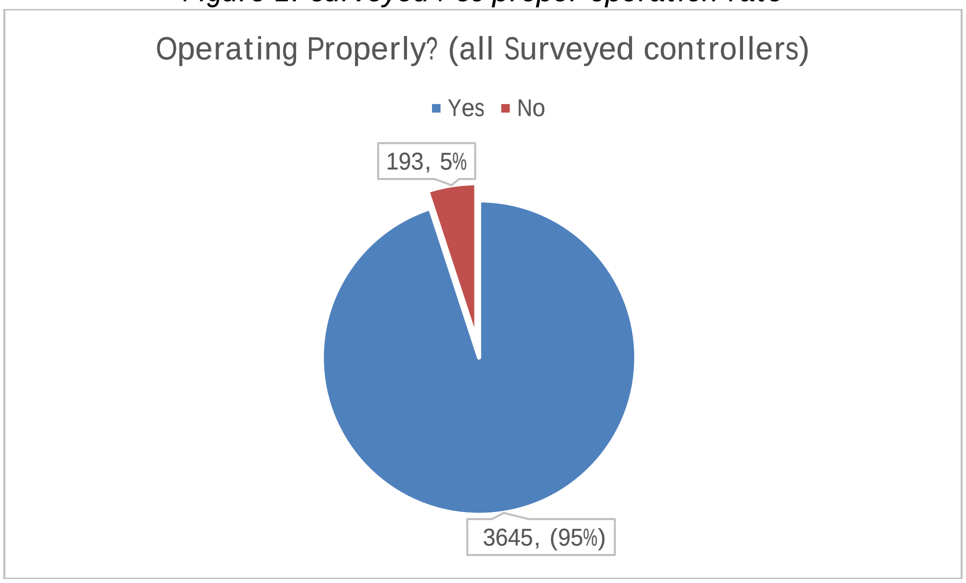
4.4 PCTF Study Data

The following sections contain summaries of key data collected during the PCTF field study. A full spreadsheet with all data collected in the program is available to stakeholders for analysis through the Division.

4.4.1 Oil and Gas Production Facility Data

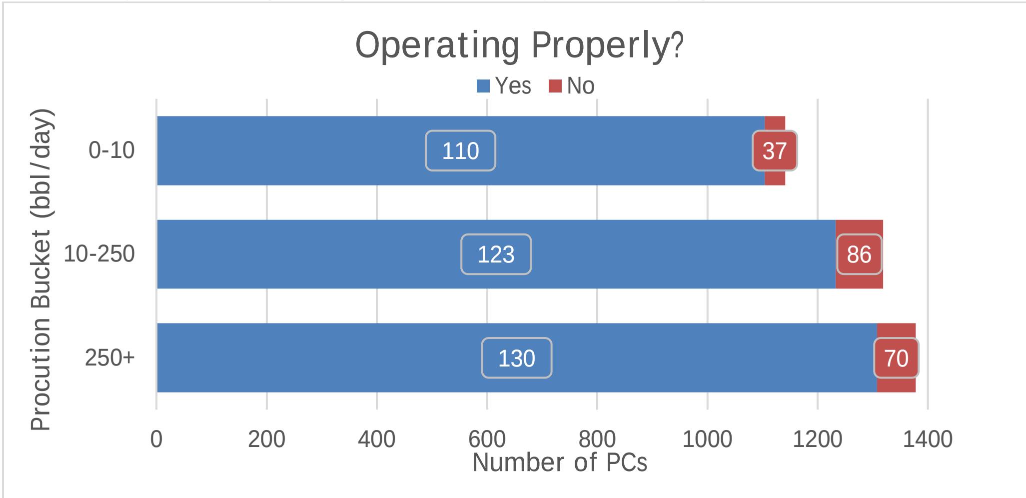
The study resulted in data points based on inspections for over 3800 PCs in the DJ Basin. Of the PCs observed, approximately 5% were observed to be improperly operating.

Figure 1. Surveyed PCs proper operation rate



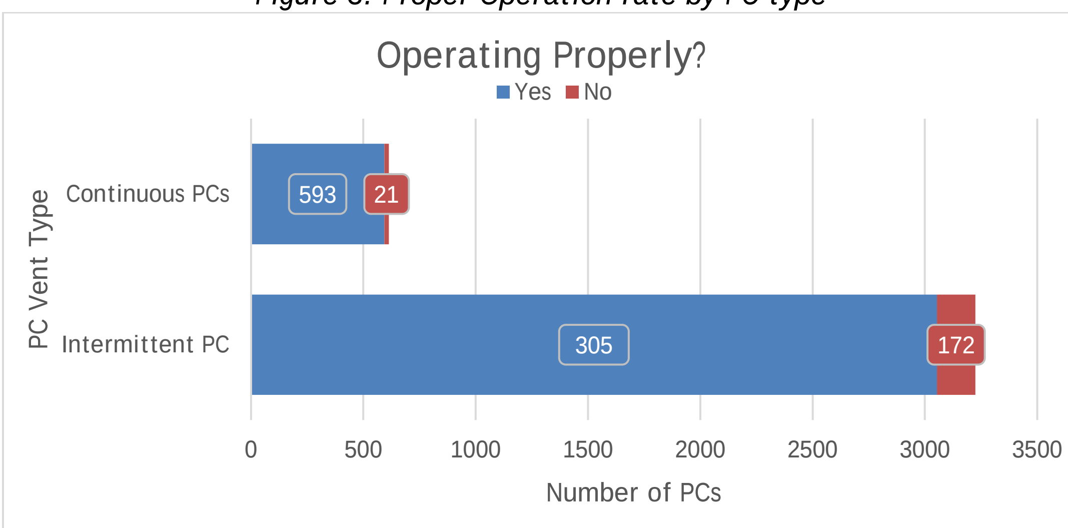
This data was also broken down by the three predetermined inventory production buckets. In the 0-10 bbl/day production bucket, 3.2% of all PCs were improperly operating. In the 10-250 and 250+ bbl/day buckets, 6.5 and 5.1% of PCS respectively were found to be improperly operating.

Figure 2. Proper Operation rate by inventory production bucket



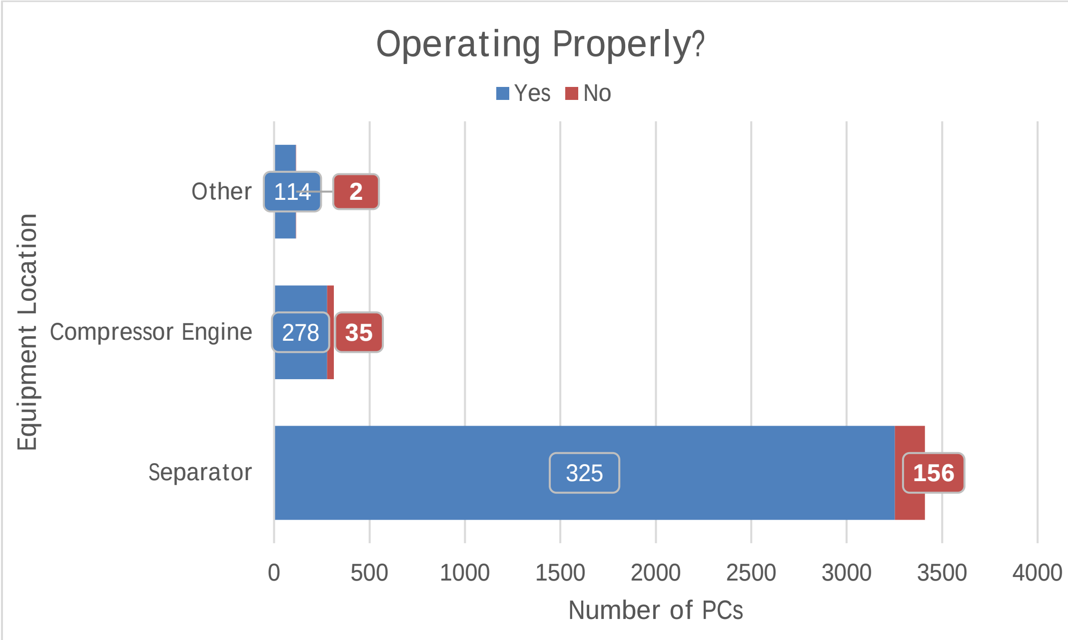
Breaking down the data by PC type (continuous vs. Intermittent) is also a useful way to look at the data. Continuous PCs were found to have an improper operation rate of 3.5% and intermittent controllers had a rate of 5.6%.

Figure 3. Proper Operation rate by PC type



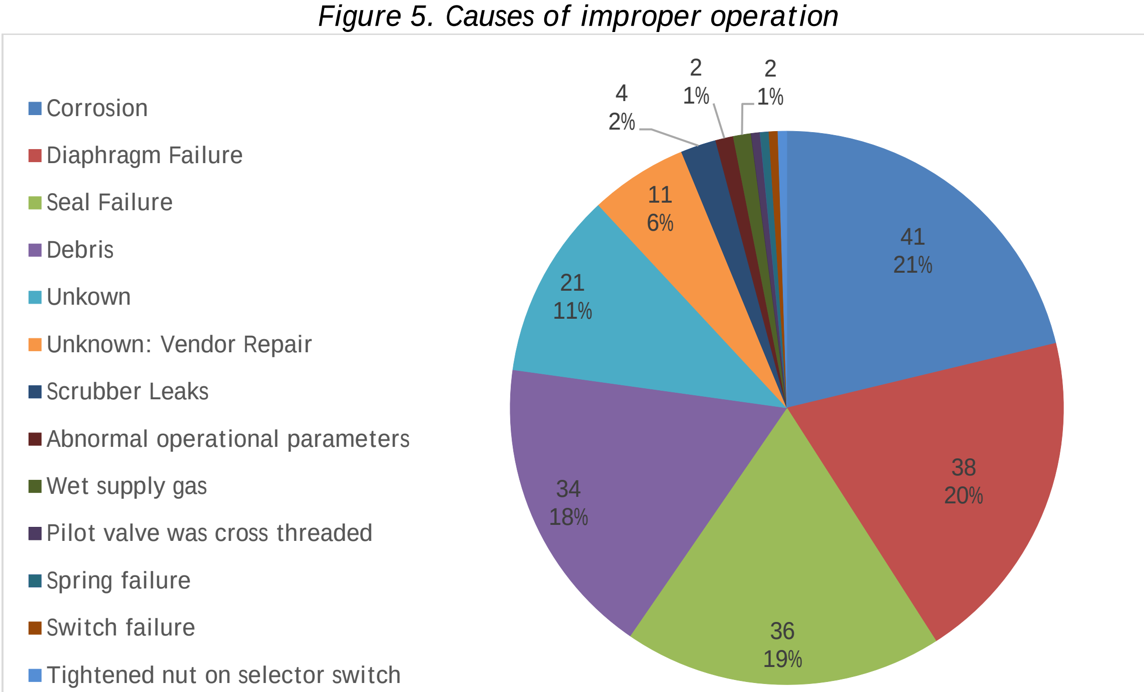
Operators tracked the facility equipment associated with each PC in the study. The majority of PCs are in-service on separation vessels. About 5% of PCs on separators were found to be improperly operating. The second most common PC equipment location was on the compressor engines. PCs on compressor engines had a relatively high improper rate of 12.3%. PCs found on all other equipment had a 2% improper operation rate.

Figure 4. Proper Operation rate by equipment location



The study revealed that there were a myriad of reasons that a PC might operate in an improper manner. The four largest causes were attributed to corrosion, diaphragm failure, seal failure, and debris blocking the internal mechanism from reseating.

Figure 5. Causes of improper operation



Operators made attempts to return all PCs to proper operation at the time of inspection if possible. Fifty (26%) of the 193 improperly operating PCs were repaired immediately. Ninety-

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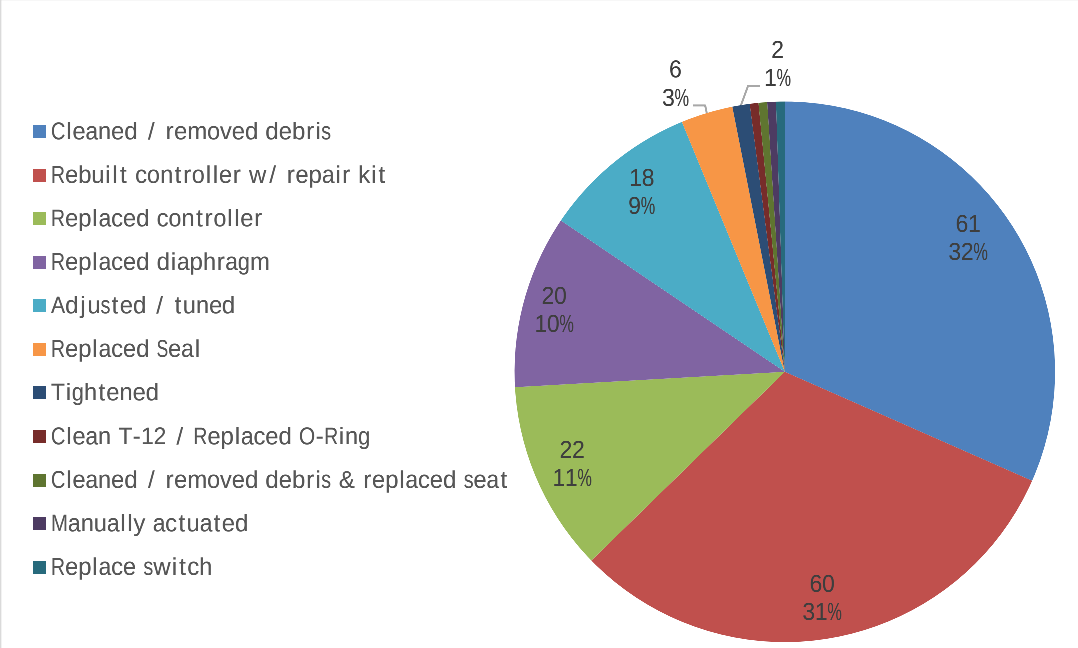
two PCs that needed repair were done on the same day of the inspection. 101 of the repairs were made at least a day later, with an average lag time of 4 days later.

Some repairs required a shut down or replacement of the PC. Those types of repairs take longer to complete and may have to be scheduled for repair soon thereafter or during the next planned shutdown of the facility. The majority of repairs were simply cleaning the PC and/or removing debris. Another common repair was to rebuild the PC with spare parts provided in a manufacturer repair kit.

Figure 6. PC repair actions



4.4.2 Midstream Data

As discussed previously, only two natural gas compressor stations of the 50 operated by participating companies use natural gas-driven PCs and were surveyed by the participating operator. All other natural gas compressor stations in the NAA owned by these participating operators utilized air-driven controllers and so therefore were not part of this study. The inspections of the two subject natural gas compressor stations occurred over two days in late August and early September. A total of 23 PCs were inspected. Four (4) models of PCs were documented. None of the surveyed PCs were found to be operating improperly. The PCs were used to monitor and control liquid levels and pressure.

4.5 PCTF Study Findings and Conclusions

The key findings and conclusions from the PCTF study are summarized below in narrative form. Additional findings are provided in the industry surveys of PC inspection costs and effectiveness, and use of no-bleed PCs, provided in Section 5.

4.5.1 Key Findings

PC Survey

- The most common manufacturers of PCs surveyed for this study were Kimray (43%), Wellmark (36%), and Fisher (15%).

- The most common models of PCs surveyed for this study were Wellmark 7400 Snaptrol (32%), Kimray T-12 (21%), Fisher 4660 (14%), Kimray 230 SGT (7%), Murphy LS200N (3%), and Norriseal 1001A (2%).
- Intermittent PCs comprise 84% and low bleed, continuous PCs comprise 16% of the 3838 PCs surveyed for this study.
- For equipment location, the PCs surveyed were found as follows:
    - 89% on separators
    - 8% on compressor engines
    - 1.4% on liquid knockouts
    - <1% on various equipment

PC Improper Operation

- The rate of PC improper operation varied:
    - by facility production:
        - Ranging from 5.1% for greater than 250 bbl/day, to 6.5% for 10-250 bbl/day, and 3.2% for 0-10 bbl/day.
    - by controller type:
        - 4.3% for pilot PCs and 8.0% for integrated PCs.
    - by controller vent type:
        - 5.3% for intermittent PCs and 3.4% for continuous PCs.
    - by controller enclosure:
        - 3.1% for enclosed PCs and 7.9% for non-enclosed PCs
    - by equipment location:
        - 4.9% for separators, 11% for compressor engines, 0% for liquid knockouts, and varying percentages for those few PCs that serviced various types of equipment.
- Overall, the observed rate of improper operation for all surveyed PCs was 5%.
- Actuations of PCs were observed only for 33% of the PCs surveyed.
- PC emissions were observed at the following locations and frequencies:
    - Vent port – 79%
    - Body – 20%
    - Vent port and body – 1%
- The following frequencies of common indicators of PC improper operations were reported.
    - 86% - Continuous bleed from vent port of intermittent PC
    - 11% - More venting than normal from continuous PC based on inspector's judgement
    - 1% - Continuous bleed from vent port of intermittent PC and PC was making unusual sound

Causes of PC Improper Operation

- The following frequencies of common causes of PC improper operations were reported:
    - Corrosion – 21%
    - Diaphragm failure - 20%
    - Seal failure – 19%
    - Debris – 18%
    - Other: Unknown - - 11%
    - Other: Vendor repair – 6%

- Other: Scrubber leaks – 2%
- Abnormal operations parameters – 1%
- Other: Wet supply gas – 1%
- Various - <1%

PC Repairs

- The following frequencies of common types of repairs of PCs that were not operating properly were reported:
  - Cleaned/removed debris – 32%
  - Rebuilt PC – 31%
  - Replaced PC – 11%
  - Replaced diaphragm – 10%
  - Adjusted/tuned PC – 9%
  - Replaced seal – 3%
  - Tightened – 1%
  - Various - <1%
- Double block and bleed was performed for 36% of the PC repairs.
- Equipment shutdown was performed for 37% of the PC repairs. Shutdown of a well was performed for 24% of the repairs.
- The time to make a PC repair varied by the type of repair, yet the average time for all types of repairs was less than 30 minutes.

4.5.2 Conclusions

This PCTF study represents the largest sample set of PC inspections in the nation to date, with 3838 PCs surveyed during the facility inspections conducted during the spring and summer of 2018. The 5% rate of improper PC operation found in the 3838 PCs inspected for this study based on emissions observed using an OGI camera demonstrates that typically (~95% of the time) PCs sampled in this study were found to be operating properly.

This study also demonstrated that an OGI camera can identify improperly operating natural gas-driven PCs. Detection of improper operation of an intermittent PC is largely determined by the observation of continuous emissions between actuations. Given that 84% of the PCs surveyed consist of intermittent PCs, the use of an IR camera is particularly effective in identifying excess emissions from intermittent PCs. Discerning improper operation of a low bleed continuous PC is less straightforward and is subject to the experience and judgement of the inspector in discerning excess emissions from improper operation.

Additionally, where an existing LDAR program exists for fugitive leaks, adding the inspection of natural gas-driven PCs to the inspections adds minimal incremental inspection costs. Repairs of improperly operating PCs are readily made by cleaning the PC of corrosion and debris, replacing broken parts and adjusting/tuning the PC and the supply gas pressure.

4.6 Separate EPA/CDPHE Study on PCs in Denver-Julesburg Basin

4.6.1 Overview

Over a similar time period as the PCTF inspection study, EPA and CDPHE conducted a parallel study on natural-gas actuated PC emissions in the DJ Basin. The results of this parallel study were published in early 2020 in the Journal of the Air and Waste Management Association in a paper by Stovern et al. entitled "Understanding oil and gas pneumatic controllers in the Denver-Julesburg basin using optical gas imaging."

Briefly, the Stovern et al. paper focused on a smaller sample size of PCs (500 controllers servicing 102 wells at 31 facilities operated by seven different companies) and included counts and observations of intermittent and continuous low bleed PCs. The PCs were inspected with OGI, and the emission rate from a small subset of the inspected PCs was quantified using high-volume sampling. Although measurements required to quantify actuation volumes were outside the scope of this study, the OGI camera survey provided limited information on the frequency of occurrence for actuations. This study was performed in the spring 2018 over a period of 10 field days.

4.6.2 Study Design

Stovern et al identify two objectives for this study: 1) gather information on the types and uses of PCs employed by randomly selecting facilities representative of the overall basin and 2) investigate the use of an expeditious and less invasive PC emissions survey approach based on optical gas imaging (OGI) camera that could help inform PC operational and maintenance states.

An important aspect of the PC survey was to confirm that the exhaust port of the PC was visible during the OGI inspection so that any continuous emission through the PC pilot could be assessed. A FLIR GF320 camera was utilized to monitor emission profiles of PC for this study, which has a normal or "auto" imaging mode and a high sensitivity mode (HSM), where onboard differential image processing can enhance an operator's ability to identify lower emission rates approaching 0.5 scf/hr natural gas or even lower under ideal conditions. Comparisons between the auto and high sensitivity mode imaging were made in monitoring PC emissions to explore their differences in detection capability as a rough indicator of emission level. An extended OGI observation time of 60 sec for each PC was used to enhance detection capability, to look for anomalous temporal emission profiles indicative of potential malfunctions, and to document short time duration PC actuation events as activity data where possible. If an actuation event or unusual temporal profile was observed, the observation time was increased to 120 seconds to bound actuation frequency and further diagnose potential malfunction issues.

The well production facilities ranged in production and complexity from small facilities with minimal equipment (such as one wellhead, one separator, and one or two tanks) to larger facilities with multiple wellheads, separators including second and third stage separation vessels, complex tank batteries with vapor capture systems, multiple control devices, gas lift compressor engines, and vapor recovery units. Of the 31 well production facilities selected, the wells were 50.0% vertical, 33.3% horizontal and 16.7% directional. This distribution is consistent with the overall well type distribution for the 24,220 actively producing wells in the basin of 42.1% vertical, 38.9% horizontal, and 19% directional.

Information gathered for each pneumatic system (PS)/PC included: process working status (in use or shut-in), PS/PC identification (make/model), motive gas type, PC configuration and operational mode, process function (control, safety, or both), process equipment application (separator, combustor, compressor, etc.), and sensed process variables (e.g. temperature, pressure, and liquid level). PC-specific information such as model configuration variables, retrofit status, installation date, actuator components, and supply line pressures were also documented to the extent possible.

4.6.3 Findings

Stovern et al. (2020) reported the following findings for the EPA/CDPHE PC study:

Survey of PCs at Facilities

- A total of 615 process control pneumatic systems (PSs) were found at the 31 facilities with 59 of these being of the electronic variety that does not use gas-emitting PC pilots.
- Of the 556 PSs with gas-emitting PC pilots, 38 of these were instrument air-driven. Natural gas was found to be the exclusive motive gas type at 30 of the 31 facilities surveyed. One facility used instrument air on 38 out of 52 PCs with the natural gas models at that facility primarily serving back pressure regulation functions. Operations of instrument air-driven PCs were not further studied by Stovern et al.
- Of the 518 natural gas-driven PCs, 18 (3.5%) of these comprised a "no-vent" design where the natural gas emitted from the pilot is fully captured. These integrated pilot-actuator PCs have the potential to emit natural gas only by diaphragm or connector leaks that would be classified as equipment leaks and therefore were not further studied by Stovern et al.
- A total of 500 natural gas emitting PCs were found at 31 facilities servicing 102 wells (average of 4.9 PCs/well).
- A total of 453 of the 500 natural gas-driven PCs were found to be in service (i.e. not shut-in or depressurized); this number represents the primary count of the PCs assessed for proper operation. Of this total, 377 (83%) of the PCs were intermittent and 76 (17%) were continuous.
- A total of 447 PCs were monitored with an OGI camera for emissions as six intermittent PCs were not surveyed due to wind speeds exceeding the 9 m/s method limit.

PCs with Maintenance Issues

- Of the 371 intermittent PCs monitored, 42 (11.3%) were observed with continuous emissions and 22 were observed with actuations (5.9%). This 11.3% represent intermittent PCs experiencing some level of maintenance issue. The severity of the maintenance issues is unknown without emission rate measurement. The authors note that due to the fact that some controllers were observed in the less sensitive "auto" mode of the OGI camera (see below), the true level of maintenance issues among the intermittent PCs they surveyed was probably higher. They estimate that the true frequency of maintenance issues in this population was 11.6 to 13.6%.
- Of the 76 continuous PCs, 28 (37%) were found to have continuous emissions. Yet, it is unknown what portion of these emitting continuous PCs reflect a potential maintenance issue, since they may have been operating as designed. As described below, at least one continuous PC had measured emissions above the State regulatory standard (6 scf/hr).
- It was critical to determine the design type of the PC (intermittent or continuous) during the on-site survey because the type assignment played a role in the assessment of potential maintenance issue conditions.

PC Emission Measurements

- Emission measurements were conducted on 18 total PCs (14 intermittent PCs and 4 continuous PCs) with continuous emissions detected during the OGI camera survey. In general, the measurements were conducted on PCs that appeared to have the most significant gas signature.
- 36.8% of continuous low-bleed PCs (28 controllers) had continuous emissions that were observable with the OGI camera. Emissions were measured from four of these continuous PCs with a high-flow sampler. Measured emission rates ranged from 0.7 to 9.9 scf/hr with an average ER of 4.2 scf/hr. Three of the continuous PCs exhibited emission rates above 1.39 scf/hr; one was considered to be malfunctioning as it was emitting in excess of the 6 scf/hr State regulatory limit. Two of the measured continuous PCs had measured emissions above 1.39 scf/hr and below 6 scf/hr.
- Snapshot measurements were conducted on 14 intermittent PCs that were observed using an OGI camera to have continuous emissions (not including actuations). Three of the measurements were near or below the estimated method detection limit of the technique at (0.1 scf/hr). Observed emissions rates ranged from 0.1 up to 31.3 scf/hr (mean = 2.8 scf/hr).
- In two cases, the intermittent PCs were cycling between actuations with the OGI camera video showing steadily increasing emissions prior to actuating, followed by a sharp drop in emissions below the OGI detection threshold. These significantly variable (heavy ramping and temporally sustained) emissions were categorized as maintenance issues for these snap-acting intermittent PCs.
- The highest measured intermittent PC emission rate (31.3 scf/hr) was caused by a process issue. This PC managed back pressure on the low-pressure side of a high-low pressure separator. A suspected process control issue was identified where a bleeding valve upstream of the low-pressure vessel caused the PC to continuously actuate because the low-pressure vessel was continually exceeding the pressure set point of the PC. In this situation, the intermittent PC itself was not malfunctioning.

Auto vs. High Sensitivity Mode

- The initial protocol for the OGI camera included evaluating only auto imaging mode (the less-sensitive mode for the OGI camera used in the study) at 85 PCs that serviced 26 wells at 9 facilities. Later, both high sensitivity mode (HSM) imaging and auto mode (HSM/auto) were used for most of the PC assessments (N= 362 PCs, 22 facilities, and 76 wells).
- The continuous PC emission detection rates for the auto-only versus the HSM/auto subgroups differed significantly. For the auto-only mode subgroup, 1 of 16 continuous PC (6.3%) and 1 of the 69 intermittent PCs (1.4%) exhibited continuous emissions. For the HSM/auto subgroup, 27 of 60 continuous PCs (45%) and 41 of 302 intermittent PCs (13.6%) exhibited continuous emissions.
- OGI camera imaging modes were observed to have a significant effect on emission detectability with HSM mode detection rates being approximately 2 times higher compared to auto mode.

Actuations

- A total of 33 actuation events (AEs) were observed from 22 different PCs in the 447 monitored for this study. Based on observed emissions, only a few percent of intermittent PCs in this basin appear to have actuation frequencies greater than 1/min, with many PCs (e.g. safety category) very infrequently actuating.
- AEs were observed at only 9 of 31 facilities with the top two highest oil producing facilities accounting for 54.5% (12 of 22) of the PCs with actuations. The highest producing facilities had five separate intermittent PCs exhibiting AEs with a total of 13 observed, whereas the second-highest producing facilities had 7 PCs and 8 total AEs. There were a total of six PCs surveyed that had multiple actuations observed during the OGI survey (extended up to 2 min). Three of those PCs were located at the highest producing facility, and one PC with multiple actuations was located at the second, fifth, and sixteenth highest producers.
- The OGI camera survey indicates an expected relationship between normalized oil production and observed actuations. At a high producing facility, the same PC and process will require more actuations than at a lower producing facility. However, PCs with a maintenance issue do not show the same correlation with facility production.
- Estimated actuation volumes ranged from 0.005 to 0.185 scf per actuation event, which indicates that potential emissions from continuous emissions due to a maintenance issue may often be the dominant factor in overall emission rates for infrequently actuating PC populations. At lower producing facilities, the continuous emission component of emissions for intermittent PCs with maintenance issues becomes a more significant factor affecting average PC emissions rates for lower producing facilities.

4.6.4 Conclusions

- Although the findings of this study are representative of the DJ Basin, they are not intended to be representative of PC operating characteristics at a national level and therefore should be used with caution at that scale.
- The observed PCs per well are reasonably consistent with the 2018 data from EPA's Greenhouse Gas Reporting program for the Denver Basin with an average of 3.1 PCs per well and are significantly higher than the national average of 1.6 PCs per well (U.S. EPA 2019c).
- 83% of the PCs surveyed for this study were intermittent PCs, which is consistent with the 91% reported by Allen et al. (2014) for PCs in the Rocky Mountain region.
- The use of an OG camera to profile PC emissions was found to be a helpful approach to inform PC maintenance issues.
- Observing continuous emissions from a PC with an OGI camera on a snap-acting intermittent PC is indicative of emissions beyond the designed shut-off rate and is indicative of a maintenance issue.
- The identification of actuation events for continuous PCs and throttling process control applications was more challenging than those for intermittent PCs in snap acting applications.
- For a low bleed CPC, continuous emissions observed with an OGI camera was not informative to detect a potential maintenance issue unless in the OGI operator's judgment the emission appeared abnormally large compared to typical operation.
- 11.3% of intermittent PCs surveyed were directly observed with OGI to have continuous emissions. Due to an issue with the use of the OGI camera at some sites, this figure probably represents an underestimate of the frequency of continuous

emissions from these controllers. Stovern et al. estimate that the true frequency of continuous emissions in this population was 11.6% to 13.6%. These observations may reflect maintenance issues since these emissions were likely above the designed seepage rate of these intermittent PCs.

- As opposed to intermittent PCs, it is unknown what portion of continuous PCs were experiencing a potential maintenance issue, without measurement. One of the four continuous PCs measured was classified as malfunctioning with a measured emission rate of 9.9 scf/hr, above the 6.0 scf/hr State regulatory limit.
- The type of imaging mode (i.e. auto vs high sensitivity) utilized during the OGI camera survey was observed to significantly affect the detection rate of continuous emissions. The detection rate of continuous emissions using high sensitivity mode was 1.6 and 2.1 times higher than when using auto-mode imaging for intermittent PCs and continuous PCs, respectively. The difference between observation capabilities in high sensitivity vs. auto modes could be used in an inspection approach to approximately separate the PC populations (e.g. minor maintenance issues and significant malfunctions), so that repairs can be prioritized to minimize unnecessary emissions.
- PC actuations from process control-based PCs correlate with facility production. Facilities with lower production will have lower actuation emissions rates among its PC population and continuous emissions from PCs with maintenance issues will therefore be the controlling factor for the average operational PC emission rate. For higher producing facilities that cause PCs to actuate much more frequently, actuations will be a significant contributor to the overall average operational PC emission rate

4.7 Comparison of PCTF Study and EPA/CDPHE Study Findings and Conclusions

The following statements offer key comparisons between the findings and conclusions for the PCTF Study and EPA/CDPHE Study.

4.7.1 Findings

- Both field inspections of PCs were conducted in the DJ Basin during the spring/summer of 2018.
- Both studies focused on identifying improper operation (aka maintenance issues) of PCs using an OGI camera by trained and experienced personnel during facility inspections.
- Facility selection for each of these studies was done randomly for the operators participating in each study.
- Both studies found that the majority of natural gas-driven PCs observed consisted of intermittent PCs (PCTF – 84% vs EPA – 83%)
- The EPA/CDPHE study estimated that 11-14% of the intermittent PCs inspected were not operating properly, while the PCTF study found 5.3% of intermittent PCs were not operating properly.
- The EPA/CDPHE study found that using a camera in high sensitivity mode was more effective in finding smaller emissions from intermittent PCs.
- The EPA/CDPHE study did not evaluate whether continuous PCs were operating properly based on emissions observed with an OGI camera. The PCTF study found 3.4% of continuous PCs were not operating properly. Emissions measurements were performed by EPA/CDPHE on four continuous PCs, finding one of these PCs to have emissions in excess of the 6 scf/hr regulatory limit.
- The EPA/CDPHE study measured 14 intermittent PCs that were observed using an OGI camera to have continuous emissions. Observed emissions rates ranged from 0.1 up to

31.3 scf/hr. The elevated reading of 31.3 scf/hr was attributed to a process issue and not PC improper operation.

A significant contrast between the PCTF study and the EPA/CDPHE study is related to how integrated pilot-actuator devices were classified. Simpson (2014)[6] defines an *integral* PC as a PC that is built into an end device (i.e. valve) and does not require an external source of gas, nor does it release actuation gas to the atmosphere. Rather, it releases actuation gas into the process downstream. Similarly, Simpson defines a *local* controller is also defined as one built into the end device, but it exhausts gas to the atmosphere to move the process valve toward closed. In contrast, remote pilot controllers are PCs that are not integrated into the end device.

Note that "integral" controllers, as defined by Simpson, would be considered "Self-contained PCs" under Regulation 7. Additionally, note that Stovern et al. refer to both integral and local PCs as "integrated" PCs, and they use the term "no-vent" for PCs that Simpson defines as "integral" – those that release gas into a process downstream. The discussion below uses Simpson's terminology.

- The EPA/CDPHE study did not include integral devices in their assessment of PCs. EPA stated in its report that integral PCs have the potential to emit natural gas only by diaphragm or connector leaks and that any such leakage should be classified as an LDAR component leak, rather than as a PC that is operating improperly.
- For the PCTF study, integral devices were classified as a type of PC. 59 (8%) of the 740 integral PCs surveyed were determined to be not operating properly, compared to 134 (4.3%) of the 3,098 pilot PCs surveyed. Presumably, these devices were leaking from the diaphragm or connector, as described above.
- Since the PCTF study included integral controllers, while the EPA/CDPHE study did not, and integral controllers were operating improperly at a relatively *high* rate in the PCTF study, this suggests that the inclusion of integral controllers in the PCTF study skewed the improper operation rate slightly higher.
- Regardless if classified as a PC or not, integral controllers are included as a component in a LDAR program for equipment leaks and will therefore be assessed for leakage and repaired as needed to ensure proper operation.

4.7.2 Conclusions

- The Stovern et al. study found that using the high sensitivity mode of the OGI camera resulted in a nearly 2 times higher emission detectability compared to the auto mode. This might explain why Stovern et al found more than twice the percentage of intermittent PCs that were not operating properly compared to the PCTF study (11-14% vs 5%).
- The Stovern et al. study used a set observation time of 60-120 seconds for every PC/PS. The PCTF study did not have this requirement and if the OGI camera operator did not detect emissions within a few seconds, they would move on with the inspection. These varying approaches were utilized because each study had a different objective. The PCTF study set out, in part, to determine the effectiveness of the find and fix program, so inspection protocols were adapted to current industry practices.

[6] Simpson (2014), *Pneumatic Controllers in Upstream Oil and Gas*. https://pubs.spe.org/en/ogf/ogf-article-detail/?art=238.

The longer observation time used by Stovern et al. may also be a contributing factor to the discrepancy between the proper operation rates.

- Both studies concluded that using an OGI camera to profile PC emissions was an effective method to inform possible improper operation of intermittent PCs. However, the use of this method for identifying improper operation of continuous PCs is more challenging, except when the emissions appear to be abnormally large compared to normal operation.

5 Industry Surveys

In order to achieve the goals established by the PCTF for reassessment of the Find and Fix program, additional information needed to be gathered on the effectiveness and costs related to inspection of PCs under the find and fix program and to better understand the use of self-contained and no bleed PCs. A series of questions were developed and incorporated into survey questionnaires that operators were requested to complete. A total of three surveys were developed:

1. The effectiveness and costs of PC inspection techniques
2. The effectiveness and costs of PC repairs
3. The use of self-contained and no bleed PCs.

The surveys were completed in confidence, and then blinded and compiled by API and COGA to address industry anti-trust concerns before being shared with the PCTF in presentations that summarized the survey responses. The first two surveys were to be completed by the nine operators participating in the PCTF study within the ozone NAA. The third survey was distributed to COGA and API members with oil and gas production operations in the state. As described below, the second survey was developed but not completed.

5.1 Effectiveness and Costs of Inspection Techniques (NAA only)

Highlights from the results of survey questions provided to the nine operators participating in the PCTF study on the effectiveness and costs of PC inspection techniques are provided in the following bullets.

- The majority of operators use a combination of employees and contractors to conduct PC inspections. Some operators use employees only.
- The majority of operators use the same party for both LDAR and PC inspections.
- Operators typically conduct LDAR and PC inspections during the same facility visit.
- Operators generally replied that it can be helpful to know in advance whether the PC is an intermittent or low bleed in order to understand if emissions are expected between actuations (low bleed) or not (intermittent).
- Operators also indicated that understanding the process the PC is controlling is beneficial in making a determination whether a PC is operating properly or not.
- For intermittent PCs, operators typically look for continuous emissions between actuations. For continuous bleed PCs, operators typically look for emissions that appear abnormal for that type and application of controller.
- Operators found using OGI camera inspections along with AVO indicators was effective, although OGI cameras are more effective at finding smaller leaks. Soapy water may be used to further pinpoint a leak location.

- AVO indicators such as the presence of liquids at or around/below the vent and whether dependent processes are operating properly can be useful to determine whether a PC is operating properly or not.
- Safety limitations in the use of OGI cameras are largely driven by whether the OGI camera is intrinsically safe or not. An intrinsically safe camera does not pose a potential ignition source and can be used in Class 1 Division 2 areas as defined by OSHA in CFR 1926.449. OGI cameras that are not intrinsically safe may require a hot work permit to be allowed on site at a facility or the camera operator may have to maintain a minimum safe distance from the equipment being observed.
- Responses on the average time to inspect a PC varied depending on the experience of the inspector and included various caveats including weather conditions. The inspection time varies and is dependent on the type of PC and if emissions are observed. If no emissions are observed, then only a few to several seconds is generally sufficient to determine that the controller is operating properly. If emissions are observed, then the time to make this determination is dependent on whether the controller is actuating or not, the type of controller, and the characteristics of emissions observed. It could take up to several minutes to make this determination.
- The costs to conduct PC inspections are variable and likely highly dependent on the size and makeup of facilities of operators and internal programs and processes. Some operators indicated that the incremental equipment costs are not significant since this equipment is required for LDAR inspections. Other operators estimated that incremental annual equipment costs for PC inspections represent a small percent of LDAR related equipment costs. Ultimately, incremental annual equipment costs for PC inspections are dependent on the number of PC inspections performed.

5.2 Effectiveness and Costs of Repairs (NAA only)

Due to the need to focus on regulatory proposals to be considered for the December 2019 AQCC rulemaking, and the willingness of operators to expand the PC “find and fix program” statewide, it was not necessary to complete the planned repair cost survey.

Separately, the PCTF study results indicated that those PCs found to be improperly operating were successfully repaired and the majority of repairs were completed either immediately, the same day of the inspection, or within a few days of the inspection.

Operators seek to repair PCs in order to return them to proper operation since it is in their interest to maintain and optimize production operations. The cost of repairs is considered a normal operation and maintenance cost. The ability to more readily identify PCs that are not operating properly using an OGI camera allows earlier detection of those PCs needing repair that would otherwise eventually fail to control their intended process function and need subsequent repair.

The repair costs range in regard to the extent of the repair. These repairs can range from cleaning the PC of debris or residue that collects over time, replacing worn parts, or replacing the entire controller. Operators stock spare parts, repair kits or extra PCs that are then used to repair or replace the defective PC as a means to promptly make a repair.

The costs of repairs was not considered an impediment to supporting expansion of the PC “find and fix” program from the NAA to statewide during the AQCC December 2019 rulemaking.

5.3 Use of Self-contained and No-Bleed PCs (State-wide survey)

COGA developed and distributed a survey to better understand the use of self-contained and no-bleed PCs. The survey utilized the following definitions in order to establish a common understanding in completing the questions.

- Instrument air-driven PC: Any PC that is uses compressed air as the valve's actuating gas. Known as “no-bleed” under CO Regulation 7.
- Natural gas-driven PC with exhaust routed to process/sales: Any PC that directs gas to a process or sales line instead of to the atmosphere. Known as “self-contained” under CO Regulation 7.
- Natural gas-driven PC with exhaust routed to combustion control: Any PC that directs gas to a combustion control device instead of to the atmosphere.
- Non-pneumatic mechanical controllers: Any controller that uses mechanical force (not a pressurized gas) to trigger actuation.
- Non-pneumatic electric controllers: Any controller that uses an electrical signal (not a pressurized gas) and motor to trigger actuation.

The survey results are summarized below:

- 12 Operator Responses for production facilities
  - 3 Operators in Piceance, 9 in DJ.
    - >5,400 Total Production Facilities: ~4,200 DJ NAA, ~100 DJ AA & ~1,200 Piceance
    - >22,400 total wells: ~15,700 DJ NAA, ~500 DJ AA & ~6,200 Piceance
    - Percentage of facilities where on-site electrical grid power is used:
      - 19% DJ NAA
      - 63% DJ AA
      - 4% Piceance
- Operator Responses for compressor stations
  - 4 Operators in Piceance, 1 in DJ responded.
    - 16 Compressors stations in DJ NAA, 38 in Piceance
    - Percentage of compressor stations where on-site electrical grid power is used:
      - 100% in DJ NAA
      - 76% in Piceance
  - DJ NAA - 1 operator
    - 16 compressor stations
    - All use instrument air-driven PCs (11 new, 5 retrofitted)
  - DJ AA - No compressor station operator responded
  - Piceance Basin - 4 operators responded
    - 38 compressor stations
    - 9 new stations use instrument air-driven PCs
- Summary of Usage
  - The majority of PCs in use in Colorado are conventional natural gas-driven PCs
  - Most of the non-conventional controllers in use in the state are located
    - In the DJ NAA
    - At new facilities receiving production from horizontal wells
  - The most commonly used non-conventional controllers are air-driven PCs
  - Other non-conventional controller technologies usually only replace a fraction of the PCs at a site

- Consideration for Use
  - Safety
    - Instrument air-driven PCs
      - Some operators expressed concern with facilities using both instrument air-driven and natural gas-driven PCs: potential risk of flammable mixtures or explosion
      - One operator noted that fail-safe close valves need to be used so the site/well can shut-in in case of power loss or air compressor malfunction
    - Natural gas-driven PC with exhaust routed to process/sales or to combustion control
      - The required additional piping/plumbing could significantly complicate work areas
      - There are backpressure issues with remote PCs preventing exhaust vapors from reaching process/sales or combustion control
      - Backpressure can also slow actuation and affect operation
    - Non-pneumatic mechanical controllers
      - Some operators indicated mechanical dumps are more prone to failure due to erosion.
      - One operator noted that mechanical dumps may not have emergency shut down ability.
    - Non-pneumatic electric controllers
      - It was noted electrical controllers may not have a fail-safe capability and do not return to a safe position when power is lost, unlike conventional natural gas-driven PCs. Electric fail safe close valves require programming.
      - Electrical classification determines safe location on site.
    - Overall
      - Non-conventional have a positive impact on safety by reducing the quantity of hydrocarbon vapors in the atmosphere at facilities.
  - Costs
    - Instrument air-driven PCs
      - New facilities: incremental capital cost of \$70K - \$140K (depending on production/number of wells)
        - Additional piping, air compressor, supporting infrastructure, grid power/generator.
        - Use of grid power is critical for most, generators also used by some.
        - Additional maintenance costs required for air compressor and a desiccant air dryer.
        - One operator reported reduced maintenance on instrument air-driven PCs themselves.
        - One operator mentioned a backup instrument gas may be required, increasing costs.
      - Existing facilities: incremental capital cost of \$90K - \$180K (depending on production/number of wells)

- Several operators reported that, due to declining production, retrofits are not cost effective and have primarily been done under compliance order.
        - Loss of production for retrofit, in addition to reasons listed above.
        - Additional incremental cost is on top of the initial cost to run instrument gas line.
        - One operator reported the need to hydro vacuum instrument air lines before retrofitting
  - Natural gas-driven PC with exhaust routed to process/sales
    - Significant cost associated with design of a complex vapor capture system.
    - Cost associated with compression to safely and reliably get emissions into process lines.
    - Additional maintenance on vapor control system (VCS) lines.
  - Natural gas-driven PC with exhaust routed to combustion control
    - Cost associated with re-piping equipment. May be do-able for PCs in close proximity to control device, very high cost otherwise.
    - VCS: Additional maintenance on lines and may require updates to the VCS analysis.
    - Some compressor stations are not equipped with ECD: high cost for low reductions.
  - Non-pneumatic mechanical controllers
    - Some mechanical dumps usually have lower upfront cost but higher maintenance cost.
    - For retrofits, cost of new controllers when natural gas-driven controllers are already in use.
  - Non-pneumatic electrical controllers
    - One operator reported an incremental cost of $7K - $10K per well.
    - Controllers have a higher upfront cost and higher maintenance cost.
    - Several operators reported that retrofits are not cost effective.
- Technical
  - Instrument air-driven PC
    - Sufficient grid power availability (true for new and potential retrofits).
    - Very frequent maintenance on air compressors required to ensure reliability.
      - One operator noted liquid collection and freezing may require backup compressors.
    - Considerations for power loss:
      - Some operators do not have back up options and site shuts in.
      - One operator reported using natural gas powered back up air compressors.
      - One operator reported using pressurized air bottles.
  - Natural gas-driven PC with exhaust routed to process/sales

        - Low pressure and low volume gas needing compression to process/sales.
        - Concerns with vapor collection lines such as air intrusion through components, debris and/or condensate build up, freezing, and backpressure concerns.
        - Not all exhaust from natural gas-driven PCs can be captured.
    - Natural gas-driven PCs with exhaust routed to combustion control
        - Low pressure and low volume may make it difficult for gas to reach combustor.
        - One operator mentioned experience indicating back pressure which affects valve actuation and maintaining stable stream to the combustor.
    - Non-pneumatic mechanical controllers
        - Generally can only replace a specific type of PC: dump valves/liquid level.
        - Experience shows that mechanical controllers are not as precise or as reliable as natural gas-driven PCs for process control.
    - Non-pneumatic electric controllers
        - Need for reliable electrical power (e.g. solar with battery and generator/grid as backup).
        - There are no electric replacement options for some natural gas-driven PCs.
        - There are limitations on where those controllers can be located (e.g. not compressors).
        - Electric fail safe close valves requires programming knowledge.
- Land/Leasehold
    - Instrument air-driven PCs
        - Ability to bring grid power may be limited: landowner restrictions, BLM land & FS land with approval requirements, remote/mountainous locations.
        - Pad size needs to be sufficient to accommodate air compressor and additional infrastructure in an area that is safe for electrical equipment.
            - Especially challenging for existing facilities where land has already been reclaimed.
    - Natural gas-driven PC with exhaust routed to process/sales or to combustion control
        - None identified
    - Non-pneumatic mechanical controllers
        - None identified
    - Non-pneumatic electric controllers
        - None identified
- Other
    - Instrument air-driven PCs
        - Pros:
            - Instrument air-driven PCs are a proven technology and usually use same/similar PCs.
            - Instrument air-driven PCs are not subject to the find and fix program.

- Reg. 7 requires the use of no-bleed (instrument air-driven PCs) at facilities that use grid power.
- Cons:
  - Grid power availability is utility dependent and can be very complex (permitting and approvals for new lines, proximity to power line does not mean availability).
  - Electric generators, if used, require permitting through APCD and have extra emissions.
  - Retrofits are not cost effective and primarily been done under compliance order.
- Natural gas-driven PC with exhaust routed to process/sales
  - Reliability (operation and maintenance very complex). Other options are more desirable.
  - Required by Reg. 7 once grid power is used on site and if technically and economically feasible.
  - Process/sales gas line occasional downtime may require redundancy.
  - Emissions associated with required additional compression.
- Natural gas-driven PC with exhaust routed to combustion control
  - Not considered as no-bleed or self-contained under Reg. 7 definitions.
  - Reliability is a major concern: other options are more desirable.
- Non-pneumatic mechanical controllers
  - None identified
- Non-pneumatic electric controllers
  - One operator reported less maintenance needed for such controllers.
  - Not a proven technology, cannot cover all functions usually covered by natural gas-driven PCs.
  - Use and maintenance requires staff with knowledge related to electrical systems.

- Survey Takeaways
  - Fail-safe options a concern for non-natural gas-driven technologies
  - Instrument air-driven PCs
    - Electrical grid power use is crucial, upfront cost is high
    - Proven technology, familiar make/model of PCs, less training
    - Safety and cost effectiveness concerns for retrofits
  - Natura gas-driven PCs with exhaust routed to process/sales/control
    - Operationally burdensome, reliability issues
    - Only feasible for a small subset of PCs
  - Mechanical controllers
    - Can only replace very specific functions (dump valves)
    - Cheaper upfront
    - Reliability and precision concerns
  - Electrical controllers
    - Require reliable power
    - Require trained staff
    - Only feasible for a small subset of controllers

According to the industry survey on zero-emitting PCs, the practice of capturing gas and routing emissions from a self-contained PC to emission control devices (ECD) is relatively uncommon and is highly dependent upon the distance between the vent port of the PC and the ECD. The PCTF study identified 50 PCs where PC vented emissions were routed to a nearby ECD. All of these PCs that were routed to an ECD were operating properly. The majority of these 50 PCs serviced a level control for a liquid condensate burner knockout pot which was located within a few feet of the ECD. In most cases, these knockout pots are drained by gravity or manually and are not controlled by a PC.

Routing to a process is relatively uncommon due to pressure differences between the vent port and the process. In general, the gas pressure from the vent port is too low to route to a facility process.

The category of no-bleed PCs can be considered a misnomer as all "pneumatic" controllers bleed or vent as part of their normal operation. The term "no-bleed" usually refers to those PCs that use instrument air as a motive force, rather than natural gas. In order to utilize instrument air, an air compressor, desiccants and filters, and pressure regulators are typically installed. The power to operate the air compressor is either provided using an electrical generator that is fueled by natural gas or diesel, or by a connection to an accessible utility line that provides adequate electrical power to the facility. The use of a natural gas or diesel fuel powered generator may result in a net emissions disbenefit in providing instrument air in lieu of natural gas for operating PCs. However, the net emissions benefit or disbenefit would vary on a case-by-case basis.

(Note that low power air compressors designed driving pneumatics using solar-battery systems for electricity,[7] and hybrid solar-gas powered electric compression systems,[8] are both available on the market in Canada.)

For new development of multi-well pads, operators pursue commitments from electric utilities to provide a connection and adequate power to a planned facility for electrification of equipment including air compressors for instrument air. A number of factors, many of which are beyond the operator's control, dictate whether the utility can provide an accessible connection and adequate power when the facility is being constructed. If the utility is not capable of meeting the requested commitment, then the operator will typically either rely on a natural gas or diesel-fired generator to power an air compressor, or utilize natural gas pressure as a conventional power source for PC operation.

5.4 Electrical Infrastructure for Oil and Gas Development

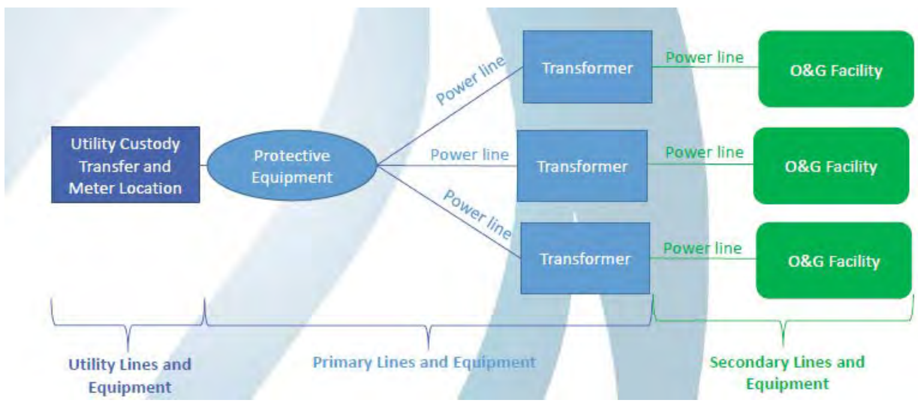
As part of the joint effort with the SHER work group, information was collected from API and COGA operators regarding the availability and planning for the use of electrical power from the grid or the use of natural gas or diesel oil powered generators to provide electrical power at oil and gas production facilities. A presentation was given during the July 12, 2019, SHER meeting which included the following talking points:

- Urban growth and development is an issue and impacts infrastructure availability

[7] See https://lcotechnologies.com/crossfire-compressor.html.
[8] See https://westgentech.com/.

- Federal Lands and The National Environmental Policy Act (NEPA)/ The Federal Land Policy and Management Act (FLPMA) processes in remote areas are also obstacles to the use of electrical grid power
- Colorado has public utilities and cooperatives that provide power:
  - o Each utility has different power drop timelines (1-3 years)
  - o Each utility has different requirements on ownership and installation requirements between primary and secondary power lines and equipment
  - o Primary lines are typically higher voltage lines while secondary lines are supplying power to a location (480-120 volts)
- Primary Meter – primary and secondary lines and equipment after custody transfer are installed, owned, operated and maintained by the company. In this case the O&G Facilities owner.

Figure 7. Primary Meter Ownership



- Secondary Meter –Only secondary lines and equipment after custody transfer are owned, operated and maintained by the O&G Facility owner. Everything upstream of custody transfer is installed, owned and operated by the utility.

Figure 8. Secondary Meter Ownership

- Primary Metering
  - o The company has the staffing and technical ability to install, own, operate and maintain all the electrical equipment
  - o Shorter lead times for power drop because less line and equipment needs to be installed by the utility
  - o Higher costs for companies that only have a few O&G facilities in an area that requires power
  - o Lower cost for companies with many O&G facilities in an area that requires power
  - o Might not be an option because of right-of-way and surface user agreements

- Secondary Metering
    - o Longer lead times for power drop to wait for utility to install primary lines and equipment
    - o Costs may be higher depending on the location and amount of power needed
    - o Some utilities require companies to perform primary metering so this might not be an option
- Challenges include:
    - o Slowdowns from utility companies due to increased residential development
    - o Changes in schedule from drilling permit issuance delays, operator agreement challenges with local governments, or right-of-way changes
    - o Can be limited by proximity and capacity of grid power depending on utility
    - o Power plant expansions dependent on air and other permitting
    - o Cost may be prohibitive for operators in limited development areas
    - o Small operators may not be able to effectively negotiate cost and availability
    - o Contractual third party agreements may limit operator access
    - o Timing often uncertain and power generation needed as backup

6 Good Engineering and Maintenance Practices

In 2017, the AQCC adopted Regulation 7 Part D, Section III.F.1. (formerly Section XVIII.F.1), requiring operators to operate and maintain PCs consistent with manufacturer's specifications, if available, or utilize good engineering and maintenance practices. The SBAP recognizes the need to more fully develop and document those practices, which include but are not necessarily limited to, ensuring proper operation. Data collected by the PCTF can be used to develop and document good engineering and maintenance practices.

Due to the unavailability of documentation from PC manufacturers, there are no widely agreed upon routine or preventive maintenance schedules. Individual operators have developed their own maintenance and operating plans in accordance with industry best practices and Regulation Number 7 requirements. While individual operators may have company-specific protocols for their PC program, all operators are in agreement on some key practices. The use of OGI cameras as the proper inspection tool to identify improperly operating PCs is universally accepted, at this time, by all industry members of the PCTF. However, identification of improper operation from a continuous low-bleed PC may require additional training/experience for the OGI camera operator. The findings above from the survey results on PC inspections also reflect key practices.

There are some barriers to developing prescriptive PC protocols because of the wide variability in how these devices function and the wide variety of designs and specific applications that are employed. More work needs to be done if developing prescriptive maintenance protocols is a goal of the AQCC.

6.1.1 <u>The Environmental Partnership</u>

API established The Environmental Partnership (TEP) in 2017 to "continuously improve the industry's environmental performance by taking action, learning about best practices and technologies, and fostering collaboration in order to responsibly develop our nation's essential natural gas and oil resources." TEP's initial focus is to further reduce the industry's air emissions in continuing to reduce methane, a greenhouse gas, and VOCs, which is one precursor to the formation of ground-level ozone. TEP hosted their first annual conference in

2018 as described in their 2019 Annual Report[9]. The conference focused on PCs and brought together producers, manufacturers, researchers, and regulators to discuss PC technology and how it might be improved.

In addition to periodically checking for proper operation of the controller through AVO and AIMM inspections, operators participating in this study concur with the "Pneumatic Controller Maintenance Work Practices" published by TEP as a wallet card for its members to provide to field personnel responsible for inspecting and maintaining PCs for proper operation of oil and gas production facilities. This wallet card is shown below:

7 Recommendations

The PCTF offers the following recommendations for consideration by the AQCC. Where there was not consensus on specific elements assigned to the PCTF, individual stakeholder positions are presented as such.

7.1 Effectiveness of current program (NAA only)

Pursuant to AQCC Reg 7 CTG rulemaking in November 2017, the PC find and fix program that applied only to the ozone NAA took effect on June 30, 2018, which was during the same summer of the PC field surveys performed for the PCTF study. The PC find and fix program has proven effective as demonstrated in the Division's 2018 LDAR Annual Report[10], which included the results of the PC find and fix program for the NAA, as described below. The AQCC extended the PC find and fix program state-wide effective May 1, 2020, as part of the AQCC SB-181 Reg 7 rulemaking in December 2019.

[9] See https://www.api.org/~/media/Files/Policy/Environment/TEP/The-Environmental-Partnership-Annual-Report-2019.pdf
[10] See https://www.colorado.gov/pacific/cdphe/2018-ldar-annual-reports-regulation-7-section-xii-xvii-and-xviii

The Division's 2018 LDAR Annual Report (pp. 4-6) summarizes the results of PC inspections performed for the PC find and fix program. Although the report does not break out the number of PC inspections using AIMM at well production facilities that were performed in the NAA in 2018, a total of 4,053 PCs were found to need repair and of these 4,015 (99%) were returned to proper operation. For natural gas compressor stations subject to PC inspections using AIMM in the NAA in 2018, a total of 7 PCs were needed to be repaired and 6 (86%) were returned to proper operation. Upon discovery of an improperly operating PC, repairs must begin no later than five working days and the PC must be returned to proper operation no later than 30 working days. A delay in a repair may be attributed to unavailability of parts, the equipment requires a scheduled shutdown to complete the repair, or other good cause. The Division developed a list of standardized enhanced response actions to repair PCs with input from the oil and gas industry to be used for recordkeeping and annual reporting purposes. These include the following options to return a natural gas-driven PC to proper operation:

1. adjusted/tuned;
2. cleaned/removed debris;
3. tightened;
4. heated/insulated;
5. replaced part(s) of controller;
6. rebuilt controller with repair kit;
7. replaced controller; and
8. other.

Below is Figure 2 from the Division's 2018 LDAR Annual Report that shows the distribution of each type of response action, with a total of 4,060 actions reported. The two most common types of response action were to clean/remove debris, and to rebuild the pneumatic controller with a repair kit.

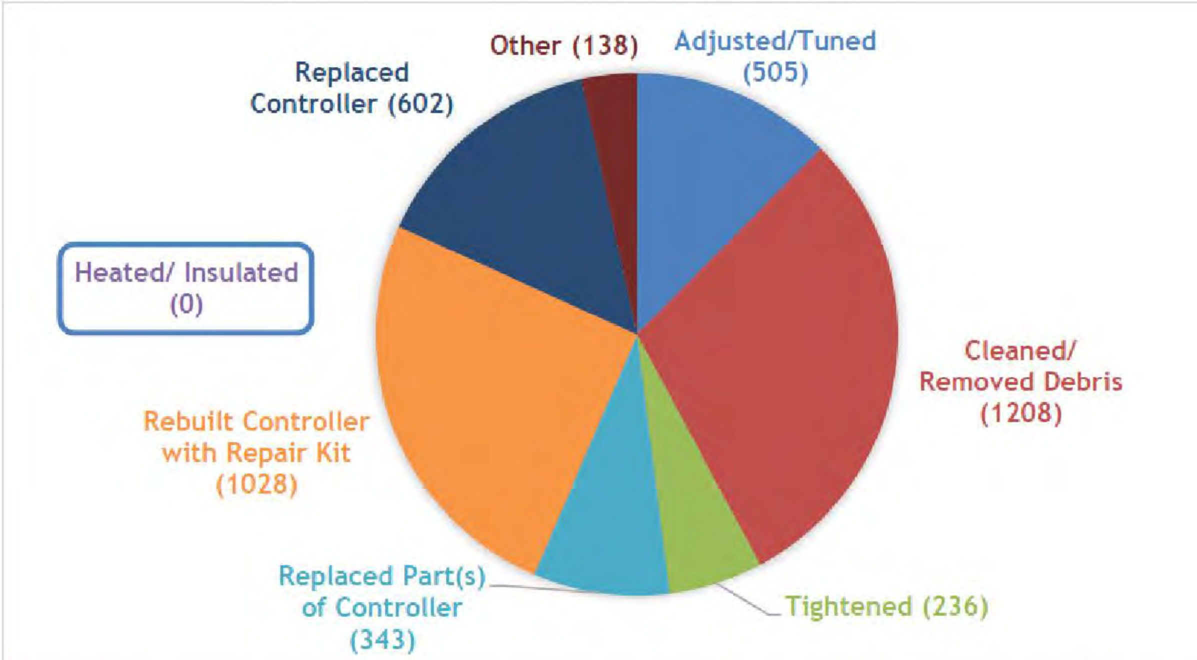


Figure 2: Enhanced response actions taken to return pneumatic controllers to proper operation, by enhanced response action category

Although not specific to natural gas-fired PCs, the Division's 2018 LDAR Annual Report on p.4 indicated that the use of an OGI camera was more effective than AVO observations during facility inspections for emission leaks from components. On page 4, the report states:

"Based on the data reported by owners/operators, more than 90% of leaks were identified through AIMM inspections despite AIMM inspections constituting only 3% of the total number of inspections at WPFs. While AVO inspections are valuable for operations and maintenance purposes, as well as being required by other sections of Regulation No. 7, the data from this year's LDAR annual reporting indicate that AIMM is a more effective monitoring method than AVO for detecting leaks."

Given the results from the 2018 PCTF field inspections, and the 2018 LDAR program and PC find and fix results, the PCTF believes the use of AIMM inspections using an OGI camera is an effective means for identifying both those emissions from PCs that indicate improper operation and from leaky LDAR components.

7.2 Definition Appropriateness

As discussed previously, due to the need to focus on regulatory proposals for consideration during the AQCC December 2019 rulemaking hearing, the PCTF did not complete its evaluation of the appropriateness of the current Reg 7 definitions related to PCs. However, revisions to these definitions will be included in the regulatory proposal specific to the use of no-bleed PCs (aka zero-bleed PCs). Currently, industry is developing a proposal that may be further modified through a future stakeholder and rulemaking process.

Stakeholder meetings will be scheduled and facilitated by the Division staff to review and solicit comments on the no-bleed PC regulatory proposal, which will include the need to make appropriate revisions to PC-related definitions. As such, for the purposes of completing this report, the PCTF does not recommend making any changes at this time to the definitions for "enhanced response", "intermittent pneumatic controller", "no-bleed pneumatic controller", "self-contained pneumatic controller", or "pneumatic controller". Changes to these definitions will be considered separate from this report in vetting the regulatory proposal with stakeholders.

7.3 No-bleed and Self-contained PCs

As defined by Regulation 7 Part D Section III., a no-bleed PC is "any pneumatic controller that is not using hydrocarbon gas as the valve's actuating gas." Alternative actuating gases include compressor air or nitrogen, but in practice such PCs in Colorado are mainly compressed air, also known as instrument air. Instrument air systems utilize a skid-mounted compressor and often come with a dryer system to remove moisture from the air prior to compression. Once compressed, the air is routed through the same supply gas system that would otherwise contain pressurized natural gas to actuate the PCs.

As defined in Regulation 7 Part D Section III., a self-contained PC is "a pneumatic controller that releases gas to a process or sales line instead of to the atmosphere." Such PCs utilize natural gas as the actuating gas, but have minimal emissions to atmosphere because the vent port of the controller is routed back to a process line. Likewise, although not addressed in the current Regulation 7 rule language, emissions from the vent port of the PC can be routed to a control device in some limited applications. As previously mentioned and further discussed below, the use of self-contained PCs is very limited due to technical infeasibility, safety concerns, and cost.

Additionally, mechanical or electric controllers (non-pneumatic) can be used in some very limited applications as described below. These controllers are neither no-bleed or self-contained as defined by Regulation 7 and because they have no emissions, are not subject to the regulatory requirements. However, the PCTF included these controllers in the operator survey so they are also addressed below.

<u>BCPH, DDPHE, and CC4CA Position:</u>

SB181 directed the AQCC to consider a requirement to reduce emissions from pneumatic devices and in 2019 the AQCC directed the PCTF to develop recommendations on the use of zero-bleed pneumatic devices for rulemaking in 2020. Because the PCTF was unable to reach consensus on a recommendation, we believe the AQCC should direct the Division to continue its research and develop a proposal for the planned December 2020 rulemaking. Specifically, the Division should continue to research and put forth recommendations based on the information provided below by Earthjustice and CATF. No-bleed and self-contained PCs are a proven technology that should be implemented in Colorado. Furthermore, the successful implementation of solar-powered PCs in Canada points to the need for serious consideration of this technology in Colorado.

7.3.1 <u>Current applications</u>

As discussed above in Section 5.3, most of the no-bleed PCs in use in Colorado are in the DJ basin NAA and at newer multi-horizontal well pad facilities producing significant volumes of oil and gas. The PC field study also demonstrates that the majority of compressor stations in the NAA are currently operating or under construction to operate on instrument air.

<u>Industry Position:</u>

No-bleed controllers can generally be utilized on any piece of equipment that utilizes a natural gas actuated PC, but as detailed below, technical feasibility, safety concerns, other regulatory requirements, contractual obligations, and cost can all limit the ability of an owner or operator to utilize no-bleed PCs on some or all pieces of equipment at a facility.

Solar-powered PCs have recently been utilized in Alberta, Canada under specific operating conditions for where they are included in the design for a separator equipment package. However, industry believes that the array of solar batteries and battery storage has not yet been fully demonstrated to be sufficient and reliable for the power demands of well pads with multiple horizontal wells that produce significant volumes of oil and gas. As technology advances and costs decrease, the use of solar panels and battery storage to provide electrical power at large oil and gas production facilities may become feasible.

Industry is currently working on a regulatory proposal regarding the use of no-bleed PCs to be considered for a future AQCC rulemaking. This regulatory proposal will build on the work developed for a no-bleed PC emission mitigation strategy proposed under the SHER stakeholder process.

<u>CATF/EJ Position:</u>

Regulations currently in force in Alberta and British Columbia (BC) will significantly limit the use of venting gas-driven PCs moving forward. In BC, new facilities cannot use venting gas-driven PCs after January 1, 2021. Large compressor stations will require retrofit of all venting gas-driven PCs by January 1, 2022.[11] In Alberta, no new gas-driven venting PCs can be installed after January 1, 2022 (this regulation was very recently tightened – previously operators were to be allowed to use gas-driven venting controllers for up to 10% of new controllers after January 1, 2022).[12] Both provinces also will subject existing PCs, including intermittent PCs, to various emission limits.

Solar-powered PCs have been utilized for a number of years in Alberta where they are included in the design for separator equipment packages from certain manufacturers. Other operators have utilized similar solar-powered systems in custom configurations (for example to provide more electrical power and storage than is available in standard packages). Solar systems are used on both low-production wellsites and modern, high-production tight/shale wells.

This technology has proven reliable in Alberta north of 55°N latitude, where sunlight on a clear winter day is far weaker than in Colorado, snowfall is higher, winter cloud cover is much more common, and winter temperatures are much lower (affecting battery capacity). In short, CATF and EJ believe that there is no reason that this technology cannot succeed in Colorado.

[11] See BC Regulation 282/2010, §52.05.
http://www.bclaws.ca/civix/document/id/regulationbulletin/regulationbulletin/Reg286_2018

[12] See Alberta Energy Regulator (2020), "Directive 060 - Upstream Petroleum Industry Flaring, Incinerating, and Venting," §8.6.1. https://www.aer.ca/documents/directives/Directive060_2020.pdf

As noted above, there are also air compression systems designed for solar-powered sites on the market.

7.3.2 Effectiveness of devices

Industry Position:

Industry believes that the effectiveness of a no-bleed or self-contained PC is highly dependent on the application of the controller. The scope of the PCTF study did not evaluate the effectiveness of no-bleed PCs so no conclusions can be offered in this report. The consideration of the use of no-bleed PCs is being addressed under a SHER work group regulatory proposal as directed by SB 19-181.

CATF/EJ Position:

CAFT and EJ believe that previous work has documented the general applicability and reliability of solar-powered electric controllers;[13] this approach will be one of the key technologies allowing operators in Alberta and BC to comply with the provincial rules mentioned above.

7.3.3 Costs for new and retrofit facilities

Industry Position:

Based on operator survey results, the cost of instrument air systems (no-bleed pneumatic controllers) is highly variable and significantly higher for retrofits versus new installations.
The cost of self-contained PCs was not able to be ascertained through this study. However, industry has estimated that the cost to design the large and intricate vapor recovery system to capture these small emissions is significant and not cost-effective in most cases.

Likewise, industry estimates that the cost of routing controllers to a combustion device is prohibitively expensive unless the controller is located in close proximity to the control device (e.g. on the inlet to the control device itself).

Mechanical controllers, which can only be used for liquid level control in specific applications, were reported to have low capital costs, but higher maintenance costs than PCs based on operator survey results. Electric controllers were reported to cost significantly more, and also have higher maintenance costs, than PCs.

CATF/EJ Position:

The Conservation Groups' pneumatics proposal from the 2017 oil and gas rulemaking (which was also included as a SHER team proposal) was supported by an Economic Impact Assessment (EIA) documenting the cost-effectiveness of using zero-emitting approaches instead of gas-driven venting controllers. All cost calculations included in the Conservation Group's 2017 EIA include full costs for solar-powered electric systems, including: solar panels, batteries, and control panels and electronics; over-

[13] See Carbon Limits (2016), *Zero emission technologies for pneumatic controllers in the USA: Applicability and cost effectiveness.* https://www.catf.us/wp-content/uploads/2019/09/CL2016-ZeroEmitting-Pneumatics-Alts-1Aug2016.pdf

capacity for solar panels and batteries to ensure power will be available during (for example) extended cloudy periods in winter; electric actuators; installation; and maintenance. Operators report lower maintenance costs with electric systems than gas-driven systems when only wet gas is available to operate PCs, due to deleterious effects of wet gas on some PC components.[14]

In the 2017 rulemaking and as part of the SHER team, the Conservation Groups made available spreadsheets listing parameters for calculating cost-effectiveness, such as cost estimates for various components and labor, and engineering design assumptions such as the appropriate oversizing of solar panels and maximum allowable discharge from batteries.

7.3.4 Limitations and Barriers to expanded use

Industry Position:

In addition to cost, industry believes that there are technical, safety, regulatory, and land/leasehold concerns that limit the use of no-bleed and self-contained pneumatic controllers.

In terms of instrument air systems, operators must have sufficient grid or other power to run the instrument air skid and associated equipment. Further, some facilities will not have sufficient area at the facility to install the instrument air skid and associated infrastructure or may have landowner or regulatory restrictions on the grid power right of way or installation of additional equipment at the facility. Additionally, even where some controllers can be converted to instrument air there may be some processes that need to be controlled with natural gas-driven PCs for safety or technical reasons.

The biggest limitations to utilizing self-contained PCs or routing the vent port of the controller to a control device, aside from cost, are related to pressures. If there is not a process that is operating at a relatively low pressure then the pressure released from the vent port will not be sufficient to push the gas into the process line, potentially creating a safety hazard if a safety valve is not able to actuate against the process pressure. Additionally, beyond the cost of the amount of tubing that is required the route emissions from controllers that are located throughout a facility to a process line or control device, the longer that tubing is the more pressure differential (higher than the process or control device backpressure) is required to overcome the backpressure created by the tubing itself.

As mentioned previously, industry claims that mechanical and electric controllers can only be used to control liquid level and can only be used in certain applications (such as liquid level control). Additionally, mechanical controllers have been shown to be less accurate than PCs and electric controllers cannot typically be located on compressors due to vibration and require more technical knowledge to ensure safe application.

CATF/EJ Position:

[14] See Carbon Limits (2016) at p. 15.

As noted above, air compressors designed for solar-powered sites are on the market, as are packages systems that provide compressed air using hybrid electrical systems utilizing solar and batteries for the majority of the power they consume, with a gas-fired generator available as backup for the solar generation and battery. CATF and EJ believe that previous work has documented the general applicability and reliability of solar-powered electric controllers.[15]

7.3.5 Opportunities for expanded use

Industry Position:

Given the current state of technology, the use of electric and mechanical controllers is limited due to the limitation outlined in the section above. Industry believes that electric and mechanical controllers have very limited applications and cannot be used in the place of all traditional PCs at a facility. While there are extensive barriers that exist for retro-fitting existing facilities with instrument air, opportunity exists to expand the use of instrument air at new larger horizontal facilities that have sufficient grid power. Many of the land use and spacing limitations can be avoided if these systems are included during the planning phase. Additionally, there is a lower cost associated with installing a new system compared to retrofitting a location.

The ability to be able to plan for and allow utilities to commit to providing access to electrical grid power with sufficient power in advance of constructing new oil and gas production facilities represents a significant opportunity to expand the use of no-bleed PCs.

CATF/EJ Position:

CATF and EJ believe that zero-emitting technology can cost-effectively reduce emissions in Colorado at both new and existing sites. The CATF and EJ recommend that the AQCC consider requiring operators to utilize zero emitting pneumatic controllers statewide at all natural gas compressor stations and all well production facilities with four or more wells producing hydrocarbons so long as it is technically feasible to do so. CATF and EJ have previously offered this proposal in the 2017 oil and gas rulemaking and through the SHER team process. CATF and EJ believe that it is supported by the EIA and supporting spreadsheets, as well as the documented use of zero-emitting technology in Canada and the fact that venting PCs are being phased out for new facilities in British Columbia and Alberta.

8 Acknowledgments

The Division would like to thank all of the members of the PCTF for all of their time and hard work over the last two and a half years. The input from all stakeholders was vital to develop and implement what was the largest study of PCs to date. The information contained in this report is the culmination of thousands of hours of effort. The Division would also like to recognize the high level of engagement, collaboration, and resource expenditure from the industry members on the PCTF.

[15] Carbon Limits (2016).

ATTACHMENT A

Pneumatic Controller (PC) Task Force Data Collection Form

General Information

Inspector

Pad/Battery/Facility/Location

Blinded ID

Date

Time

Ambient Temperature

Wind Speed (MPH)

Inventory Information

Manufacturer*

Other:

Family (If Applicable)

Model*

Other:

Sensed Variable*

Other:

Type*

Other:

Supply Pressure (If Available) & Source

(psig) Enter 'None' if no gauge

Source:

Other:

Function*

Vent Type*

Vent Control Type*

Equipment Location*

Other:

Service Type*

Name/Description

Is PC Enclosed?*

Enclosure Type, If Not Exposed to Elements*

Additional Notes:

Inspection Information

Operating Properly*

Actuation Observed*

Detection Method*

Emissions Location*

Other:

If not operating properly provide the following:

Indicator 1

Indicator 2

Other:

Additional Notes:

Repair Information

Primary Cause of Improper Operation*

Other:

Repair Date

PC Repair Method*

Other:

Did the Repair Require:*

Double block and bleed

Shutdown and purge equip. to atmosphere

Shutdown of the well

Repair Time (Mins)

Repair travel time (if required)

Additional Notes:

Re-inspection Date

PC Repair Re-inspection Method*

CAA Ex. 8

An asterik (*) indicates that a field has a dropdown list

ATTACHMENT B

INSTRUCTIONS FOR COMPLETING THE DATA COLLECTION FORM FOR APCD PNEUMATIC CONTROLLER STUDY

MAY 9, 2018

These instructions serve to assist operators participating in the APCD's Pneumatic Controller (PC) Study specific to selected oil and gas facilities in the Front Range/Denver Metro Area Ozone Nonattainment Area (NAA) in the collection of data related to whether PCs in service at these facilities are operating properly.

It is important the persons conducting these inspections understand the focus of this study is limited to assessing the proper operation of PCs that are actuated using pressurized natural gas as a motive force and have the ability to vent to the atmosphere during normal operation. Leaks found to be originating from a component are not considered to represent improper operation of a PC. Instead, these observations should be considered leaks of components subject to a Leak Detection and Repair Program (LDAR).

Operators conducting these inspections of PCs at facilities selected for the purposes of this study will utilize concurrently an Audio, Visual and Olfactory (AVO) method along with an Approved Instrument Monitoring Method (AIMM) for each PC being inspected. Although other potential methods may be used to detect whether a PC is operating properly or not, these methods are not utilized by participating operators with facilities in the NAA and therefore will not be considered in the scope for Phase 1 of this study. Persons conducting these inspections of PCs for this study should strive to identify and document insights that were gained in applying methods in the field to determine whether a PC is properly operating or not. Although this form serves a purpose to document a specific inspection of a PC, the real value will be in being able to accurately describe what was done, observed or evaluated to determine if a PC was operating properly, along with any repairs necessary to a PC that was not operating properly.

<u>General Instructions</u>

- This form is to be used by an operator in conducting an inspection at a facility selected for the PC Study to document whether a PC is properly operating or not. As an option, the inspection data can also be captured using a flat table.
- If an inspector uses the form for data entry, one form is to be completed by the operator for each PC inspected at a facility. If the inspector uses the flat table rather than the form for data entry, one row in the table is to be completed for each PC inspected at a facility.
- PCs are not considered to be in service if the supply gas is depressurized; therefore, these out of service PCs are not to be inventoried or inspected for this study.
- For a PC that is found to be operating properly, the form or table row must be completed through the Inspection Information section.
- For PC that is found to be operating improperly, the entire form or table row must be completed including the Repair Information section. Neither the repair nor the Repair Information section must be completed at the time of the inspection. If the repair is not successfully completed at the time of the inspection, the details of the successful repair must be added to the form or flat table once completed.

- The confirmation of successful repair does not need to be completed at the time of the repair. The details of the repair confirmation must be added to the form or flat table once completed.
- The data collection form is provided in an Excel format tied to a flat table that can be used to compile the data for each PC inspected at a facility. Although the use of the electronic version of this form is encouraged, a hard copy of the form can be used in the field if the dropdown options are used appropriately and consistently with those in the electronic form. However, this will require that the data in the hard copy of the form be re-entered into the Excel form or flat table so that the data can be compiled for subsequent reporting.

Specific Instructions

- The specific instructions herein address the completion of individual subject fields in the data collection form or flat table.
- An asterisk symbol (*) next to the data field indicates that a dropdown menu of options exists for this specific field. To open the dropdown menu, click on the data field until the down arrow symbol is highlighted to the right of the data field and then click on this symbol. Select by clicking the option that correctly describes the characteristic specific to the PC inspected. Only one option can be selected for each data field with a dropdown menu.
- The "Other" option for a specific data field is to be used when none of the options in the dropdown menu applies to the PC. When none of the specific dropdown options apply, select the "other" option from the dropdown menu and enter as text the information in the separate "Other" data field.
- Use the additional notes data field provided in each section of the form to add free form text describing noteworthy information relevant to the inventory, inspection, or repair sections.

General Information Section

Inspector – Enter the first and last name of the person performing the inspection of the PC.

Pad/Battery/Facility/Location – Enter the operator's designated name of the facility.

Facility ID – Enter the blinded ID designated by Spirit Env. for the facility being inspected. Each operator will be provided a list of facilities randomly selected for inspection by Spirit Env. and each facility selected will have a Blinded ID.

Date – Enter the date when the inspection of the PC was conducted using the numerical month/day/year format (xx/xx/xxxx).

Time – Enter the approximate time that the inspection of the PC started in a numerical format (xx:xx) with an AM or PM designation.

Ambient Temperature - Enter the approximate temperature at the time that the inspection started in Fahrenheit degrees.

Wind Speed - Enter the approximate wind speed at the time that the inspection started in miles per hour.

Inventory Information Section

Manufacturer* – Select the manufacturer of the PC if known. The dropdown options represent PC manufacturers that are believed to be common in the DJ Basin, yet may not cover all makes. If not listed, select "Other" as a dropdown option and enter the full manufacturer name using text in the separate "Other" data field. If the manufacturer is unknown or not certain, take a photograph of the PC and later attempt to confirm the manufacturer of the PC using available information.

Family – This data field is to be completed, as applicable, if the manufacturer of the PC uses a family classification to describe its line of PCs. If no family classification exists, leave this data field blank.

Model* – Select the model of the PC if known. The dropdown options represent PC models that are believed to be common in the DJ Basin, yet may not cover all models. If not listed, select "Other" as a dropdown option and enter the model as text in the separate "Other" data field. If the model is unknown or not certain, take a photograph of the PC and later attempt to confirm the model of the PC using available information. Please be careful in selecting the correct model as some model designations may vary slightly in their labeling.

Sensed Variable* – This data field describes the process variable that the PC is controlling. Dropdown options include pressure, temperature, position, differential pressure, and level. If the process variable is not listed, select "Other" as a dropdown option and describe the variable using text in the separate "Other" data field.

Type* – This data field distinguishes the type of PC being inspected in terms of its configuration. Only three options exist: integrated, pilot or other. An integrated PC refers to a PC that has both the sensing and actuating components contained in one housing. A pilot PC describes a PC that senses a signal and remotely actuates a device that is not contained in the same housing. If the type is not listed, select "Other" as a dropdown option and describe the type by entering text in the separate "Other" data field.

Supply Pressure & Source

- This data field records the pressure of the natural gas being applied as a motive force to the PC being inspected. If a pressure gauge exists on the supply line to the PC being inspected, record the pressure reading of the gauge. If no pressure gauge is present, then enter "None" in this data field. Do not enter "zero" or "0" instead of "None" as this suggests that there is zero pressure, or the gauge is broken.
- The data field for "Source" refers to where the source of the natural gas as a motive force originates from and the dropdown options include wellhead, separator, pipeline quality or "Other". To confirm the source of the gas, the supply tubing to the PC being inspected may have to be followed to its point of origin. If the source of the natural gas is not listed, select "Other" as a dropdown option and describe the source using text in the separate "Other" data field.

Primary Function* – This data field describes the primary function that the PC being inspected. Only two options apply to this data field: process control or safety. An "Other" option is not available. The safety option should be selected where the PC is used to isolate a pressure source or cease operation of a process.

Vent Type* – This data field describes how the PC being inspected vents during an actuation cycle. Three dropdown options are available: a continuous high bleed (> 6scf/hr); a continuous low bleed (< 6 scf/hr); and an intermittent bleed. An "Other" option is not available. To determine the correct vent type, the operators should research the vent type classified by the manufacturer for the model of the PC being inspected. Measurement of the actual vent rate is not required for this study.

Vent Control Type* – This data field describes whether the vent from the PC being inspected is captured and routed. Three dropdown options are available: vented to atmosphere; captured and routed to sales or process; or captured and routed to a flare/combustor header. An "Other" option is not available. To determine the correct option, the operator may need to follow the vent tubing to the point where it connects to piping and determine whether the piping connects to a process or sales line, or a flare/combustion device.

Equipment Location* – This data field describes the equipment associated with the PC being inspected in terms of its purpose to control the equipment's operation. Available dropdown options include: wellhead, separator, heater, combustor, compressor engine, generator, dehydrator (dehydration unit), and other. If the type of equipment is not listed, select "Other" as a dropdown option and enter the type of equipment using text in the separate "Other" data field.

Service Type* – This data field describes the service of the PC being inspected in terms of how the process variable is controlled. The dropdown options are: on/off, throttling, or unknown. An "Other" option is not available. If the inspector is unsure of whether a PC is on/off or throttling, the inspector should select unknown.

Name/Description – This data field provides a more specific description of the piece of equipment so that the PC being inspected can be identified and located, especially at facilities where there is more than one of the same equipment type (i.e. heater treater 4, water dump). No dropdown menu is available.

Is PC Enclosed? – This data field provides a yes or no answer to whether the PC is located within some type of enclosure that shields the PC from the elements such as a hinged case, a cabinet, or building. Answer "No" if no enclosure exists around the PC being inspected.

Enclosure Type (If Not Exposed to Elements) – This data field is to be completed only if the PC is enclosed as indicated by a "Yes" response to the previous data field. Three dropdown options exist for a "Yes" response: inside separator cabinet, inside compressor enclosure, or inside other enclosure? An "Other" option is not available.

Additional Notes – This data field is a text box that allows additional information to be provided that are worth noting to describe conditions specific to the facility, equipment or PC being inspected.

Inspection Information Section

Operating Properly – This data field identifies whether the PC being inspected is operating properly. Two dropdown options exist: Yes or No. An "Other" option is not available. If the "Yes" option is selected because the PC is found to be operating properly, ~~then~~ then do not complete the Detection Method data field below ~~must be completed~~. If the "No" option is selected because the PC is found to not be operating properly, then ~~do not~~ complete the Detection Method data field below.

Actuation Observed – This data field identifies whether the PC being inspected was observed to actuate during the inspection. Three dropdown options exist: Yes, No or Unknown. An "Other" option is not available.

Detection Method – This data field identifies the method used to detect whether a PC is not operating properly ~~or not~~. This data field must be completed only if the "No~~Yes~~" option is selected for the "Operating Properly" data field above. Three dropdown options exist: Audio-Visual-Olfactory (AVO) Only, Approved Instrument Monitoring Method (AIMM) Only, and AVO/AIMM. An "Other" option is not available.

- AVO refers to hearing, seeing or smelling something that indicates a PC is not operating properly. Indicators associated with hearing may include hissing or clicking. Detection of a hydrocarbon odor near a PC may not be telltale yet could still indicate a process is not being controlled properly due to an improper operation of a PC. AVO to be selected as a dropdown option when this method was able to independently determine that a PC was not operating properly.
- AIMM refers to methods approved for use by APCD under Reg 7 such as an optical gas imaging (OGI) camera. For the purposes of this PC study for the NAA, an OGI camera will be the only AIMM used. AIMM is to be selected as a dropdown option when this method was able to identify that a PC was not operating properly and AVO was not able to independently make this determination.
- AVO/AIMM is to be selected as a dropdown option when both methods in concert were required to detect that a PC was not operating properly.

Emissions Location – This data field identifies where emissions are detected from a PC being inspected that is not operating properly. Three dropdown options exist: Vent Port, Body or "Other". If the emission location is other than the Vent Port of Body, then select "Other" as a dropdown option and enter a description using text in the separate "Other" data field. Emissions from supply tubing connections or other components do not represent improper operation of a PC.

Indication of Proper Operation – This data field describes what indicator(s) were found that led to a determination that the PC being inspected was not operating properly. Two data fields with dropdown menus with options are provided including an "Other" option. If the indicator is not listed in the dropdown menu, then select "Other" as a dropdown option and enter a description using text in the separate "Other" data field. If there are more than two indicators, use the Other field to enter text describe any additional indicators.

Additional Notes – This data field is a text box that allows additional information worth noting specific to the PC being inspected. These notes can be used to provide further insight into what was done, observed or evaluated during the inspection to determine whether the PC was operating properly or not.

Repair Information Section

Primary Cause of Improper Operation – This data field identifies the primary cause of improper operation of the PC being inspected. Ten dropdown options are provided including an "Other" option. Select the option that is believed to be the primary cause. If the primary cause is not listed in the dropdown menu, then select "Other" as an option and enter a description using text in the separate "Other" data field.

Repair Date - Enter the date when the repair of the PC that was found to be operating improperly was successfully completed using the numerical month/day/year format (xx/xx/xxxx).

PC Repair Method – This data field identifies the method(s) applied to repair the PC that was inspected and found to be operating improperly. Eleven dropdown options are provided including an "Other" option. Select the option that best represents the repair method necessary to return the PC to proper operation. If the repair method applied is not listed in the dropdown menu, then select "Other" as an option and enter a description using text in the separate "Other" data field.

Did the Repair Require a double block and bleed? Shutdown and purge equipment to atmosphere? Shutdown of the well? - These data fields describe whether any of the listed actions were necessary to make the repair of the PC that was found to be operating improperly. A Yes or No response is needed for each of the three actions listed. An "Other" option is not available.

PC Repair Confirmation Method – This data field identifies the method used to confirm that the PC repair was successful to restore the PC to proper operation. Five dropdown options exist: AIMM, AVO, Soapy Water, Method 21, and Physical Inspection. Select the method used to confirm a successful repair. An "Other" option is not available.

Repair Time Onsite – This data field documents the amount of time needed once onsite to complete the successful repair of a PC found to be operating improperly. Enter the amount of time in hours using 15-minute increments (i.e. 0.25, 0.5, 0.75, 1.0, 1.25, 1.50, etc.). Repair Travel Time (if required) – This data field documents the travel time needed to visit the facility to make a necessary repair of a PC found to be improperly operating. This travel time information is only required if a separate trip is needed to make the repair separate from the trip made to conduct the inspection for this study. Enter the amount of time in hours using 15-minute increments (i.e. 0.25, 0.5, 0.75, 1.0, 1.25, 1.50, etc.)

Re-Inspection Date – Enter the date when re-inspection of a PC that was subject to repair was completed to confirm its proper operation using the numerical month/day/year format (xx/xx/xxxx).

PC Repair Re-Inspection Method – This data field identifies the method used to re-inspect a PC that was subject to repair. Three dropdown options are provided – AIMM, AVO or soapy water. Select the method used to confirm the successful repair. An "Other" option is not available.

Additional Notes - This data field is a text box that allows additional information worth noting specific to the PC being repaired and re-inspected. These notes can be used to provide further insight into what was done, observed or evaluated to successfully complete the repair and confirm the repair during the re-inspection to demonstrate that the PC was returned to proper operation.

PLEASE CHECK THAT THE FORM IS COMPLETE AFTER EACH INSPECTION AND IF A REPAIR IS REQUIRED.