<u>Proposed 20.2.50 NMAC: Oil and Gas Sector – Ozone Precursor Pollutants</u>
<u>The GCA's Proposed Amendments to 20.2.50.113.B(2) and 20.2.50.113.B(3) NMAC</u>

The GCA's Proposed Amendments to 20.2.50.113.B(2), Table 1, NMAC:

20.2.50.113 ENGINES AND TURBINES

B. Emission standards:

(2) The owner or operator of a portable or stationary 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:

* * *

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

Engine Type	Rated bhp	NOx	CO	NMNEHC (as propane)
Lean-burn	> 1,000	~~0.50~~<u>2.0</u> 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

The GCA's Proposed Amendments to 20.2.50.113.B(3), Table 2, NMAC:

20.2.50.113 ENGINES AND TURBINES

B. Emission standards:

(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 <u> MANUFACTURED OR </u>~~CONSTRUCTED, ~~RECONSTRUCTED~~, OR INSTALLED~~ AFTER THE EFFECTIVE DATE OF 20.2.50 NMAC.

Engine Type	Rated bhp	NOx	CO	NMNEHC (as propane)
Lean-burn	>500 - <~~1000~~<u>1,875</u>	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

Lean-burn	≥ ~~1000~~1,875	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

NOTE: The suggestion to use 1,875 rated bhp as the size cutoff to determine the applicable NOx emission standards for lean-burn engines is contingent on the applicability of the Table 2 engine emission standards being changed to use the date of manufacture or reconstruction of the engine (in place of the date of construction, reconstruction, or installation). If the applicability of the Table 2 engine emission standards is based on the date of construction, reconstruction, or installation, Table 2 should be changed to use 2,500 as the rated bhp as the size cutoff to determine the applicable NOx emission standards for lean-burn engines.

Proposed 20.2.50 NMAC: Oil and Gas Sector – Ozone Precursor Pollutants
The GCA's Proposed Amendments to 20.2.50.113.C(1) NMAC

The GCA's Proposed Amendments to 20.2.50.113.C(1) NMAC:

20.2.50.113 ENGINES AND TURBINES:

C. **Monitoring requirements:**

(1) Maintenance and repair for a spark-ignition engine, compression-ignition engine, and stationary combustion turbine shall ~~meet~~ be consistent with the minimum manufacturer recommended maintenance schedule or a schedule developed by the owner or operator that must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. 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.

Proposed 20.2.50 NMAC: Oil and Gas Sector – Ozone Precursor Pollutants
The GCA's Proposed Amendments to 20.2.50.7; 20.2.50.122.B(3), Tables 1 & 2; 20.2.50.122.B(4); and 20.2.50.122.C(1) & (4)

The GCA's Proposed Amendments to 20.2.50.7 NMAC:

20.2.50.7 DEFINITIONS:

"Intermittent pneumatic controller" means a pneumatic controller that is not designed to have a continuous bleed rate, but is designed to only release natural gas to the atmosphere as part of the actuation cycle.

The GCA's Proposed Amendments to 20.2.50.122.B(3), Tables 1 & 2; 20.2.50.122.B(4); and 20.2.50.122.C(1) & (4) NMAC:

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 shall comply with the requirements of 20.2.50.122 NMAC according to the following schedule:

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

Total Historic Percentage of Non-Emitting Controllers or Intermittent Pneumatic Controllers	Total Required Percentage of Non-Emitting Controllers or Intermittent Pneumatic Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers or Intermittent Pneumatic Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers or Intermittent Pneumatic 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 or Intermittent Pneumatic Controllers	Total Required Percentage of Non-Emitting Controllers or Intermittent Pneumatic Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers or Intermittent Pneumatic Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers or Intermittent Pneumatic 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) Standards for natural gas-driven pneumatic controllers.

(a) new pneumatic controllers shall have an emission rate of zero where on-site electrical grid power is being used and use of a no-bleed pneumatic controller is technically and economically feasible. Where on-site electrical grid power is not being used or the use of a no-bleed pneumatic controller is not technically or economically feasible, new pneumatic controllers must be intermittent pneumatic controllers.

(b) existing pneumatic controllers ~~with access to commercial line electrical power~~ where on-site electrical grid power is being used and use of a no-bleed pneumatic controller is technically and economically feasible shall have an emission rate of zero.

(c) existing pneumatic controllers shall meet the required percentage of non-emitting controllers or intermittent pneumatic controllers within the deadlines in tables 1 and 2 of Paragraph (3) 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, intermittent pneumatic controllers, and all non-emitting pneumatic controllers, except that pneumatic controllers 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 controllers or intermittent pneumatic controllers and sum the total number of non-emitting or intermittent pneumatic controllers and designate those as total historic non-emitting or intermittent pneumatic controllers.

(iii) determine the total historic non-emitting and intermittent pneumatic controller percent of controllers by dividing the total historic non-emitting and intermittent pneumatic 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 tables 1 and 2 of Paragraph (3) 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 or intermittent pneumatic 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.

*** * ***

C. Monitoring requirements:

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

* * *

(3) The owner or operator of a pneumatic controller that is subject to the monitoring requirements in Subsection C of 20.2.5.122 NMAC ~~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 EMT shall be linked to~~ The owner or operator of a pneumatic controller shall maintain 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) if continuous, design annual bleed in standard cubic feet per year.

D. Recordkeeping requirements:

(5) The owner or operator shall maintain an electronic record for each pneumatic controller that is subject to the monitoring requirements in Subsection C of 20.2.5.122 NMAC ~~with a natural gas bleed rate greater than zero~~. The record shall include the following:

Proposed 20.2.50 NMAC: Oil and Gas Sector – Ozone Precursor Pollutants
The GCA's Proposed Amendments to 20.2.50.115.B(4) and 20.2.50.113.C(2) NMAC

The GCA's Proposed Amendments to 20.2.50.115.B(4) NMAC:

20.2.50.115 CONTROL DEVICES:

B. General Requirements:

(4) The owner or operator shall inspect control devices used to comply with this Part ~~at least monthly~~ to ensure proper maintenance and operation at least monthly or on a schedule developed by the owner or operator that must provide to the extent practicable for the maintenance and operation of the control device in a manner consistent with good air pollution control practice for minimizing emissions, unless a different schedule is specified in the Section applicable to that control device. 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.

The GCA's Proposed Amendments to 20.2.50.113.C(2) NMAC:

20.2.50.113 ENGINES AND TURBINES:

C. Monitoring requirements:

(2) Catalytic converters (oxidative, selective, and non-selective) and AFR controllers shall be inspected and 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.

Proposed 20.2.50 NMAC: Oil and Gas Sector – Ozone Precursor Pollutants
The GCA's Proposed Amendments to 20.2.50.112.B(2) NMAC

The GCA's Proposed Amendments to 20.2.50.112.B(2) NMAC:

20.2.50.112 GENERAL PROVISIONS:

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 within a reasonable time not more than 90 days after receipt of the request. 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.

Proposed 20.2.50 NMAC: Oil and Gas Sector – Ozone Precursor Pollutants
The GCA's Proposed Amendments to 20.2.50.113.C(3) NMAC

The GCA's Proposed Amendments to 20.2.50.113.C(3) NMAC:

20.2.50.113 ENGINES AND TURBINES

C. Monitoring requirements:

(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 NOx, 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:

* * *

(i) For emissions tests using a portable analyzer, the results of emissions testing demonstrating compliance with the emissions standards for CO may be used as a surrogate to demonstrate compliance with the emissions standards for NMNEHC.

<u>Proposed 20.2.50 NMAC: Oil and Gas Sector – Ozone Precursor Pollutants</u>
<u>The GCA's Proposed Amendments to 20.2.50.116.C(1)(e) NMAC</u>

The GCA's Proposed Amendments to 20.2.50.116.C(1)(e) NMAC:

20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS

C. Default Monitoring Requirements:

(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~~ <u>business</u> days

Proposed 20.2.50 NMAC: Oil and Gas Sector – Ozone Precursor Pollutants

The GCA's Proposed Amendments to 20.2.50.112; 20.2.50.113.B(9), C(7) and D(1) & (2); 20.2.50.114.B(5); 20.2.50.115.B(3) & (4), C(2)(d), D(2)(c) and E(2)(b); 20.2.50.117.B(4) and C(3); 20.2.50.118.B(3)(d); 20.2.50.119.B(4) and C(4); 20.2.50.122.B(6), C(4) and D(6) & (7); 20.2.50.123.B(8) and C(4); and 20.2.50.123.B(8) and C(4) NMAC

The GCA's Proposed Amendments to 20.2.50.112 NMAC:

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 NOx.

~~(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 NOx, if applicable) PTE in lbs./hr. and tpy;~~

~~(e) for a control device, the controlled VOC and NOx 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 emission standards and monitoring under~~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 within a reasonable time not more than 90 days after receipt of the request. 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 three business days~~24 hours~~ of a request by the department, the owner or operator shall for each unit subject to the request, provide the requested information to the department.~~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.~~

The GCA's Proposed Amendments to 20.2.50.113.B(9), C(7) and D(1) & (2) NMAC:

20.2.50.113 ENGINES AND TURBINES

B. Emission standards:

~~(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.~~

C. Monitoring requirements:

(7) ~~Prior to monitoring, testing, inspection, or maintenance of an engine or turbine, the owner or operator shall scan the EMT, and the~~ The monitoring data ~~entry~~

shall be ~~made~~ electronically captured 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;

(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;

The GCA's Proposed Amendments to 20.2.50.114.B(5) NMAC:

20.2.50.114 COMPRESSOR SEALS

B. Emission standards:

~~(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.~~

The GCA's Proposed Amendments to 20.2.50.115.B(3) & (4), C(2)(d), D(2)(c) and E(2)(b) NMAC:

20.2.50.115 CONTROL DEVICES

B. General requirements:

~~(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~~The required monitoring data shall be electronically captured in accordance with this Part.

C. Requirements for open flares:

(2) Monitoring requirements:

(d) ~~prior to an inspection or monitoring event, the EMT on the flare shall be 19 scanned and the~~ The required monitoring data shall be electronically captured during the event in accordance with the monitoring requirements of 20.2.50.112 NMAC; and

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

(2) Monitoring requirements:

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

E. Requirements for vapor recovery units (VRU):

(2) Monitoring Requirements:

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

The GCA's Proposed Amendments to 20.2.50.117.B(4) and C(3) NMAC:

20.2.50.117 NATURAL GAS WELL LIQUID UNLOADING

B. Emission standards:

~~(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:

(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.

The GCA's Proposed Amendments to 20.2.50.118.B(3)(d) NMAC:

20.2.50.118 GLYCOL DEHYDRATORS

B. Emission standards:

~~(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.~~

The GCA's Proposed Amendments to 20.2.50.119.B(4) and C(4) NMAC:

20.2.50.119 HEATERS

B. Emission standards:

~~(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:

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

The GCA's Proposed Amendments to 20.2.50.122.B(6), C(4) and D(6) & (7) NMAC:

20.2.50.122 PNEUMATIC CONTROLLERS AND PUMPS

B. Emission standards:

~~(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:

(4) ~~The EMT shall be linked to~~ The owner or operator of a pneumatic controller shall maintain 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) if continuous, design annual bleed in standard cubic feet per year.

D. Recordkeeping requirements:

(6) The owner or operator of a natural gas-driven pneumatic controller with a bleed rate greater than six standard cubic feet per hour shall maintain a record ~~in the EMT database~~ of the pneumatic controller documenting why a bleed rate greater than six scf/hr 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:

The GCA's Proposed Amendments to 20.2.50.123.B(8) and C(4) NMAC:

20.2.50.123 STORAGE VESSELS
B. Emission standards:

~~(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.~~

C. Monitoring requirements:

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

STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF:

PROPOSED NEW REGULATION
20.2.50 Oil and Gas Sector — Ozone Precursor Pollutants **No. EIB 21-27(R)**

PRE-FILED TECHNICAL TESTIMONY OF MR. VIC L. SHELDON,
A WITNESS ON BEHALF OF THE GAS COMPRESSOR ASSOCIATION

I. Introduction to My Testimony

My name is Vic L. Sheldon. I am testifying as a technical witness on behalf of The Gas Compressor Association (The GCA) in this proceeding. My testimony supports The GCA's proposed amendments to the New Mexico Environment Department's (Department) proposed regulation set out as 20.2.50.113.B(3) NMAC in the Department's proposed rule, 20.2.50 NMAC (Proposed Rule), specifically the emissions standards for engines. The GCA's proposed amendments to the Department's Proposed Rule are set forth in redline in GCA Exhibit 1. This testimony begins with an overview of my credentials. I will then go on to discuss the Department's proposed engine emissions standards, as set forth in the Department's Proposed Rule at 20.2.50.113.B(3) NMAC and The GCA's proposed amendments thereto.

As set forth in detail herein, natural gas original equipment manufacturers (OEMs), upstream and midstream end-users acknowledge and support employing the Best Available Technology (BAT) for emissions control from their engines, controls, packages, and installations. Natural gas OEMs, upstream and midstream end-users support lower oxides of nitrogen as this aids reduction of precursor compounds which result in ozone formation. The Gas Compression Packaging OEMs and end-users employ BAT products in order to gather, process and transport natural gas. The Department's Proposed Rule at 20.2.50.113.B(3) NMAC applies a 0.3g NOx per bhp-hr rating to new lean-burn combustion engines above 1000 bhp. The NOx emission standard in the Proposed Rule is lower than achievable in some spark ignited natural gas lean-burn combustion engines at the 1000 bhp power level. Currently available lean-burn engines with power ratings of 1000 to 1875 bhp are rated "Not to Exceed" (NTE) 0.5g NOx/bhp-hr. NTE emissions rating means the engine will operate below and up to 0.5g NOx per bhp-hr, but are not capable of operating at and below 0.3g NOx per bhp-hr on a NTE basis. Therefore, as set forth in The GCA's proposed amendments to 20.2.50.113.B(3), the 1000 bhp power level provided in the regulation should be raised to 1875 bhp to reflect emissions the BAT provide in newly manufactured lean-burn engines.

My testimony provides an overview of today's BAT in some lean-burn spark-ignited natural gas engines above the 1000 bhp power level, which I will explain cannot achieve the 0.3g NOx per bhp-hr in the Proposed Rule. I will explain in detail why raising the power threshold from 1000 bhp to 1875 bhp for such engines is necessary to align with the Department's proposed definition of larger engines capable of employing pre-combustion chambers for effective combustion ignition of extremely lean fuel mixtures which can achieve the 0.3 g NOx per bhp-hr emissions. Larger lean-burn engines rated 1875 bhp and greater are currently rated NTE 0.3g NOx per bhp-hr.

I will also discuss how the emissions standards in Department's Proposed Rule at 20.2.50.113.B(3) NMAC will effectively eliminate certain large lean-burn engines from operating in New Mexico. It is not technically feasible to further apply Low Emissions Combustion (LEC) technologies to those engines – specifically, those lean-burn engines rated between 1000 and 1875 bhp. The available LEC technologies have already been applied to lean-burn engines presently on the market from engine manufacturers. Efficient, low-emitting engines of that size are essential for gas gathering operations in New Mexico, and the Department must avoid regulating them out of existence based on an attempt to apply a NOx emission standard that is technically infeasible.

Finally, I will testify regarding why the Department's proposed emissions limits are unnecessarily more stringent than the federal standards for large lean-burn engines.

II. Statement of My Qualifications and Relevant Experience.

My resume is attached as GCA Exhibit 10. I received a Bachelor of Science in Mechanical Engineering from Purdue University. I also hold a Masters of Business Administration from Indiana Wesleyan University. I am a registered Professional Engineer in the State of Illinois.

Caterpillar is the company I chose to work for in 1978 after resigning my Regular Army Commission. Over thirty-seven years of my career has been dedicated to engine engineering design, test and development, field validation, manufacturing, product support, education and training, marketing, and managing engine designers and developers. I first worked in development of Caterpillar Natural Gas Engines as a test and development engineer from 1985-1990, developing the first-known air/fuel ratio control specifically for rapidly changing fuel quality at a natural gas plant early in that time. I next worked as a manufacturing liaison engineer for natural gas engines in Lafayette, Indiana, for Gas Engine Engineering in Illinois from 1990-1992. I then worked as a Senior Product Quality Engineer and then as an Application and Design Engineer for gas engines.

In 2001, I became a Market Development Consultant working in Kiel and Rostock, Germany for Caterpillar Rail & Petroleum Power Products, working with gas engine products. In 2003, I started work at Caterpillar Oil & Gas Group, Marine & Petroleum Products Division, where I served as a Market Development Consultant, a Market Professional and a Senior Marketing Professional until 2013. From 2013 to 2015, I served as an Engineering Manager for Caterpillar

Inc.- Large Power Systems Development, developing customer-driven G3500 engine products. Caterpillar G3500 engines are one of the primary categories of engines that are subject to the Proposed Rule.

I am currently the General Manager of VSheldon JEvertt Decisions, LLC where I have been a member since 2016. My current responsibilities include assisting end-users, OEMs, and dealers of diesel and natural gas engine power systems to identify the right engine and related equipment for a particular use or application. I help my clients identify the appropriate engine for the job that they need to accomplish, and knowing how these engines operate, from an emissions performance and other perspectives, is a key part of my role. That experience has allowed me to serve as a testifying expert related to G3500 natural gas engines in other proceedings.

I have extensive experience in the marketing and development of electric and mechanical power employing natural gas and diesel engines. This includes initiating and managing the development of new product introduction programs, including emissions upgrade kits for stranded end-user G3516 gas compression engines that lowered those engines' 2g NOx per bhp-hr emissions to 0.5g NOx per bhp-hr. I also launched a New Product Introduction program to design, develop, and manufacture new G3500 gas compression engines for US EPA NSPS 2nd stage, reducing NOx emissions seventy-five percent, increasing power at altitude, improving fuel tolerance, and reducing fuel consumption. For over 30 years, I have been working on the design and optimization of the types of engines used by oil and gas operators and compression service providers that are subject to regulation under the Proposed Rule.

III. Brief Overview of Caterpillar Engines

As useful background and context for the Department's Proposed Rule for engine emissions standards, it is helpful to understand more about the types of engines that are subject to regulation under the Proposed Rule. In this respect, it is useful to learn more about Caterpillar engines, as Caterpillar engines have been chosen by many natural gas compression OEMs and end-users. Caterpillar represents the highest-volume of lean-burn spark-ignited natural gas engines chosen by gas compression packaging OEMs and natural gas gathering and processing companies in North America.

There are several reasons my presentation of spark-ignited natural gas lean-burn gas compression engines is focused on the Caterpillar branded engine products. First, Caterpillar has the broadest offering of spark-ignited natural gas compression engines in the industry. Within this offering is the broadest range of spark ignited lean-burn engines employed as gas compression drivers. For purposes of my testimony, when I refer to "lean-burn" engines, I am referring to engine combustion with excess air to greatly reduce the formation of oxides of nitrogen during combustion. When I refer to "rich-burn" engines, I am referring to engine combustion with the correct or stoichiometric mixture of fuel and air with no excess air, resulting in NOx formation of greater than 10 g per bhp-hr requiring non-selective catalytic reduction (NSCR) after-treatment to further reduce NOx.

The Department references Low Emissions Combustion (LEC) technology as retrofit technology and references an EPA Technical Support Document that states, "*LEC are described as retrofits that allow engines to operate on extremely lean fuel mixtures to minimize NOx emissions. (CSAPR TSD, p. 5-3).*" *See* GCA Exhibit 11 at p. 5-3. As described in greater detail below, the referenced document then identifies the different LEC technologies that are available. The Proposed Rule establishes a NOx emissions standard that cannot be met by certain sizes of new, lean-burn engines, despite the incorporation of the available LEC technology.

The technologies presented or identified as LEC retrofit options are already incorporated in today's Caterpillar lean-burn engines that are subject to the Department's proposed rule. A closer look at the various technologies Caterpillar lean-burn engines employ today will follow, but first a view of the general size comparisons of spark ignited lean-burn natural gas engines above 1000 bhp level may be assisted by reviewing Image 1, *Range of Caterpillar Power Options for Oil & Gas Applications*, presented as an attachment to my testimony.

Image 1 presents the range of Caterpillar power options employed by natural gas engine OEMs, and natural gas end-users in upstream gas gathering, in midstream gas processing plants, and in midstream pipeline transmission. Of the Caterpillar engine models shown, the G3500, G3600 and the GCM34 products are spark ignited lean-burn combustion engines, while the smaller G3300 and CG137 spark-ignited natural gas engine products are rich-burn combustion engines.

Engine bore size matters when integrating LEC technologies. The G3500J LE family of engines and the G3600 A4 LE family of engines are spark ignited lean-burn combustion engines developed to meet lower emissions standards than the federal New Source Performance Standards (NSPS). These engines have improved capabilities beyond their predecessors over a wide range of gas compression site conditions including altitude, fuel quality, and ambient temperature. The smaller G3500J LE engine driven gas compression packages typically gather gases from wells. The larger G3600 A4 LE engine driven packages then move gas from the gas gathering systems to the gas plants which remove natural gas liquids. Please note the smaller G3500J LE 0.5g NOx per bhp-hr engines and the larger G3600 A4 LE engines already incorporate LEC technologies for extremely lean mixtures. The following technologies already incorporated in these two engine families include redesigned cylinder-heads, pistons, camshafts, exhaust systems which deliver high temperature exhaust to improved larger more efficient turbochargers, two-stage intercooling, electronically controlled gas flow for precise combustion gas metering, electronically controlled air/fuel ratio controls, and electronic ignition delivering high energy voltage to spark plugs. These technologies for LEC referenced by Department as LEC technologies are in place on both engine families, with the exception of pre-combustion chambers. The much larger G3600A4 LE engine began its manufacture in 1991 with an integrated pre-combustion chamber. The much smaller bore diameter of the G3500J LE engines prevents integration of a pre-combustion chamber.

IV. The Department's Proposed Engine Emission Standards

The Department's Proposed Rule sets forth engines emissions standards for new natural gas-fired spark-ignition engines constructed, reconstructed, or installed after the effective date of the rule. *See* Proposed Rule at 20.2.50.113.B(3) NMAC. The rule sets forth emission limits by specifying engine type, the rated bhp, and then presents standards for NOx, CO and NMNEHC. *See* Proposed Rule20.2.50.113.B(3), Table 2, NMAC. As explained in detail below and for the reasons set forth herein, the Department's proposed 1000 bhp threshold for more-stringent NOx emissions standards from new lean-burn engines should be changed; the more-stringent NOx standards for new lean-burn engines should apply only to engines equal to or greater than 1875 bhp.

(i) The Proposed Engine Emission Standards Fail to Consider Existing BAT and LEC Technologies

Table 1 below, Engine Family NOx Capability Ratings and Cylinder Data, presents engine models with NOx emissions capability, rating, and various engine cylinder characteristics of the G3500J LE engine family & G3600 A4 LE engine family from 1000 to 2500 horsepower. Please note the G3500J LE lean-burn engine ratings provide a not to exceed (NTE) site 0.5g NOx per bhp-hr emissions capability, whereas the much larger bore diameter G3600 A4 LE lean-burn family of engines have two NTE site emissions capabilities: 0.3g NOx per bhp-hr and 0.5g NOx per bhp-hr. The much larger cylinder-bore area of the G3600 A4 LE engine is three times (3X) the cylinder-bore area of the G3500J LE engines. This lower 0.3g NOx per bhp-hr emissions rating is possible for the larger-bore G3600 A4 LE engines primarily because of the enhanced ignition characteristics provided by the pre-combustion chamber. The pre-combustion chamber produces multiple burning plasma jets into and across the extremely lean main combustion chamber. This enables the extremely lean mixture in the main cylinder to be leaner than an engine that does not have pre-combustion chamber ignition. Without the enhanced pre-combustion chamber ignition, the extremely lean mixture in the main cylinder would not reliably combust. The Department's Proposed Rule at 20.2.50.113.B(3) NMAC as currently drafted, with the threshold for 0.3gNOx per bhp-hr for new lean-burn spark ignited engines beginning at the 1000 bhp power level, needs to be adjusted upward to capture only "larger" engines 1875 bhp and above. This raised power level more accurately reflects the larger lean-burn engines' design capability to achieve BAT of 0.3g NOx per bhp-hr on a not to exceed (NTE) basis.

TABLE 1, Engine Family NOx Capability Ratings and per Cylinder Data

Engine Family NOx Capability Ratings and per Cylinder Data	Not To Exceed NOx/bhp-hr	Engine Rating bhp	Rating per Cylinder bhp	Cylinder Bore Area sq in	1 Cylinder Displacment cu. in	1 Cylinder Torque lb-ft
G3500J LE Engine Family	0.5 g NOx		86.25	35.3	264	324
G3512J LE	0.5 g NOx	1035	86.25	35.3	264	324
G3516J LE	0.5 g NOx	1380	86.25	35.3	264	324
G3520J LE	0.5 g NOx	1725	86.25	35.3	264	324
G3600 A4 LE Engine Family	0.3 & 0.5 g NOx		312.5	109.4	1290	1641
G3606 A4 LE	0.3 & 0.5 g NOx	1875	312.5	109.4	1290	1641
G3608 A4 LE	0.3 & 0.5 g NOx	2500	312.5	109.4	1290	1641

The Department's proposed regulation set forth at 20.2.50.113.B(3), Table 2, NMAC of 0.3g NOx per bhp-hr for 1000 bhp rated engines does not reflect the actual BAT or LEC technologies existing on the most commonly employed lean-burn engines in the 1000 bhp to 1725 bhp rating range that are available on the market today. Adoption of the 0.3 gper bhp-hr NOx standard for engines in the 1000-1875 bhp range would effectively eliminate this category of lean-burn engines for natural gas gathering in New Mexico to meet the Department's proposed NOx standard. Adjusting the power level threshold upward from 1000 bhp to engines beginning at 1875 bhp would reflect the existing BAT more appropriately of "larger" G3600 A4 LE lean-burn engines at 0.3g NOx/bhp-hr NTE emissions, and enables use of the BAT G3500J LE lean-burn engines at their NTE emissions rating of 0.5g NOx per bhp-hr. Pre-combustion chamber technology for the G3500J LE lean-burn compression application does not exist.

The Department's proposed NOx emission standard at 20.2.50.113.B(3) NMAC of 0.3g NOx per bhp-hr for engines rated at 1000 bhp or greater may inadvertently eliminate gas gathering powered by lean burn engine in these 1000 bhp to 1725 bhp power nodes. Use of oversized, larger natural gas engines attempting to operate at too low a load have significant operation and maintenance issues which reduce product life and are not economically feasible. Emissions tests for inappropriately lowly loaded larger engines would not be possible at their data plate rating since there is not enough compression available to fully load the engines. Forcing the de-rated operation of oversized engines in these installations will not benefit emissions performance or air quality.

LEC technologies are integrated in lean-burn engines rated above 1000 bhp. The Department acknowledges and references LEC technology as retrofit technology, referencing a 2015 U.S. EPA Technical Support Document that states "*LEC are described as retrofits that allow engines to operate on extremely lean fuel mixtures to minimize NOx emissions. The LEC retrofit may include: (1) redesign of cylinder head and pistons to improve mixing (on smaller engines),* *(2)* ***Pre-combustion chamber (on larger engines)****, (3) Turbocharger, (4) High energy ignition system, (5) Aftercooler, and (6) Air-to-fuel ratio controller." See* GCA Exhibit 11 (EPA CSAPR TSD) at p. 5-3 to 5-4 (emphasis added). As described in Appendix A-1, *Low Emissions Combustion (LEC) Technologies are integrated in lean-burn engines*, attached, all of the LEC technology is incorporated into these lean-burn engines with the exception of the pre-combustion chamber on the smaller G3500J LE 0.5g NOx per bhp-hr family of spark ignited lean-burn engine.

The greatest technology differentiator between the G3500J LE lean-burn family of engines and the G3600 A4 LE family of lean-burn engines is the G3600 A4 LE family of engine's improved charge air/fuel mixture ignition capabilities. This is due to the G3600 A4 LE's use of a pre-combustion chamber design made possible by the engine's significantly larger cylinder bore diameter.

The G3500J LE family of lean-burn engines with open chamber spark ignition emits NOx at levels that are half the federal New Source Performance Standard emissions requirement by providing NTE 0.5g NOx per bhp-hr site emissions. As shown in the Image 2, G3500 LE Open Chamber Spark Ignition Design, attached to this testimony, the spark plug is centrally located between the intake and exhaust ports and valves. There is not much room for the required engine coolant cooling passages to cool the exhaust seats, valves, ports and the spark plug. The spark plug gap provides the start of ignition which initiates a spherical flame front across the piston crown cup and later in the stroke across the entire piston diameter.

The G3600 A4 LE lean-burn pre-combustion chamber ignition of the extremely lean mixture in the main engine cylinder combustion chambers achieves both 0.5g and 0.3g NOx per bhp-hr on a site NTE basis. As shown in Image 3, G3600 A4 LE Lean-Burn Pre-Combustion Chamber Ignition, attached to this testimony, the additional space available in the much larger bore area of the G3600 A4 LE engine (three times (3X) the bore area of the G3500J LE engines) enables integration of the pre-combustion chamber and associated enhanced ignition of extremely lean main chamber mixtures. The process the pre-combustion chamber uses to provide ignition to the engine cylinders is as follows: the main chamber fuel is admitted into the engine cylinder intake port as the combustion air valve is open and admission ends before the intake engine valve is closed. A separate fuel supply to the pre-combustion chamber permits a small volume of gas into the pre-combustion chamber. The source of the air for the correct air/fuel ratio of the pre-combustion chamber is forced into the pre-combustion chamber during the compression stroke of the piston from the engine cylinder. A side-mounted spark plug in a lower position of the pre-combustion chamber ignites the not so lean pre-combustion chamber air/fuel mixture which initiates a flame front that reflects off the top of the pre-combustion chamber. The rapid spherical expansion of the flame front then jets out from each of the ports of the pre-combustion chamber across the engine cylinder piston crown. These burning plasma jets ignite the extremely lean air/fuel mixture in the main chamber. This combustion process provides a much faster, more complete, cooler combustion of the main chamber with a leaner air/fuel mixture than is possible with open chamber combustion.

The significantly larger family of G3600 A4 LE engines provide much more power per cylinder than the smaller G3500J LE family of engines. This large difference in power capability is made possible in part by several engine characteristics including larger bore diameter, bore area, longer stroke, larger cylinder displacement, higher torque per cylinder and greater Brake Mean Effective Pressure (BMEP) per cylinder. These differences in the space claims for BAT are more fully described in the attached Appendix A-2 to my testimony, and the differences in power related to engine size are more fully described in the attached Appendix A-3.

The significantly larger G3600 A4 LE engines provide more power than the G3500J LE engines. Table 2, Engine Model with NOx Capability Ratings, Torques, BMEP, presents the engine rating power, and torque (employing 54DegC or 130DegF separate circuit air coolant temperature ratings). This table reflects the greater engine displacement and BMEP of the G3600 A4 LE engine.

TABLE 2: Engine Model with NOx Capability Ratings, Torques, BMEP

Engine Model with NOx Capability Ratings, Torques, BMEP	Not To Exceed Emissions NOx/bhp-hr	Engine Rating bhp	Engine Torque lb-ft	Engine Displace-ment cu. in	BMEP psi
G3500J LE Engine Family	0.5 g NOx				185.3
G3512J LE	0.5 g NOx	1035	3,884	3,158	185.3
G3516J LE	0.5 g NOx	1380	5,177	4,211	185.4
G3520J LE	0.5 g NOx	1725	6,470	5,263	185.4
G3600 A4 LE Engine Family	0.3 & 0.5 g NOx				191.2
G3606 A4 LE	0.3 & 0.5 g NOx	1875	9,846	7,762	191.2
G3608 A4 LE	0.3 & 0.5 g NOx	2500	13,129	10,350	191.2

As shown in Table 3, Engine Family NOx Capability Ratings and Per-Cylinder Data, below, the smaller G3500J LE 0.5g NOper bhp-hr family of engines shown each have ratings greater than 1000 bhp, yet produce significantly lower engine torque than the G3600 A4 LE 0.3 & 0.5g NOx per bhp-hr family of engines. The larger G3600 A4 LE family of engines rating per cylinder is over 3.5 times that of the smaller G3500J LE 0.5g NOx per bhp-hr family of engines. The G3606 A4 LE engine is capable of 90% greater torque over the G3516J LE and greater than 50% greater torque over the G3520J LE engine. Torque at rated speed is what drives compressors, delivering needed gas flows at pressure. G3500J LE 0.5g NOx per bhp-hr engine displacements present a good indication the larger G3600 A4 LE engines are a significantly larger engine class providing greater efficiencies and lower emissions.

TABLE 3, Engine Family NOx Capability Ratings and Per-Cylinder Data

Engine Family NOx Capability Ratings and per Cylinder Data	Not To Exceed NOx/bhp-hr	Engine Rating bhp	Rating per Cylinder bhp	Cylinder Bore Area sq in	1 Cylinder Displacment cu. in	1 Cylinder Torque lb-ft
G3500J LE Engine Family	0.5 g NOx		86.25	35.3	264	324
G3512J LE	0.5 g NOx	1035	86.25	35.3	264	324
G3516J LE	0.5 g NOx	1380	86.25	35.3	264	324
G3520J LE	0.5 g NOx	1725	86.25	35.3	264	324
G3600 A4 LE Engine Family	0.3 & 0.5 g NOx		312.5	109.4	1290	1641
G3606 A4 LE	0.3 & 0.5 g NOx	1875	312.5	109.4	1290	1641
G3608 A4 LE	0.3 & 0.5 g NOx	2500	312.5	109.4	1290	1641

The external sizes and mass of the G3500J LE 0.5g NOx per bhp-hr family of engines and G3600 A4 LE 0.3g & 0.5g NOx per bhp-hr family of engines show the larger G3600 A4 LE class engines are significantly larger and heavier. As shown in Table 4, Engine Model with NOx Capability, below, the cubic volume of the G3606 A4 LE engine is 49% greater than the G3516J LE and 29% greater than the G3520J LE engine. Similarly, the mass of the G3606 A4 LE engine is 71% greater than the G3516J LE and 45% greater than the G3520J LE engine. Although this larger engine size is generally more efficient, it also requires significant additional investments in the package and site installation to provide adequate air, coolant and fuel cooling to enable these greater capabilities and result in the lower 0.3g NOx per bhp-hr exhaust emission rating. The heat rejection on a brake specific basis is lower on the larger G3600 A4 LE family of engines than the smaller G3500J LE family of engine. The smaller G3500J LE engine-driven gas compression packages perform a critical role in gas gathering, moving gas to larger gas compression packages to gas processing plants.

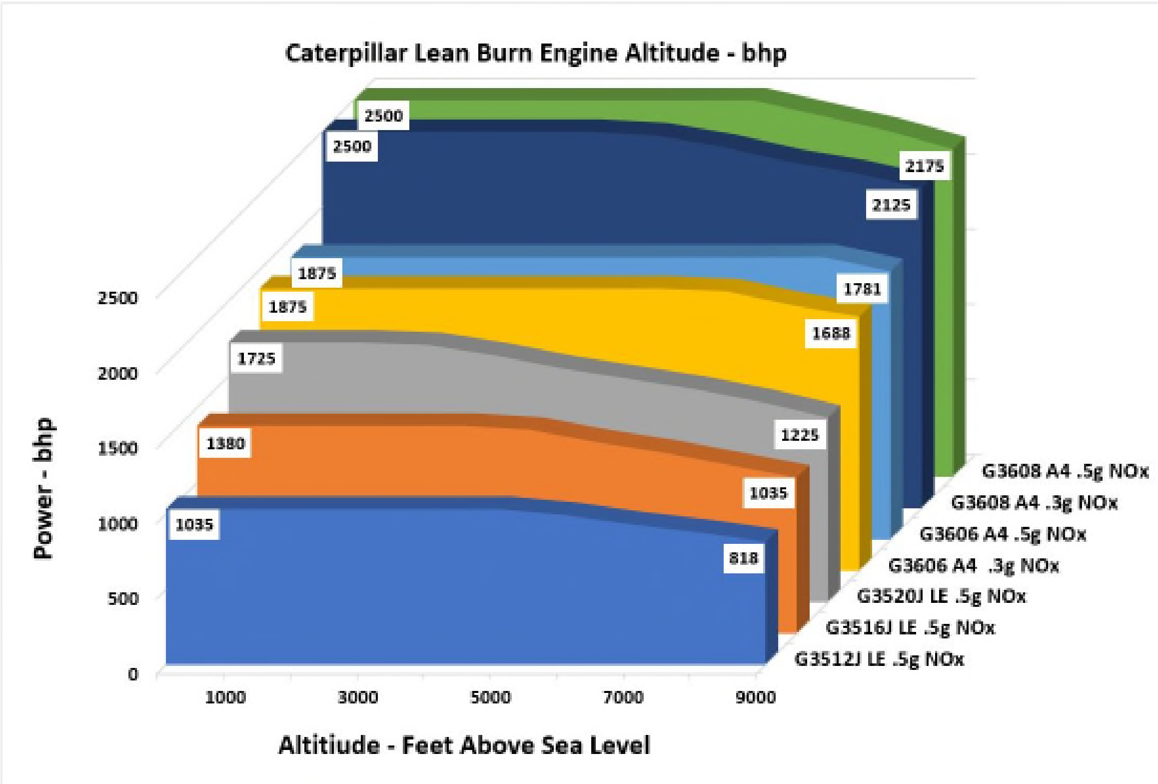
TABLE 4, Engine Model with NOx Capability

Engine Model with NOx Capability	Not To Exceed Emissions NOx/bhp-hr	Rating bhp	Length ft	Width ft	Height ft	Engine Space cu ft	Mass lb
G3500J LE Engine Family	0.5 g NOx						
G3512J LE	0.5 g NOx	1035	10	7.23	7.01	506.8	15611
G3516J LE	0.5 g NOx	1380	11.77	6.18	7.5	544.9	23777
G3520J LE	0.5 g NOx	1725	13.49	6.18	7.75	645.7	10785
G3600 A4 LE Engine Family	0.3 & 0.5 g NOx						
G3606 A4 LE	0.3 & 0.5 g NOx	1875	15.22	5.72	9.58	834	36638
G3608 A4 LE	0.3 & 0.5 g NOx	2500	18.5	7.42	9.58	1319	46500

(ii) The Proposed Engine Emission Standards are Lower Than the BAT of Today's Smaller G3500LE Spark Ignited Natural Gas Lean-burn Combustion Engines

The larger G3600 A4 LE spark ignited lean-burn natural gas engines have greater power and emissions capability than the G3500J LE engines. This is fundamentally because of greater flow of cooler combustion air. The greater intake air flow at cooler temperatures is possible through more effective on-engine technologies: exhaust driven turbochargers compress the charge air. It is then cooled through two stage intercooling. Although the G3500J LE engine has two-stage intercooling of the charge air, size constraints prevent it from being as efficient as on the larger class engine. The more efficient G3600 A4 LE engine turbochargers and two stage intercooler permit greater cooled air mass flow, which permits more fuel at the correct air/fuel mixture, and improves the engine's ability to develop power at altitude while cooling the air fuel mixture for combustion.

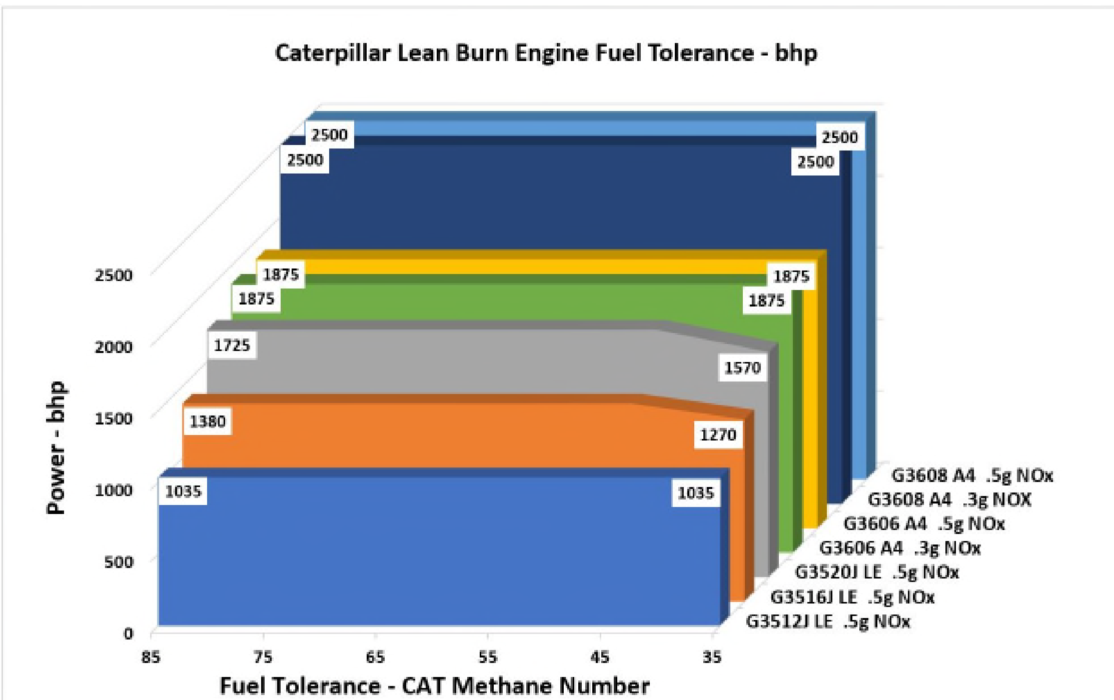
The chart below titled "Caterpillar Lean-burn Engine Altitude – bhp" presents the site power capability for each of the subject engines.



Site possible power is on the vertical axis and site altitude is on the horizontal axis. The three G3500J LE 0.5g NOx per bhp-hr engines are in the foreground whereas the four G3600 A4 LE 0.3g & 0.5g NOx per bhp-hr engine emissions ratings are the background objects. Note the G3606 A4 LE and G3608 A4 LE engines have two NTE emissions ratings (0.3g & 0.5g NOx) while the G3500J LE family of engines emissions is limited to one NTE 0.5g NOx per bhp-hr setting. The site power available for these ratings at higher elevations reflect the additional mass flow of cooled air required for the NTE emissions settings has been matched with additional fuel for very lean air/fuel combustion mixtures.

More combustion air at cooler temperatures aid in providing greater power with lower fuel quality. The larger class G3600 A4 LE engines have greater ability to provide cooler charge air in excess quantities than the smaller G3500J LE engines. This benefit is shown on the chart

"Caterpillar Lean-Burn Engine Fuel Tolerance – bhp." The application of the BAT to both the G3500J LE and G3600 A4 LE engines have resulted in much greater fuel tolerance than their predecessors. Note the larger more efficient G3600 A4 LE lean-burn engines do not have a derate even with hotter field gas fuels with a Caterpillar Methane Number of 35. (The Caterpillar Methane Number quantifies the combustion knock characteristics of a gaseous fuel mixture. The lower the CAT Methane Number the hotter the fuel, the more likely to cause combustion knock.) The G3516J LE and G3520J LE lean-burn engines do not begin their power derations until CAT Methane Number 45 with further derate when consuming fuels down to a Methane Number of 35.



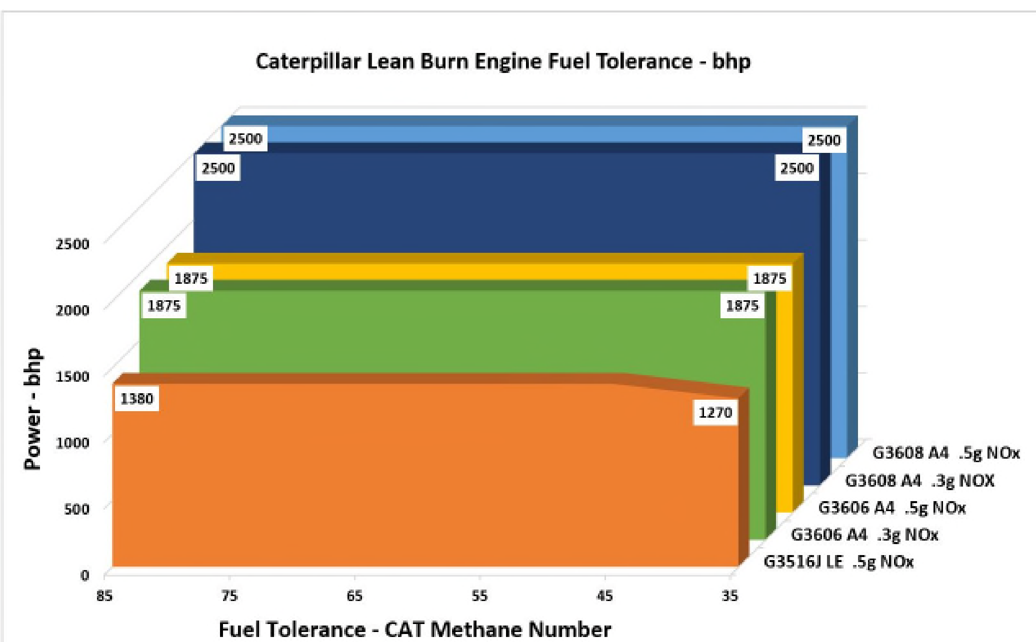
Of note, greater excess combustion air is required as the fuel mixture heating value increases (and the Caterpillar Methane number decreases). Natural gases hotter than methane CH_4 (911 BTUper cu ft) such as ethane C_2H_6 (1631 BTUper cu ft) and propane C_3H_8 (2353 BTUper cu ft) are associated gases in oil & gas reservoirs. Even small fractions of the associated field gases in the fuel mixture require additional excess air to maintain the needed lean air to fuel ratio to achieve 0.5 g NOx per bhp-hr. The G3500J LE lean-burn engines are only cabable of achieving 0.5 g NOx per bhp-hr for site Not to Exceed (NTE) emissions basis. The larger, more capable G3600 A4 LE lean-burn engines can provide more and cooler air for leaner combustion enabling it to achieve not only the 0.5g NOx per bhp-hr but also the lower 0.3g NOx per bhp-hr NTE emissions level rating.

Larger class engines require additional packaging for specific sites or ambient capabilities. A key to the package is the various cooling circuits have specific heat loads which must be dissipated to enable the engine to have the capability intended. John Dutton's direct written technical testimony, GCA Exhibit 12, provides a more detailed discussion of the package design, manufacture, transportation, installation, and commissioning for a specific engine model at a site rating and site emissions.

As currently proposed, the emission requirement at the power threshold of the Department's Proposed Rule at 20.2.50.113.B(3) NMAC is lower than the BAT for today's spark ignited natural gas lean-burn combustion engines. The challenge is that the 0.3gNOx per bhp-hr standard is lower than the current BAT emission rate for spark ignited natural gas lean-burn combustion engines available for three smaller engine models which have at least a 1000 bhp power rating. The reality is the natural gas compression packaging OEMs, and end-users have chosen to employ spark ignited lean-burn engines at 1380 bhp at 1400 rpm for a large fraction of the gas gathering space. The BAT for these greater than 1000 bhp engines is not capable of meeting the proposed 0.3g NOx perbhp-hr emissions level.

As shown in my testimony, the key issue is G3500J LE engines do not have a bore size sufficient to include a pre-combustion chamber ignition system. Engine bore size matters and is a distinction in this conversation. "Larger lean-burn" spark ignited engines more correctly define the G3600 A4 LE engine family and not the G3500J LE engines. The larger G3600 A4 LE family of engines have cylinder diameters providing over three times the cylinder bore area of the smaller G3500J LE family of spark ignited engines.

The chart below provides the effectiveness of BAT for the G3516J LE and the G3600 A4 LE lean-burn spark ignited compression engines. The 1380 bhp G3516J LE 0.5g NOx per bhp-hr NTE engine is shown in the foreground. The G3606 A4 LE and G3608 A4 LE 0.3g NOx per bhp-hr NTE and 0.5g NOx per bhp-hr NTE ratings are shown in the background. The site power is presented as a function of fuel tolerance represented by CAT Methane Number. The larger G3600 A4 LE family of lean-burn engines shown on this chart reflect the benefits of greater engine size and it pre-combustion chamber ignition technology. The larger G3600 A4 LE family of lean-burn engines reflect the BAT for larger lean-burn natural gas engines and achieves 0.3 g NOx per bhp-hr NTE emissions. Of lean-burn engines, only engines greater than 1875 bhp can achieve the 0.3 gper bhp-hr NOx limit!



(iii) The Proposed Engine Emission Standards are Unjustifiably Lower than Federal Engine Emission Standards.

The Proposed Rule, which sets forth a limit of 0.3g NOx per bhp-hr emissions for 1000 bhp and greater rated engines, is not in line with the applicable federal standards that apply to new engines. “New” reflects date of engine manufacture, not date of manufacture of an engine-driven compression package, nor the date of installation at a given site. In fact, this limit is significantly lower than the emissions requirements in US EPA 40 CFR 60, Subpart JJJJ for new, non-emergency lean-burn engines greater than or equal 500 but less than 1350 bhp: 1.0 g NOx per bhp-hr, 2g COper bhp-hr and 0.7g VOCper bhp-hr. The federal New Source Performance Standards (NSPS) for individual engines is appropriate unless in established NAA (Non-attainment Areas) where individual site permitting processes by NMED based on total emissions is more appropriate to limit specific sites or areas.

(iv) Applicability of the Engine Emission Standards Should Be Based on Date of Manufacture or Reconstruction

As proposed, 20.2.50.113.B(2), Table 1 NMAC and 2.2.50.113.B(3), Table 2 NMAC currently determine applicability based on whether an engine is “constructed, reconstructed, or installed” either before (Table 1) or after (Table 2) the effective date of the rule. The Proposed Rule determines new or existing standard applicability in a way that is not consistent with how the EPA determines applicability for spark-ignition engines, and that does not make sense from a functional standpoint. EPA’s standards for spark-ignition engines in 40 CFR Part 60, Subpart JJJJ bases applicability on the “date of manufacture” – which is when an engine is originally produced, or when it is reconstructed. See 40 CFR § 60.4230 (basing applicability on manufacture date) and 40 CFR § 60.4248 (defining “date of manufacture”).

The language in the Proposed Rule would consider an engine to be "new" (and therefore subject to the new engine emission standards in Table 2 of 20.2.50.113.B(3) instead of the existing engine emission standards in Table 1 of 20.2.50.113.B(2)) if it is relocated. As discussed above, the technology to achieve a certain NOx level for lean-burn engines is built into the engine, and it can be cost prohibitive if not technically infeasible to retrofit older engines with technology that was not part of the original design. An engine should not be considered "new" just because the engine is moved and "installed" at a new location. Relocation of compressor packages is common, and nothing about the relocation should provide a basis for converting the engine in that package from an existing engine into a new engine subject to significantly more-stringent emission standards.

The GCA has proposed to change the applicability triggers for new and existing engine emission standards under the Proposed Rule to make them consistent with the applicable federal standards and to avoid a new-source trigger based on "installation" at a new location. "Installed" should not be a criteria for determining if an engine is "new" as opposed to "existing." Determining the applicability of emission standards for engines only makes sense if based on the date of manufacture or reconstruction. The recommended changes to the horsepower levels and NOx limits in 20.2.50.113.B(2) Table 1 NMAC and 20.2.50.113.B(3) Table 2 NMAC that The GCA has recommended are predicated on and dependent upon these changes to how applicability of the emission standards is determined.

V. Conclusion

The greatest technology differentiator between the smaller G3500J LE Lean-burn engine family and the larger G3600 A4 LE lean-burn engine family is the G3600 A4 LE engine's improved charge air/fuel mixture ignition capabilities. This is due to the G3600 A4 LE engine's use of a pre-combustion chamber design made possible by its larger cylinder bore. The Proposed Rule at 20.2.50.113.B(3) NMAC ignores the fact that newly manufactured lean-burn engines rated between 1000 bhp and 1875 bhp cannot achieve the proposed NOx emission standard, even though BAT is already employed. As currently drafted, the Department's regulation requires engine emissions levels that are not available for lean-burn engines from 1000 up to 1875 bhp. For the reasons set forth herein, GCA's amendments to 20.2.50.113.B(3), Table 2, NMAC should be adopted, specifically by requiring the 0.3g NOx per bhp-hr BAT emissions for larger natural gas lean-burn engines at equal to or greater than 1875 bhp power level.

This concludes my direct technical testimony in this matter.

IMAGES

Image 1: Range of Caterpillar Power Options for Oil & Gas Applications

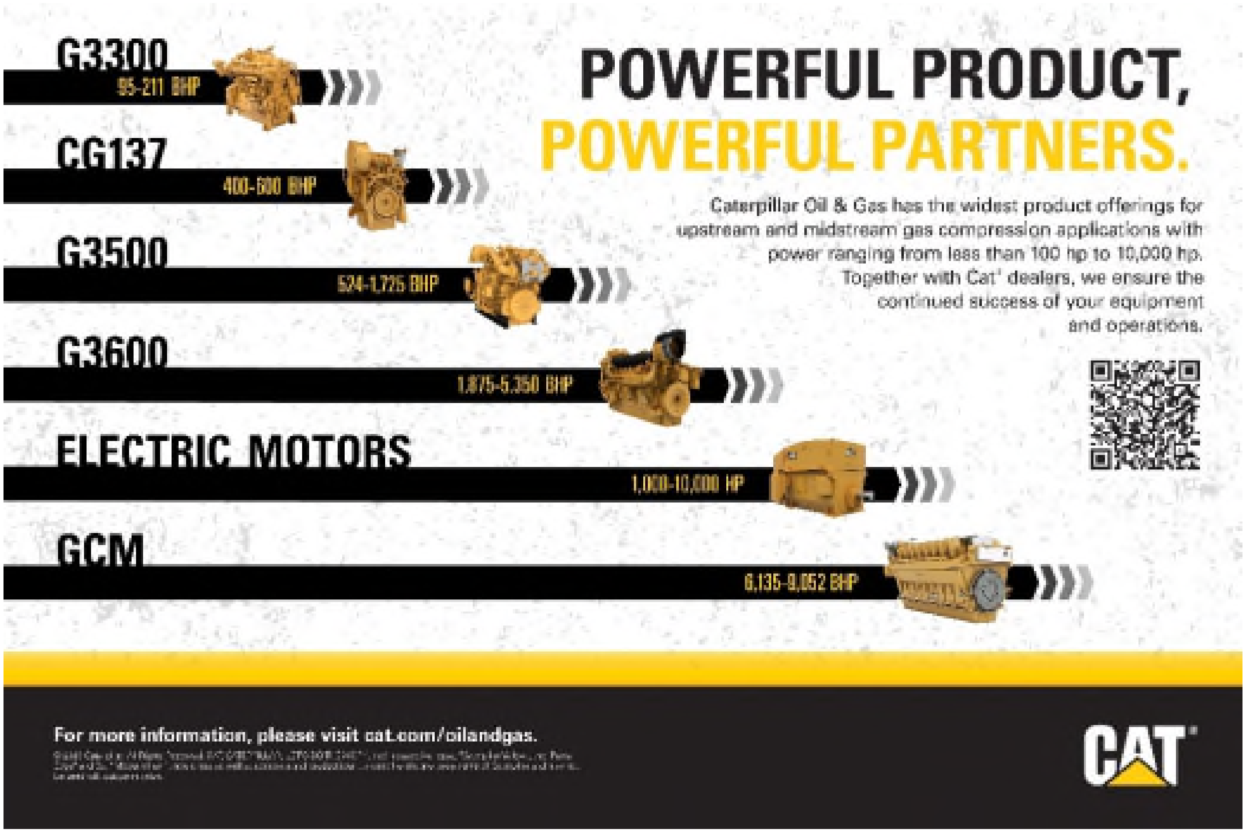


Image 2: G3500 LE Open Chamber Spark Ignition Design

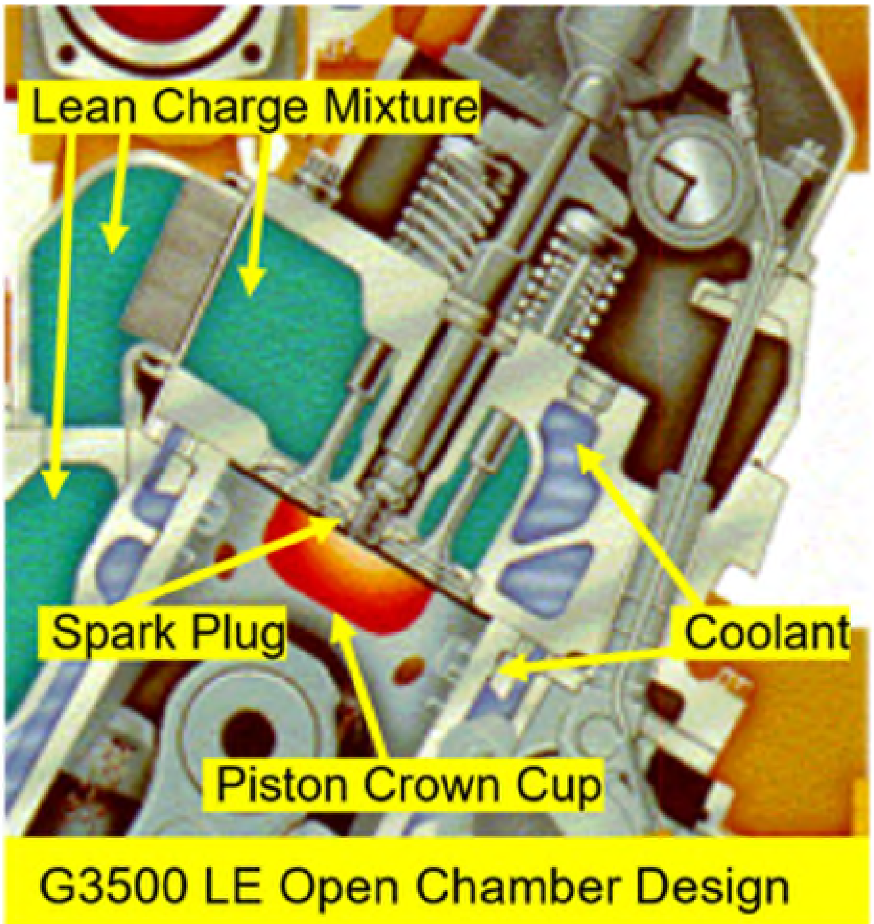
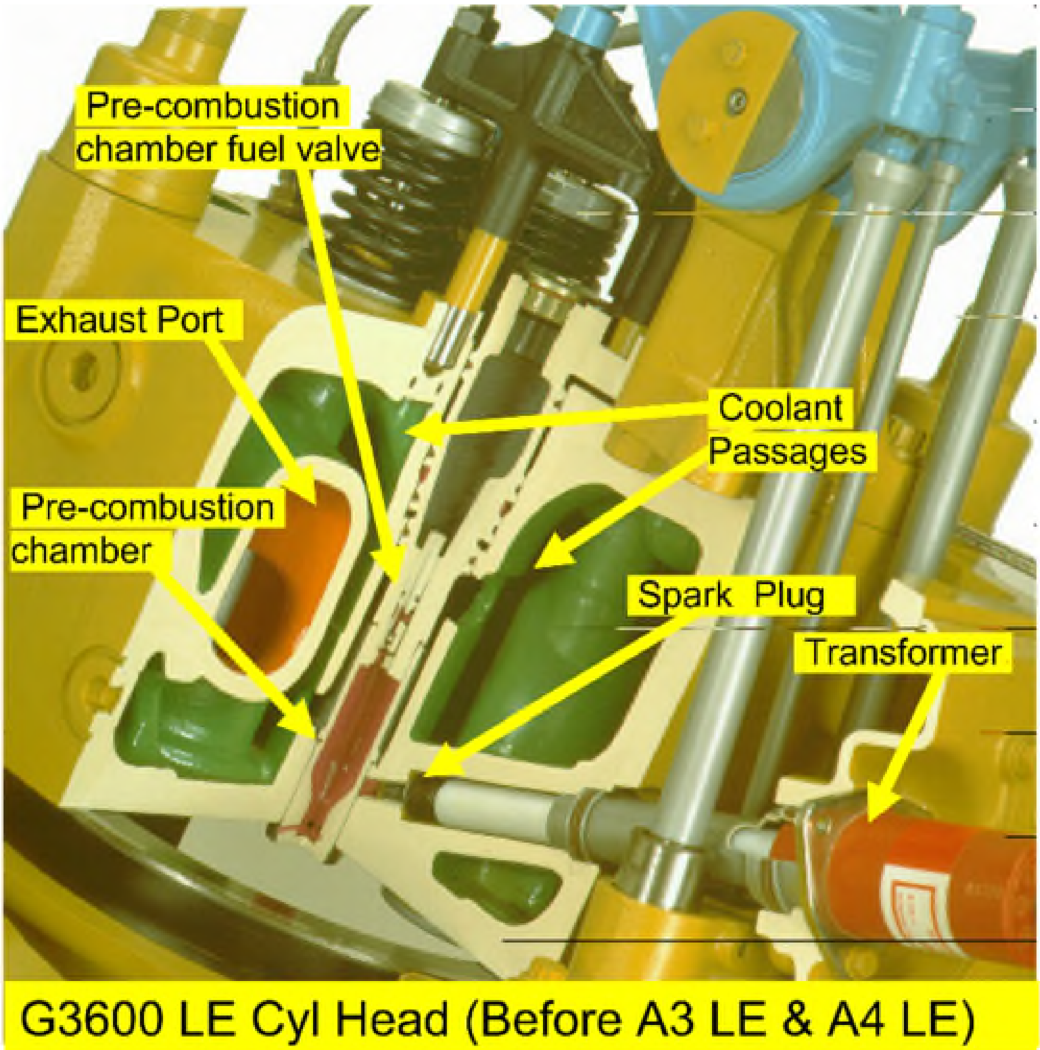


Image 3: G3600 A4 LE Lean-Burn Pre-Combustion Chamber Ignition

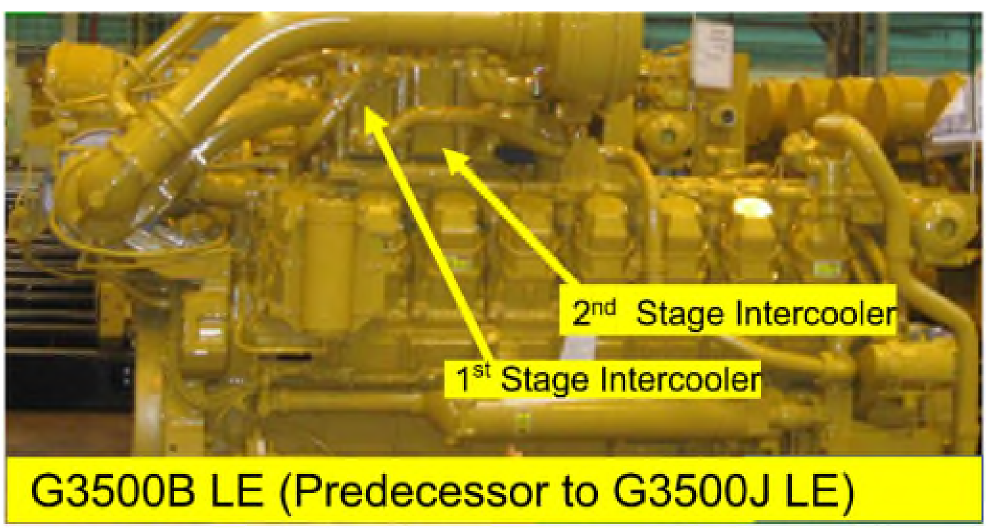


APPENDIX A-1:

Low Emissions Combustion (LEC) Technologies are integrated in lean-burn engines.

1. Low Emissions Combustion (LEC) Technologies are integrated in lean-burn engines rated above 1000 bhp. The Department references LEC technology as retrofit technology and cites a 2015 U.S. EPA document that states, "*LEC are described as retrofits that allow engines to operate on extremely lean fuel mixtures to minimize NOx emissions. The LEC retrofit may include: (1) redesign of cylinder head and pistons to improve mixing (on smaller engines), (2)* ***Pre-combustion chamber (on larger engines)****, (3) Turbocharger, (4) High energy ignition system, (5) Aftercooler, and (6) Air-to-fuel ratio controller.*" *See* GCA Exhibit 11 (EPA CSAPR TSD) at p. 5-3 to 5-4 (emphasis added). As described below, all of the LEC technology is incorporated into these lean-burn engines with the exception of the pre-combustion chamber on the smaller G3500J LE 0.5g NOx per bhp-hr lean-burn engine family.

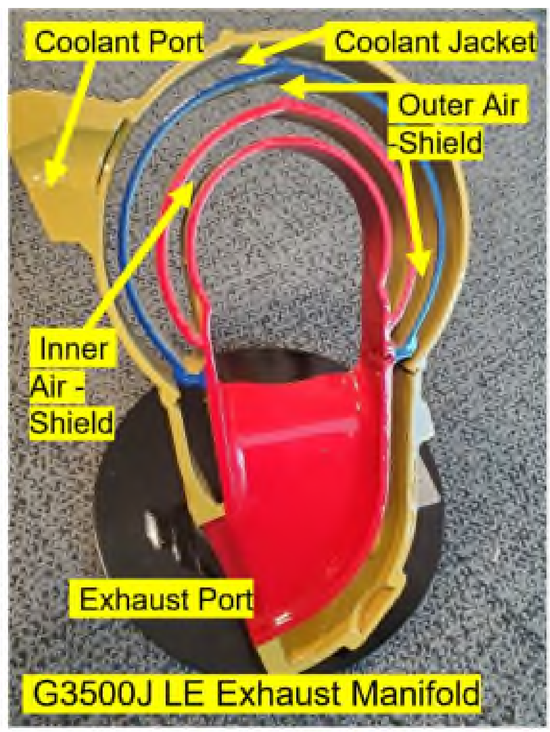
   1. Two-stage intercooling: engine jacket first stage and cooler separate circuit second stage. In the image the first stage (Engine Jacket Coolant) is on the left and the second



stage (Separate Circuit Aftercooler Coolant) at a cooler temperature is on the right.

2. The G3500J LE and G3600 A4 LE engines have forged instead of cast, larger turbocharger compressor wheels, coolant-cooled center bearing housings, and dry exhaust turbine housings. This move from cast compressor wheels was made for greater structural strength and durability. The center bearing housings need cooling to prolong bearing life. The exhaust turbine housings have been left dry to aid in delivering as much heat energy to the exhaust turbine wheel as possible, enabling greater air mass flow compressed to higher pressures.

3. The G3500J LE and G3600 A4 LE engines each have exhaust manifolds which provide hot exhaust to the turbochargers. The G3500J LE engine has double air-shielded and engine coolant-jacketed exhaust manifolds. The two key features of the G3500J LE engines: 1) cooler outside skin temperatures provided by the engine coolant jacket and 2) two concentric separate air jackets maintain heat in the exhaust gases to the exhaust turbine wheel of the turbochargers. The much larger G3600 A4 LE engine has dry cylinder exhaust elbows to a dry exhaust manifold. These dry exhaust manifolds deliver hot exhaust to the turbocharger exhaust turbine for greater boost pressure and flow available for the combustion charge intake air. The cylinder elbows and exhaust manifold and turbocharger exhaust turbine housings have hard wrap insulation to maintain greater heat transfer to the turbocharger exhaust turbine wheel.



4. Actuated exhaust gas bypass valve controls exhaust energy to the turbocharger exhaust turbine. As more exhaust energy is required because of site altitude or ambient temperature and pressures, the bypass valve is electronically controlled instead of a simple spring backed diaphragm wastegate, which was manually set for a site. A wastegate routes unneeded exhaust flow to the engine exhaust outlet. Both the G3500J LE and G3600 A4 LE engines incorporate this technology for greater flexibility of the resulting charge air boost.
5. The G3500J LE employs Fuel Mass Flow Actuators to meter gas into the turbocharger compressor inlet air flow, assuring more complete in-cylinder air fuel mixture combustion. This means of metering more accurately delivers the needed quantities of fuel. The G3600 A4 LE engines similarly employ an electronic flow device to fuel the main cylinder chamber fuel manifold.
6. The G3500J LE family of engines and the G3612 A4 LE and G3616 A4 LE lean-burn engines use an actuated turbocharger compressor bypass valve. This turbocharger compressor bypass valve is not available on the G3606 A4 LE nor the G3608 A4 LE engines. This turbocharger compressor bypass valve system provides more flexibility for varying site ambient and load control requirements. More boost is available when needed and the cooled charge is recirculated into the turbocharger compressor inlet when not needed. This compressor bypass system enables effective use of larger, more efficient turbochargers which provide additional beneficial boost to support higher altitude and higher ambient temperature sites. This charge air management system expands the use of the turbocharger's available operating range. It also makes cooled charge air / fuel mixture readily available for effective load acceptance.

APPENDIX A-2:

Space claims for Best Available Technologies on G3500J LE and G3600 A4 LE engines.

Much of the Best Available Technology (BAT) presented earlier is common to today's gas compression spark-ignited lean-burn combustion engines. Both the G3500J LE 0.5g NOx Engines and G3600 A4 LE 0.3g NOx & 0.5g NOx engines employ two-stage intercooling. The space claim for two-stage charge air intercooling make for tight on-engine "packaging" for improved cooling of turbocharger compressor out air flow. Although there may be some limitations on the smaller class G3500J LE engines in terms of desired efficiency of air and coolant flow which effect heat transfer rate and efficiency, the larger G3600 A4 LE engines provide greater space to enable more efficient heat transfer.

1. Both the G3500J LE and G3600 A4 LE lean-burn engines employ improved larger, forged turbocharger compressor wheels. The needed space claim is not great.
2. The smaller sized family of G3500J LE engines make the manufacture of air-shielded, engine coolant cooled exhaust manifolds possible. The larger size and taller geometry of the G3600 A4 LE lean-burn engines may have remote mounted coolers for the natural gas, engine coolant, and charge air cooler sections. This may permit hard insulation wrapped dry cylinder exhaust elbows and manifolds acceptable while delivering exceptional charge air flows and pressures.
3. Both the G3500J LE and G3600 A4 LE lean-burn engines employ actuated exhaust bypass valves. Space or volume claim to include for this technology is not an issue.
4. Both the G3500J LE and G3600 AR lean-burn engines employ actuated fuel mass control devices. Space claim for this technology is not an issue.

5. Both the G3500J LE family of engines and G3612 A4 LE and G3616 A4 LE lean-burn engines use an actuated turbocharger compressor bypass valve. Space claim for this technology is not an issue.

6. The greatest difference in the technologies applied to the G3500J LE and the G3600 A4 LE lean-burn engines is use of a pre-combustion chamber in the G3600 A4 LE 0.3g & 0.5g NOx engines. The space claim required for this technology is met with the larger class G3600 A4 LE engine.

7. G3600 A4 LE family of engines' bore diameter is 176% of the G3500J LE engines: 11. 8 inches vs. 6.7 inches. This much larger bore diameter provides room for greater air and fuel flow than possible in the smaller bore G3500J LE engines. The G3600 A4 LE family of engines cylinder bore diameter of 300mm (11.8inch) provides more than three (3) times the cylinder bore area of the G3500J LE family of engines: This additional area enables greater intake air and exhaust flow areas for a much larger rating per cylinder and engine torque. The larger geometry of the G3600 A4 LE family of engines enable the use of pre-combustion chamber ignition of the extremely lean main chamber mixture.

G3500J LE vs G3600 A4 LE Bore and Bore Area	Not To Exceed Emissions NOx/bhp-hr	Bore mm	Bore in	Bore Area sq in
G3500J LE Engine Family	0.5 g NOx	170	6.7	35.3
G3600 A4 LE Engine Family	0.3 & 0.5 g NOx	300	11.8	109.4

APPENDIX A-3:

More power per cylinder of G3600 A4 LE family of engines as compared to the G3500J LE family of engines. The significantly larger family of G3600 A4 LE engines provide much more power per cylinder than the smaller G3500J LE family of engines. This large difference in power capability is made possible in part by several engine characteristics including larger bore diameter, bore area, longer stroke, larger cylinder displacement, higher torque per cylinder and greater BMEP per cylinder:

1. G3600 A4 LE engine bore diameter is 176% of the G3500J LE engines: 11. 8 inches vs. 6.7 inches. This much larger bore diameter provides room for greater air and fuel flow than possible in the smaller bore G3500J LE engines.
2. G3600 A4 LE engine bore area is 310% of G3500J LE engine bore area: 109.4 square inches vs. 35.3 square inches.
   i) This additional cylinder bore area enables much greater cylinder-head area and related geography above the cylinder-head gasket combustion fire ring enabling much larger intake air and exhaust port flow areas yielding much greater rating and torque per engine cylinder.
   ii) The additional area of the G3600 A4 LE cylinder bore provides room for much greater engine coolant flow areas to cool the cylinder-head fire deck, the two exhaust ports and the **centrally mounted pre-combustion chamber**. This cooling capacity for the pre-combustion chamber is perhaps the greatest differentiator of why the G3600 A4 LE engines have the 0.3g NOx per bhp-hr NTE Site capability and the G3500J LE engines are limited to the 0.5g NOx per bhp-hr.

(1) Caterpillar and other compression ignition engine manufacturers and their OEMs have found diesel engine cylinder-heads provide significant cooling by the excess diesel fuel passing through the diesel fuel injector body.)

(2) A key problem with pre-combustion chamber engines is the critical need to prevent the pre-combustion chamber from becoming too hot acting similar to a "glow plug" which could provide an unintended ignition source for the next engine compression cycle. This "glow plug" ignition source would initiate combustion prior to the needed spark plug ignition. This pre-ignition can cause engine damage.

(3) Over sixty years ago, Caterpillar developed an inertial welding capability to uniformly fabricate thin-walled diesel engine pre-combustion chambers to enable greater heat transfer to the cylinder-head jacket coolant preventing early cylinder ignition.

iii) Additional cylinder-head area provides greater space for more structural iron or ductile-iron for greater strength, resisting increased cylinder pressures at elevated cylinder temperatures.

iv) Generally, structural limitations create thinner walls or structures specifically in/near the lower surface of the engine cylinder-head reduce cooling effectiveness and strength to reliably withstand cylinder pressure.

v) If the area or volume of iron is too space limited the expansion / contraction due to engine combustion temperatures and pressures over time, may initiate fatigue cracking.

vi) Stronger structures provide increased strength, combined with more effective engine jacket coolant passages and flow, enabling greater engine cylinder-head life.

3. G3600 A4 LE engine stroke is 157% of the G3500J LE engines stroke: 11.8 inch vs. the 7.5 inch
   i. The approximate one & one-half longer cylinder piston stroke than the G3500J LE engine provides greater combustion efficiency through longer combustion expansion phase.
   ii. Longer cylinder piston stroke may require slower crankshaft speeds to keep the piston velocity within the piston/ring/liner design specifications for durability/reliability and for combustion gas obturation preventing combustion gas blowing by the piston rings, contaminating the engine crankcase lubrication oil prematurely.
   iii. Longer cylinder piston stroke with slower engine speed enables longer intake and exhaust valve durations allowing more air for combustion and longer combustion expansion.
4. G3600 A4 LE engine individual cylinder displacement is 488% of the G3500J LE engines: 1290 cu.in vs. the 264 cu.in.
   i. The almost five times greater individual cylinder displacement than the G3500J LE engines, significantly reduces the number of cylinders needed to carry the engine load but requires greater total engine coolant heat rejection capability in the package installation. This larger G3600 A4 LE engine's brake specific heat rejection is lower than the smaller G3500J LE engines.
   ii. Greater individual cylinder displacement is an indication of a larger class of engine which typically has greater combustion efficiency and more control of combustion and emissions.

5. G3600 A4 LE engine torque per cylinder is 507% of G3500J LE engines: 1641 lb-ft vs. the 324 lb-ft.
    i. The five times greater torque per cylinder of the larger class G3600 A4 LE engine results in a fewer total number of engine cylinders and reduces the total number of engine components.
    ii. The greater torque per cylinder of the larger class G3600 A4 LE engine requires larger stronger components to transfer the total engine torque through the flywheel to driven equipment.
6. G3600 A4 LE engine has 3% greater Brake Mean Effective Pressure than G3500J LE engines: 191.2 psi vs. 185.3 psi.
    i. Much larger components and stronger structures are required to contain the combustion pressures of the much larger engine. This enables the G3600 A4 LE family of engines to operate reliably at 3% greater Brake Mean Effective Pressure (BMEP) over the G3500J LE family of engines.

ii. Greater BMEP is a measure of a higher level of cylinder pressure of the entire four cycles of combustion. This greater mean effective pressure over the larger cylinder area develops greater torque on the crankshaft pin for each cylinder.

Engine Model with NOx Capability Ratings, Torques, BMEP	Not To Exceed Emissions NOx/bhp-hr	Engine Rating bhp	Engine Torque lb-ft	Engine Displace-ment cu. in	BMEP psi
G3500J LE Engine Family	0.5 g NOx				185.3
G3512J LE	0.5 g NOx	1035	3,884	3,158	185.3
G3516J LE	0.5 g NOx	1380	5,177	4,211	185.4
G3520J LE	0.5 g NOx	1725	6,470	5,263	185.4
G3600 A4 LE Engine Family	0.3 & 0.5 g NOx				191.2
G3606 A4 LE	0.3 & 0.5 g NOx	1875	9,846	7,762	191.2
G3608 A4 LE	0.3 & 0.5 g NOx	2500	13,129	10,350	191.2

Vic Sheldon

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DIESEL & NATURAL GAS ENGINE POWER AND BUSINESS CONSULTANT

Qualifications: **Keen understanding of Electric Power Systems & Gas Compression Engines and Emissions Capabilities.**

Accomplished professional with strengths in engineering and marketing. Strong leader. Seasoned in business strategy, pursuing incremental business opportunities with short ROI. Expertise in diesel and gas mechanical & electric power generation systems.

Marketing & Market Development | Engineering | New Product Introduction | Product Launch, Development and Validation
Incremental Sales |Electric Power Systems | Oil & Gas Power | Mechanical Power Systems | Drill Rig & Gas Compression Engines
Natural Gas Engines | Dealer & Customer Relations | Leadership & Training | Persuasive Communicator

Professional Experience & Career Highlights

Business Strategy Experience: *Market Development/Marketing in Electric Power and Natural Gas & Diesel Engines*

Evaluated potential new incremental business opportunities, led design and release for manufacturing new engine configurations. Supported necessary product testing, application, installation, and product support information and materials.

- Surveyed, planned, and initiated an improved process evaluating incremental new power system business opportunities.
- Led engineering team delivering $23M incremental margin in 2014 to Caterpillar's Large Power Systems Division (LPSD) and Marine & Petroleum Products Division (MPPD), and Electric Power Division.
- Selected to Caterpillar's Gas Engine Enterprise Strategy Team (GEEST) – proposed a strategic vision to Caterpillar's Board of Directors furthering pursuit of natural gas systems in both diesel & natural gas engines across product offerings, resulting in a new natural gas engine engineering organization with internal profit and loss responsibilities.
- Assisted GCA companies communicate natural gas SI emissions capabilities to State Air Boards as limits were lowered through USC Title 40, Chap 1, Subchap C, Part 60 Subpart JJJJ (NSPS) and OOOO (Facility Modification or Reconstruction). Screened, interviewed, and assisted with selection of a full-time CAT Oil & Gas Power Systems Emissions Manager.
- Initiated and managed G3600 A4 New Product Introduction (NPI) through ongoing Voice of Customer updates from Gas Compression Packaging OEMs and end-using customers. (Increasing torque, improving fuel flexibility, lowering NOx 40%)
- Initiated development program for emissions upgrade kits for stranded end-user G3516 gas compression engines lowering its 2 g/bhp-hr NOx emissions to 0.5 g/bhp-hr. (Lowering NOx emissions 75%, half the national US EPA requirements.)
- Launched NPI program to design, develop, and manufacture new G3500 gas compression engines for US EPA NSPS 2nd stage, reducing NOx emissions 75%, increasing power at altitude, improving fuel tolerance, and reducing fuel consumption.

Leadership Experience: *Team Leadership/Training & Course Materials – Natural Gas Engines & US Army*

Promoted to Sr Market Professional at Caterpillar for critical expertise and passion, increasing gas engine application & industry growth through Caterpillar, Caterpillar Dealers & Industry Associations. Requested by name as Gas Engine Engineering Manager. Dept of Army Selection to Inspector General of a Theater Army Group and later, Group Commander in the US Army Reserve.

- Tactical Gas Engine Engineering Manager (Lafayette, IN) – Managed design & release for manufacturing new reciprocating engine power configurations. Team leadership through business case budgeting, defining performance and validation testing, effective application, installation, and creation of product support information and materials.
- Gas Engine Instructor, Caterpillar Learning Center (Peoria, IL) – Ensured relevance, appropriateness, timeliness, & quality of all training & materials supporting Caterpillar's industrial gas engine service training efforts worldwide.
  - Designed/prepared multimedia technical training materials/conducted service training & diagnostic courses.
  - Oversaw installation & maintenance of 3 natural gas generator sets, and support equipment enabling their use.
  - Initiated and established certified regional gas engine training centers, certifying gas engine service training instructors of five regional gas engine training centers (Texas, Florida, Alberta, Singapore, & Spain).
- Commander, 1st Sim Gp(Combat Arms), 1st Bde(Battle Command & Staff Training), 85th Div (Training). Directed planning, preparation & execution of Battle Simulation Exercises through deliberate 24-month cycle schedules of separate brigades and divisions of U.S. Army National Guard. (As a COL, US Army Reservist, had 4 COL & 2 LTC direct reports and 14 Full Time Unit Support (RA & Active Guard Reservists) augmenting 92 US Army Reservists. Senior rated 16 LTCs.)
- Assistant Commandant (Fld Arty), 5030th US Army RFS, (Indianapolis, IN) – Led development of arty training plans, POIs and aids improving effectiveness of Artillery (NCOES) & Advanced NCOES for 5 state area. (11 officers, 18 Sr NCOs, 32 NCOs)

Professional Job History

VSheldon JEverett Decisions, LLC The Villages, Fl | 2016 – Present: General Manager

Caterpillar Inc.-Large Power Systems Div. Lafayette, IN | 2013 – 2015: Engineering Manager

Caterpillar Oil & Gas Group, Marine & Petroleum Products Div., Houston, TX | 2003 -- 2013:
Sr. Marketing Professional (2011–2013); Market Professional (2008–2011); Market Development Consultant (2003–2008)

Caterpillar Rail & Petroleum Power Products – Engine Div., Achim bei Bremen & Kiel, Germany and Houston, TX | 2001 – 2003:
Market Development Consultant

Caterpillar Natural Gas Engines – Engine Service Training Div., East Peoria and Peoria, IL | 1996 – 2001: Training Consultant

Additional Caterpillar Experience

Senior Design Engineer | Application Engineer | Senior Product Quality Engineer
Gas Engine Manufacturing Liaison Engineer | Test Engineer

Military Experience

Commander, 1st Sim Gp, 1st Brigade (Battle Command & Staff Training), 85th Trng Div (Chicago, IL) – US Army Reservist

Inspector General, 19th Theater Army Area Command-Korea (CONUS Augmentation) (Des Moines, IA) – US Army Reservist

Commander, 4th Battalion, 75th Field Artillery, 303rd Ordnance Group (Peoria, IL) – US Army Reservist

US Army Command & General Staff Officer Course Student (Fort Leavenworth, KS) – US Army Reservist

Field Artillery Battalion Operations Officer, 4th Battalion, 17th Field Artillery (Raleigh, NC) – US Army Active Guard Reservist

Commander, Battery A, 4th Battalion, 75th Field Artillery, 434th Field Artillery Brigade (Peoria, IL) – US Army Reservist

Military Intelligence Officer (S2), 2nd Battalion, 75th Field Artillery, V Corps Artillery (Hanau, West Germany) – US Army RA Officer

Education, Professional Development & Affiliations

Master of Business Administration (MBA), Business – Indiana Wesleyan University

Bachelor of Science, Mechanical Engineering – Purdue University

Certification – Registered Professional Engineer (ME) Illinois: 602-040579

Awards & Recognition

2014 Caterpillar Chairman's Award Finalist – Product/Service/Solution Sustainability (Team Effort) – G3516 Low Emissions Kit

US Patents: 4,206,725 Injection nozzle clamp, June 10, 1980;
7,886,705 Engine system dedicated thermal management system, February 15, 2011;
8,037,872 Engine system having cooled and heated inlet air, October 18, 2011

Legion of Merit – U.S. Army (30 Years Distinguished Service)

Meritorious Service Medal – 2 Oak Leaf Clusters (Outstanding Meritorious Service as Battalion & Group Commander)

Army Commendation Medal – 2 Oak Leaf Clusters (Command & General Staff Course Instructor; Deputy Commandant-Field Arty)

Army Reserve Components Achievement Medal – 4 Oak Leaf Clusters

National Defense Service Medal – Bronze Service Star (Service during Vietnam and Desert Storm Eras)

Order of Saint Barbara – US Army Field Artillery Association Honorary

US Army Infantry School - Airborne and Ranger Courses

Technical Support Document (TSD)
for the Cross-State Air Pollution Rule for the 2008 Ozone
NAAQS Docket ID No. EPA-HQ-OAR-2015-0500

Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance

U.S. Environmental Protection Agency
Office of Air and Radiation

November 2015

GCA Exhibit 11

1 Introduction/Purpose

The purpose of this Technical Support Document (TSD) is to discuss the currently available information on emissions and control measures for sources of NOx other than electric generating units (EGUs). This information provides more detail about why EGUs are the focus of the proposed rulemaking, namely the uncertainty that exists regarding whether significant aggregate NOx mitigation is achievable from non-EGU point sources by the 2017 ozone season, and the fact that the limited available information points to an apparent scarcity of non-EGU reductions that could be accomplished in this timeframe. Notwithstanding these conclusions as regards the 2017 ozone season, the EPA continues to assess the role of NOx emissions from non-EGU sources to downwind nonattainment problems, and welcomes comments on the information in this TSD both as it relates to the current rule and for future use.

This TSD begins by briefly discussing the non-EGU emissions inventories used in this proposed rule, both for the 2011 base year and 2017 future baseline assessed for this proposed rule. The TSD then presents an evaluation of whether non-EGU emissions can be reduced in a cost-effective manner for particular categories. Then, it assesses the available NOx emission reductions from such categories and presents the category-by-category emissions reduction potential. This assessment considers and presents the costs per ton of these reductions, with a focus on technologies that achieve cost-effective reductions within a range of costs similar to that evaluated for EGUs. Finally, the TSD presents estimates of the time required to install and implement the control measures, both for comparison to the 2017 compliance timeframe, and for discussion of installation time should such measures be required in the future.

For the reasons stated in the preamble, the data and discussion in this TSD are intended to focus on the eastern states that are the focus of the Cross-State Air Pollution Rule (CSAPR). Information inclusive of western states[1] is presented where available and appropriate.

[1] For the purpose of this action, the western U.S. (or the West) consists of the 11 western contiguous states of Arizona, California, Colorado, Idaho, Montana, New Mexico, Nevada, Oregon, Utah, Washington, and Wyoming, and the eastern U.S. (or East) consists of the remaining states in the contiguous U.S.

2 Background

In this section we present annual and ozone-season NOx emission inventory totals and the relative percentages for non-EGU source categories statewide and/or nationally. This information is summary in nature and is not meant to replace other, more detailed information available from the EPA, such as the EPA's 2011v6.2 Emissions Modeling Platform TSD[2] as well as the Notice of Data Availability[3] (NODA) and Regulatory Impact Analysis[4] (RIA) for this proposed rulemaking.

Table 1 lists 2011 and 2017 projected NOx emissions by sector, in summary form, for the 48 contiguous states of the U.S. (CONUS).

Table 1: 2011 Base Year and 2017 Projected NOx Emissions by Sector (tons), for the 48 CONUS

Sector	2011 NO_x, annual	2017 NO_x, annual	2011 NO_x, ozone season	2017 NO_x, ozone season
EGU-point	2,000,000	1,500,000	942,000	689,000
NonEGU-point	1,200,000	1,200,000	515,000	502,000
Point oil and gas	500,000	410,000	213,000	172,000
Wild and prescribed fires	330,000	330,000	165,000	165,000
Nonpoint oil and gas	650,000	690,000	275,000	293,000
Residential wood combustion	34,000	35,000	3,000	3,000
Other nonpoint	760,000	730,000	204,000	211,000
Nonroad	1,600,000	1,100,000	825,000	582,000
Onroad	5,700,000	3,200,000	2,417,000	1,329,000
C3 Commercial marine vessel (CMV)	130,000	130,000	58,000	58,000
Locomotive and C1/C2 CMV	1,100,000	910,000	451,000	384,000
Biogenics	1,000,000	1,000,000	630,000	630,000
TOTAL	**15,000,000**	**11,200,000**	**6,698,000**	**5,018,000**

It is clear from Table 1 that NOx emissions are projected to remain constant or decrease for most sectors in the 48 states between 2011 and 2017. Emissions from the non-EGU point source sector and the other nonpoint source sector are not projected to change significantly, while emissions from the nonpoint oil and gas source sector are projected to grow (approximately 6%), during this time period. Based on the values in Table 1, Figures

[2] Technical Support Document (TSD), Preparation of Emissions Inventories for the Version 6.2, 2011 Emissions Modeling Platform, August 2015, available at: http://www3.epa.gov/ttn/chief/emch/2011v6/2011v6_2_2017_2025_EmisMod_TSD_aug2015.pdf

[3] Notice of Availability of the Environmental Protection Agency's Updated Ozone Transport Modeling Data for the 2008 Ozone National Ambient Air Quality Standard (NAAQS). The official version is available in the docket for this proposed rulemaking.

[4] Regulatory Impact Analysis for the Proposed Cross-State Air Pollution Rule (CSAPR) for the 2008 Ozone National Ambient Air Quality Standards (NAAQS). The official version is available in the docket for this proposed rulemaking.

1 and 2 show the relative contributions of the various sectors to overall NOx emissions (left panel) and for the non-EGU sectors (right panel) for 2011 and 2017, respectively.

Figure 1: 2011 NOx emissions by sector, with further non-EGU breakout (48 states)

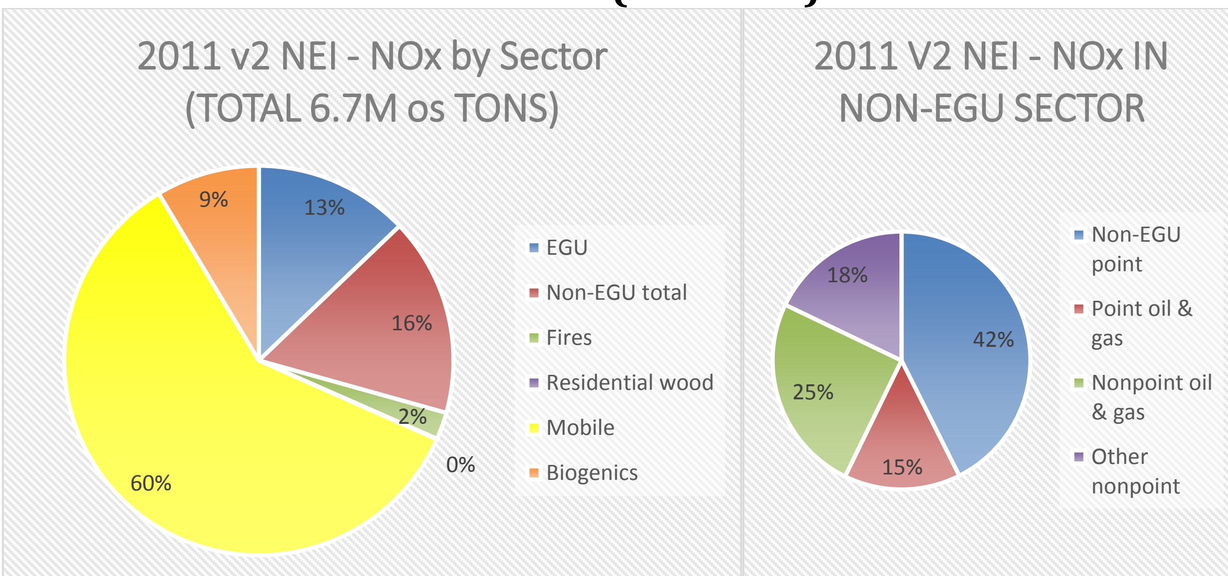

Figure 2: Projected 2017 NOx emissions by sector, with further non-EGU breakout (48 states)

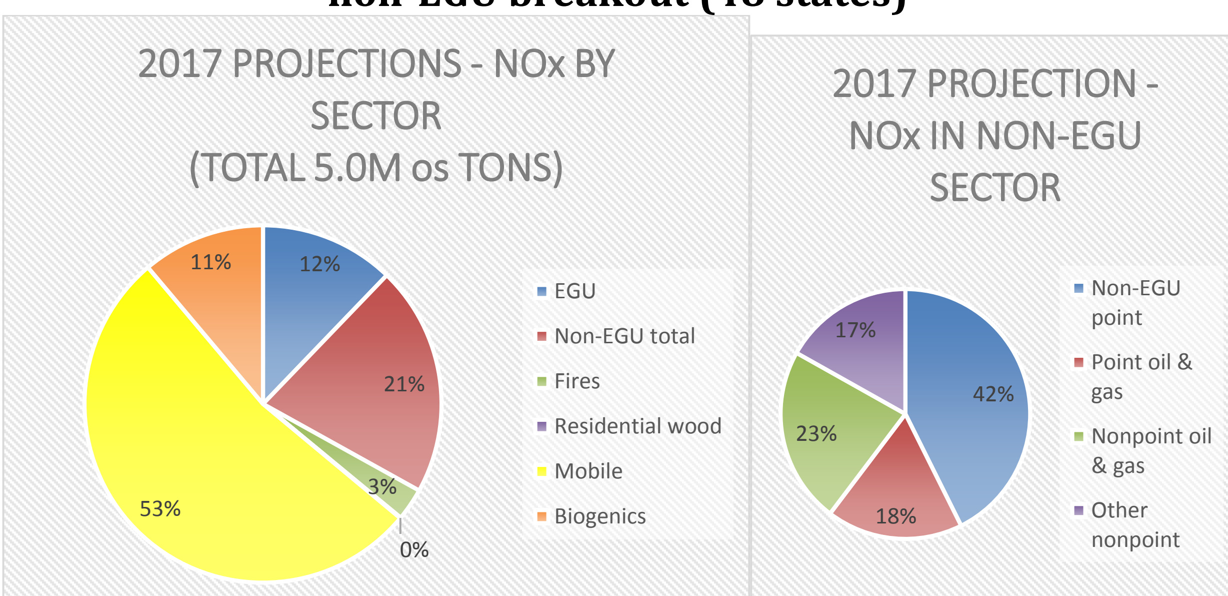

Figure 1 depicts total ozone season NOx emissions of 6,698,000 tons in 2011 and Figure 2 depicts total ozone season NOx emissions of 5,018,000 tons in 2017. In both 2011 and 2017, the mobile source sector has the largest NOx emissions. Substantial reductions in mobile source NOx are projected to occur by 2017. Mobile sources are projected to decrease because of sector-specific standards related to fuels, fuel economy, pollution controls, and repair and replacement of the existing fleet. Because these reductions are already expected to occur, mobile source emission reductions are not included in this analysis of non-EGU emission reductions achievable by the 2017 ozone season.

For the purposes of preliminary analysis in this TSD, "non-EGU total" refers to four separate categories of sources: non-EGU point, point oil and gas, nonpoint oil and gas, and other nonpoint (and does not include mobile sources). The oil and gas point and nonpoint sources are separated from the remaining non-EGU point and nonpoint sources due to the magnitude of their contribution to the inventory and other aspects related to the inventory development, emissions modeling, and future year projections for that industry. The point oil and gas sources are also separated out from the other non-EGU point sources according to the NAICS code specified for the various sources. Note that point oil and gas sources include a variety of types of processes, and there is overlap with the processes included in the rest of the non-EGU point inventory. More information on the emissions sectors is available in the 2011v6.2 Emissions Modeling Platform TSD.

Comparing the proportions of the total inventory for non-EGUs (Figures 1 and 2), it becomes clear that, although they are decreasing in the absolute sense, non-EGU NOx emissions are becoming a larger share of overall ozone-season NOx emissions (16% in 2011 compared with 21% in 2017).

Table 2 compares statewide projected total anthropogenic NOx emissions (inclusive of all sectors listed in Table 1 with the exception of fires and biogenics) for the 2017 ozone season to non-EGU NOx emissions for the 2017 ozone season for each of the 48 contiguous states of the U.S. Totals are given for the 48 contiguous United States (the 37 eastern states plus D.C. that are addressed in the proposed rulemaking are highlighted below in blue). Non-EGU sources in this table are broken down into two groups (non-EGU point sources, including point oil & gas sources, and other nonpoint and nonpoint oil & gas sources).

Table 2: Projected Total Anthropogenic Ozone-Season NOx Emissions vs. Projected Non-EGU Source Group NOx Emissions, 2017 Projections, Tons[5]

State	Total Anthropogenic	Non-EGU Point + Oil & Gas Point	% Anthro	Oil & Gas Nonpoint+ Other Nonpoint	% Anthro	Oil & Gas Point + Oil & Gas Nonpoint	% Anthro
Alabama	88,805	22,187	25	7,952	9	7,442	8
Arizona	71,906	5,015	7	2,310	3	612	1
Arkansas	69,737	13,400	19	5,308	8	9,164	13
California	236,322	29,342	12	20,220	9	3,105	1
Colorado	90,756	19,594	22	16,899	19	27,284	30
Connecticut	17,672	1,105	6	2,626	15	98	1
Delaware	7,786	628	8	615	8	0	0
District of Columbia	2,252	212	9	312	14	0	0
Florida	177,514	16,293	9	7,543	4	1,112	1
Georgia	103,536	18,816	18	4,559	4	1,495	1
Idaho	27,893	3,752	13	1,989	7	503	2
Illinois	148,178	24,668	17	15,409	10	9,424	6
Indiana	139,133	27,222	20	6,864	5	5,931	4
Iowa	70,467	7,888	11	3,861	5	153	0
Kansas	79,939	6,968	9	12,619	16	10,697	13
Kentucky	106,830	11,456	11	11,905	11	12,251	11
Louisiana	173,330	45,506	26	30,160	17	31,503	18
Maine	17,576	4,639	26	809	5	26	0
Maryland	46,029	6,213	13	3,508	8	522	1
Massachusetts	35,369	4,144	12	4,807	14	105	0
Michigan	131,486	21,867	17	12,245	9	9,398	7
Minnesota	89,328	15,541	17	6,414	7	46	0
Mississippi	54,832	11,684	21	2,122	4	6,557	12
Missouri	101,035	9,238	9	3,594	4	122	0
Montana	38,504	2,948	8	3,630	9	3,390	9
Nebraska	70,005	3,884	6	1,163	2	467	1
Nevada	28,192	4,018	14	1,003	4	115	0
New Hampshire	8,932	680	8	1,028	12	0	0
New Jersey	52,743	4,544	9	5,506	10	173	0
New Mexico	65,263	10,559	16	19,940	31	27,759	43
New York	109,910	13,738	12	14,624	13	904	1
North Carolina	98,064	15,711	16	3,657	4	1,203	1
North Dakota	74,118	4,047	5	18,125	24	19,185	26
Ohio	160,110	21,280	13	11,617	7	2,906	2
Oklahoma	131,763	32,203	24	33,178	25	51,257	39
Oregon	40,507	6,130	15	4,348	11	365	1
Pennsylvania	174,664	23,735	14	33,508	19	26,713	15

[5] EGUs are not provided a separate breakout in Table 2 since state-level emissions are presented in the emissions modeling platform TSD and other TSDs for this proposal.

State	Total Anthropogenic	Non-EGU Point + Oil & Gas Point	% Anthro	Oil & Gas Nonpoint+ Other Nonpoint	% Anthro	Oil & Gas Point + Oil & Gas Nonpoint	% Anthro
Rhode Island	5,845	544	9	1,370	23	12	0
South Carolina	55,897	10,144	18	3,980	7	348	1
South Dakota	22,192	1,241	6	432	2	75	0
Tennessee	85,759	13,494	16	5,846	7	1,922	2
Texas	467,245	95,671	20	115,180	25	145,285	31
Tribal Data	26,717	3,799	14	0	0	3,700	14
Utah	66,486	8,004	12	9,781	15	9,349	14
Vermont	5,473	163	3	937	17	0	0
Virginia	87,754	14,039	16	7,318	8	4,775	5
Washington	75,833	8,666	11	1,150	2	164	0
West Virginia	64,839	9,678	15	12,642	19	16,723	26
Wisconsin	75,047	11,181	15	5,351	7	178	0
Wyoming	68,864	26,488	38	4,018	6	10,905	16
Eastern States	***3,411,193***	***545,649***	***16***	***418,692***	***12***	***378,171***	***11***
US Total	***4,248,436***	***673,964***	***16***	***503,980***	***12***	***465,421***	***11***

Table 2 indicates that, in the projected 2017 inventory, non-EGU sources comprising non-EGU point and point oil and gas sources are estimated to make up 16% of anthropogenic NOx emissions in the 48 contiguous United States. In individual states, the percentage of anthropogenic emissions contributed by these two non-EGUs categories range from 3% to 26% (eastern states) and from 7% to 38% (western states).

We also note that in the projected 2017 inventory, non-EGU sources comprising nonpoint oil & gas and other nonpoint sources are estimated to make up 12% of anthropogenic NOx emissions in the entire continental U.S. In individual states, the percentage of anthropogenic emissions contributed by these non-EGUs ranges from 2% to 25% (eastern states) and from 4% to 31% (western states).

The EPA's preliminary analysis indicates that NOx emissions from oil and gas sources (inclusive of emissions from the point oil and gas and nonpoint oil and gas sectors) comprise an average of 11% of the total ozone season NOx emissions inventory. For some states, this percentage increases up to 43%, with oil and gas emissions exceeding non-EGU point totals in a number of states. The key sources of NOx emissions in the oil and gas sector are from the combustion of fossil fuel (primarily drilling rigs, internal combustion (IC) engines and pipeline compressors) and flares. Please refer to the EPA's 2011v6.2 Emissions Modeling Platform TSD for more information on emissions from these sectors.

3 Preliminary Analysis

For the purposes of this proposed rule, the EPA performed a preliminary analysis to characterize whether there are non-EGU source groups with a substantial amount of available cost-effective NOx reductions achievable by the 2017 ozone season.

3.1 Methodology

The EPA's preliminary analysis of potential non-EGU NOx emission reductions was performed using the Control Strategy Tool (CoST). CoST is the software tool the EPA uses to estimate the emission reductions and costs associated with future-year control strategies, and then to generate emission inventories that result from the control strategies applied. CoST tracks information about control measures, their costs, and the types of emissions sources to which they apply. The purpose of CoST is to support national- and regional-scale multi-pollutant analyses, primarily for Regulatory Impact Analyses (RIAs) of the National Ambient Air Quality Standards (NAAQS). CoST is also a component of the Emissions Modeling Framework (EMF) that was used to generate the 2017 non-EGU emissions presented above and in the Emissions Modeling Platform TSD for this proposal. Further discussion and documentation of CoST is available on the EPA's website at http://www.epa.gov/ttnecas1/cost.htm.

Appendices to this TSD discuss recommendations for updates to CoST, including corrections for inapplicable controls, sources already controlled by state rules, sources with permit limits or that clearly identified controls in place, and sources subject to future NOx emission limits. Appendix A summaries RTI's work to review estimates for lean burn IC engines, glass manufacturing, ammonia reformers, and gas turbines.[6] Appendix B discusses SRA's work on a variety of other categories including many of the others evaluated in this TSD.[7]

It should be noted that all of the NOx measures included in this report are currently in the Control Measure Data Base (CMDB) used by CoST, and do not reflect the updates suggested in these contractor reports. Obstacles to full incorporation of the recommended changes include availability of accurate costs for these measures, and to have cost equations rather than average cost/ton to estimate costs. Control efficiencies are readily available for measures, but costs, particularly those that can be estimated using equations that consider source size or capacity, often are not. The EPA plans to incorporate these recommendations for changes or additions to the NOx controls for non-EGUs to support NOx control efforts for future rules and other efforts. Nonetheless, the information from these reports helped inform our assessment in terms of uncertainty surrounding non-EGU emission reduction potential. Further details on the CMDB can be found on the CoST web site.

For the purpose of identifying a list of non-EGU NOx source groups with controls available, the EPA ran CoST including non-EGU sources for the 37 eastern U.S. with NOx emissions of greater than 25 tons/year in 2017. These reports are included in the Appendices of this TSD. Through a contractual agreement with EPA, SRA International and RTI International provided reports which CoST examined a number of source categories of non-EGUs with control costs up to $10,000 per ton (in 2011 dollars). CoST selected particular control

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[6] "Update of NOx Control Measure Data in the CoST Control Measure Database for Four Industrial Source Categories: Ammonia Reformers, NonEGU Combustion Turbines, Glass Manufacturing, and Lean Burn Reciprocating Internal Combustion Engines," Revised Draft Report, RTI International, 2014.

[7] "Review of CoST Model Emission Reduction Estimates," SRA International, 2014; "Summary of State NOx Regulations for Selected Stationary Sources," SRA International, 2014.

technologies based on application of a least-cost criterion for control measures applied as part of control strategy. Other NOx control measures are available for some of these categories, but on average annualized costs for these measures were at higher cost.

3.2 Uncertainties and Limitations

The EPA acknowledges several important limitations of the non-EGU cost analysis included in this TSD, which include the following:

Boundary of the cost analysis: In this engineering cost analysis we include only the impacts to the regulated industry, such as the costs for purchase, installation, operation, and maintenance of control equipment over the lifetime of the equipment. Recordkeeping, reporting, testing and monitoring costs are not included. Additional profit or income may be generated by industries supplying the regulated industry, especially for control equipment manufacturers, distributors, or service providers. These types of secondary impacts are not included in this cost analysis.

Cost and effectiveness of control measures: Our application of control measures reflect nationwide average retrofit factors and equipment lives. We do not account for regional or local variation in capital and annual cost items such as energy, labor, materials, and others. Our estimates of control measure costs may over- or under-estimate the costs depending on how the difficulty of actual retrofitting and equipment life compares with our control assumptions. In addition, our estimates of control efficiencies for control measures included in our analysis assume that the control devices are properly installed and maintained. There is also variability in scale of application that is difficult to reflect for small area sources of emissions.

Discount (Interest) rate: Because we obtain control cost data from many sources, we are not always able to obtain consistent data across original data sources. If disaggregated control cost data are not available (i.e., where capital, equipment life value, and operation and maintenance [O&M] costs are not shown separately), the EPA assumes that the estimated control costs are annualized using a 7 percent discount rate, which is the discount (interest) rate used in accordance with OMB guidance in Circular A-94. In general, we have some disaggregated data available for non-EGU point source controls. In addition, while these interest rates are consistent with OMB guidance, the actual interest rates may vary regionally or locally.

Accuracy of control costs: We estimate that there is an accuracy range of +/- 30 percent for non-EGU point source control costs. This level of accuracy is described in the EPA Air Pollution Control Cost Manual, which is a basis for the estimation of non-EGU control cost estimates included in this TSD. This level of accuracy is consistent with either the budget or bid/tender level of cost estimation as defined by the AACE International. In addition, the accuracy of costs is also influenced by the availability of data underlying the cost estimates for individual control measures. For some control measures, we recognize that there is limited data available to generate robust cost estimates. This is reflected in the derivation of costs for some of the non-EGU NOx control measures discussed in Appendix A for this TSD.

3.3 CoST Results

The results of the CoST analysis are displayed in Table 3. In this table, we display the source groups selected by CoST, the Source Classification Codes (SCCs) included in those groups[8], the least-cost control technology for a given source group (also selected by CoST), the current estimate (in dollars per ton, using 2011 dollars) of the annualized cost per ton NOx reduced of the control technology, the current estimate of the time necessary to install the selected control technology (not including permitting time), the estimated ozone season emissions in the East from the non-EGU source group in 2017 in the absence of the installation of the selected controls, and the estimated potential ozone season reductions in the East from the non-EGU source group in 2017 assuming the selected controls could be fully installed and operational prior to the 2017 ozone season (which as discussed in more detail later, is not the case for many of the categories examined). Note that CoST does not account for installation time or time required for the permitting process. Instead it provides information on the control measures applicable to sources in the inventory, along with the cost of installation and operation of the selected measures.

[8] The CoST results do not indicate applicability of the recommended control technology to all sources in the source group but only to the specific SCCs for which control technologies are applicable. For example, for the cement kilns source group, BSI is applicable only for the types of cement kilns covered by the listed SCCs.

Table 3: CoST Results: Non-EGU Source Groups with NOx Reductions

Non-EGU Source Group	SCCs	Control Technology Recommended by CoST	Current estimate of NOx $/ton, CoST (2011 $)	Time to install[9] [10](excluding permitting, reporting preparation, programmatic and administrative considerations[11])	2017[12] NOx Emissions (37 States + DC), OS tons, CoST	2017 Potential Reductions[13] (37 States + DC), OS tons, CoST
Cement Kilns	30500622 (preheater kiln), 30500623 (preheater/precalciner); 39000201 (kiln/dryer); 39000288 (kiln in process coal)	Biosolid Injection Technology (BSI)	$410	Uncertain	24,760	4,207
Cement Mfg (dry)	30500606 Industrial Processes, Mineral Products, Cement Manufacturing (Dry Process), Kilns	Selective Non-Catalytic Reduction (SNCR)	$1,255	42-51 weeks	13,006	6,501
Cement Mfg (wet)	30500706 Industrial processes, mineral products, Cement Manufacturing (Wet Process), Kilns	Mid-Kiln Firing	$73	5-7 months	7,971	2,287

[9] Time to install is not an output of CoST, but are rather estimates determined by EPA based on research from a variety of sources. See "Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources," Institute of Clean Air Companies, December 2006 (all sources except cement kilns and RICE), "Cement Kilns Technical Support Document for the NOx FIP," EPA, January 2001 (cement kilns), and "Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry," Innovative Environmental Solutions Inc., July 2014 (prepared for the INGAA Foundation).

[10] In general, for control retrofits to non-EGU sectors, it appears that the full sector-wide compliance time is uncertain, but is longer than the installation time shown above for a typical unit. We have insufficient information on capacity and experience within the OEM suppliers and major engineering firms supply chain to offer conclusions on their availability to execute the project work for non-EGU sectors.

[11] Non-EGUs of any type – boiler or turbine – that are not currently required to monitor and report in accordance with 40 CFR Part 75 and/or not currently participating in the existing CSAPR program will require additional time relative to EGUs that are currently equipped with Part 75 monitoring and reporting and/or participating in the current CSAPR program. Installation of NOx monitors for the reporting of NOx mass requires the construction of platforms, CEM shelters, procurement of equipment, certification testing, and electronic data reporting programming of a data handling system. These added timing considerations for infrastructure on the non-EGU sources combined with the additional programmatic adoption measures necessary make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources.

[12] Emissions and potential reductions for Gas Turbines ($163/ton grouping), Cement Kiln/Dryer (Bituminous Coal) ($942/ton grouping), Coal Cleaning – Thermal Dryer (2), Spreader Strokers, Petroleum Refinery Process Heaters, Incinerators, Boilers & Process Heaters, Gas-Fired Process Heaters, Coal Boilers, By-Product Coke Manufacturing, ICI Boilers – Residual Oil, Ammonia Production, Glass Manufacturing, ICI Boilers, Iron & Steel - In-Process Combustion - Bituminous Coal, Industrial Processes Miscellaneous, Catalytic Cracking, Process Heaters, & Coke Ovens, Petroleum Refinery Gas-Fired Process Heaters, Glass Manufacturing – Pressed, Glass Manufacturing – Container, Petroleum Refinery Gas-Fired Process Heaters, and RICE source groups were calculated for 2018, however they are likely to be virtually identical to projections for 2017. Non-EGU source groups with projected aggregate 2017 NOx emissions below 100 OS tons are excluded from this table.

[13] Potential reductions assume fully implemented controls by the start of the 2017 ozone season.

Coal Cleaning – Thermal Dryer (1)	30502508 Construction Sand & Gravel, Dryer; 30501001 Industrial Processes, Mineral Products, Coal Mining, Cleaning, and Material Handling, Fluidized Bed Reactor	Low NOx Burner (LNB)	$1,125	6-8 months	503	165
Coal Cleaning – Thermal Dryer (2)	30501001 Industrial Processes, Mineral Products, Coal Mining, Cleaning, and Material Handling, Fluidized Bed Reactor	Low NOx Burner (LNB)	$1,640	6-8 months	154	63
Cement Kiln/Dryer (Bituminous Coal)	39000201 Industrial Processes, In-process Fuel Use, Bituminous Coal, Cement Kiln/Dryer (Bituminous Coal)	SNCR	$942	42-51 weeks	520	260
Iron and Steel Mills - Reheating	30300934 (303015) Primary Metal Production: Steel; 30300933	Low NOx Burner (LNB) & Flue Gas Recirculation (FGR)	$620	6-8 months	1,064	664
Steel Production	30490033 Industrial Processes, Secondary Metal Production, Fuel Fired Equipment, Natural Gas: Furnaces; 30400704 Industrial Processes, Secondary Metal Production, Steel Foundries, Heat Treating Furnace	Low NOx Burner (LNB)	$928	6-8 months	281	141
Nitric Acid Mfg	30101301 Chemical Manufacturing, Nitric Acid, Absorber Tail Gas (Pre-1970 Facilities); 30101302 Chemical Manufacturing, Nitric Acid, Absorber Tail Gas (Post-1970 Facilities)	NSCR	$900	6-14 weeks	1,290	724
Petroleum Refinery Process Heaters	30600106 Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	SCR-95%	$940-$1101	28-58 weeks	179	177
Gas Turbines	20200201 Natural Gas, Turbine; 20200203 Natural Gas, Turbine: Cogeneration; 20300202 Natural Gas, Turbine	Low NOx Burner (LNB)	$163	12 months	945	793
Gas Turbines	20200201 Natural Gas, Turbine; 20200203 Natural Gas, Turbine: Cogeneration; 20300202 Natural Gas, Turbine; 20300203 Natural Gas, Turbine: Cogeneration	Low NOx Burner (LNB)	$800	6-8 months	16,036	4,713
Natural Gas RICE Pipeline Compressors	20200202 Internal Combustion Engines, Industrial, Natural Gas, Reciprocating	Adjust Air to Fuel Ratio and Ignition Retard	$249	Uncertain	10,099	2,958

Natural Gas RICE Miscellaneous	20100202 Internal Combustion Engines, Electric Generation, Natural Gas, Reciprocating; 20200202 Internal Combustion Engines, Industrial, Natural Gas, Reciprocating; 20200204, Internal Combustion Engines, Industrial, Natural Gas, Reciprocating: Cogeneration; 20300201, Internal Combustion Engines, Commercial/Institutional, Natural Gas, Reciprocating	Adjust Air to Fuel Ratio and Ignition Retard	$447	Uncertain	27,600	8,085
Natural Gas RICE Pipeline Compressors, Rich Burn	20200253 Internal Combustion Engines, Industrial, Natural Gas, 4-cycle Rich Burn	NSCR	$517	Uncertain	11,758	10,571
Natural Gas RICE Pipeline Compressors, Lean Burn / Clean Burn	20200252 Internal Combustion Engines, Industrial, Natural Gas, 2-cycle Lean Burn; 20200254 Internal Combustion Engines, Industrial, Natural Gas, 4-cycle Lean Burn; 20200255 Internal Combustion Engines, Industrial, Natural Gas, 2-cycle Clean Burn; 20200256 Internal Combustion Engines, Industrial, Natural Gas, 4-cycle Clean Burn	Low Emission Combustion (LEC)	$649	Uncertain	47,321	41,169
Diesel / Dual Fuel RICE	20200401 Internal Combustion Engines, Industrial, Large Bore Engine, Diesel; 20200402 Internal Combustion Engines, Industrial, Large Bore Engine, Dual Fuel (Oil/Gas)	Ignition Retard	$1,255	Uncertain	865	216
Catalytic Cracking (1)	30600201 Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Fluid Catalytic Cracking Unit	Low NOx Burner (LNB) & Flue Gas Recirculation (FGR)	$1,375	6-8 months	255	140
Spreader Strokers	10100204 External Combustion Boilers, Electric Generation, Bituminous/Subbituminous Coal, Spreader Stroker (Bituminous Coal)	SNCR	$1,390	42-51 weeks	394	158
Petroleum Refinery Process Heaters	30600106 Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	SCR-95%	$1,406-$1,501	28-58 weeks	161	157

Incinerators	50200102, 50200103, 50200104, 50200504, 30190013, 30190014, 50300101, 50300106, 50300112, 50300113, 50300501, 50300503, 50300504, 50300599, 50100101, 50100102, 50100103, 50100506, 50100515, 50100516, 39990024 Incineration	SNCR	$1,842	42-51 weeks	6,556	2,950
Boilers & Process Heaters	10200203, 10200217, 10300216, 10200204, 10200205, 10300207, 10300209, 10200799 External Combustion Boilers; 30190002, 30600103 Industrial Process Heaters	SCR	$2,235	28-58 weeks	13,146	10,358
Natural Gas RICE Electric Generation	20100206 Internal Combustion Engines, Electric Generation, Natural Gas, Reciprocating: Evaporative Losses (Fuel Delivery System)	Adjust Air to Fuel Ratio and Ignition Retard	$2,347	Uncertain	107	32
Catalytic Cracking (2)	30600201 Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Fluid Catalytic Cracking Unit; 30600202 Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Catalyst Handling System	Low NOx Burner (LNB) & Flue Gas Recirculation (FGR)	$2,369	6-8 months	274	97
Gas-Fired Process Heaters (1)	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas-fired	SCR-95%	$2,376	28-58 weeks	211	204
Coal Boilers	10200206, 10200224, 10200225, 10300102, 10300208, 10300224, 10300225	SNCR	$2,413	42-51 weeks	1099	495
Gas-Fired Process Heaters (2)	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas Fired	Ultra-Low NOx Burners	$2,419-$2,638	6-8 months	137	64
By-Product Coke Manufacturing	30300306 Industrial Processes, Primary Metal Production, By-Product Coke Manufacturing, Oven Underfiring	SNCR	$2,673	42-51 weeks	2,366	1,420
ICI Boilers – Residual Oil	10200401, 10200402, 10200404, 10300401, 10300402 External Combustion Boilers, Residual Oil	LNB & SNCR	$2,850	6-8 months	991	689
Ammonia Production	30100306 Industrial Processes, Chemical Manufacturing, Ammonia Production, Primary Reformer: Natural Gas Fired	SCR	$2,896	28-58 weeks	2,508	2,257
Glass Manufacturing - Flat	30501403 Industrial Processes, Mineral Products, Glass Manufacture, Flat Glass: Melting Furnace	OXY-Firing	$3,097	Uncertain	9,721	7,880

ICI Boilers	10200201, 10200202, 10200212, 10300205, 10200501, 10200504, 10200601, 10200602, 10200603, 10200604, 10201401, 10300601, 10300602, 10200701, 10200704, 10200707, 10201402 External Combustion Boilers	Low NOx Burner & SCR	$3,456	6-8 months (LNB) 28-58 weeks (SCR)	31,005	28,204
Iron & Steel - In-Process Combustion - Bituminous Coal	30300819, 30300824, 30300913, 30300914, 30301522 Industrial Processes, Primary Metal Production	SCR	$3,705	28-58 weeks	829	746
Diesel RICE Miscellaneous	20100102 Internal Combustion Engines, Electric Generation, Distillate Oil (Diesel), Reciprocating; 20100107 Internal Combustion Engines, Electric Generation, Distillate Oil (Diesel), Reciprocating: Exhaust; 20200102 Internal Combustion Engines, Industrial, Distillate Oil (Diesel), Reciprocating; 20200106 Internal Combustion Engines, Industrial, Distillate Oil (Diesel), Reciprocating: Evaporative Losses (Fuel Storage and Delivery System); 20200107 Internal Combustion Engines, Industrial, Distillate Oil (Diesel), Reciprocating: Exhaust; 20300101 Internal Combustion Engines, Commercial/Institutional, Distillate Oil (Diesel), Reciprocating; 20400403 Internal Combustion Engines, Engine Testing, Reciprocating Engine, Distillate Oil	SCR	$3,814	28-58 weeks	1,091	869
Catalytic Cracking, Process Heaters, & Coke Ovens	30600201, 30390004, 39000701, 39000702, 39000797	LNB & FGR	$5,199	6-8 months	1,989	1,094
Petroleum Refinery Gas-Fired Process Heaters (3)	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas-fired, 30600106 Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	SCR-95%	$8,885-$9,140	28-58 weeks	370	316
Glass Manufacturing - Pressed	30501404 Industrial Processes, Mineral Products, Glass Manufacture, Pressed and Blown Glass: Melting Furnace	OXY-Firing	$6,356	Uncertain	1,001	851

Petroleum Refinery Gas-Fired Process Heaters (2)	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas-fired, 30600106 Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	SCR-95%	$7,533-$8,120	28-58 weeks	362	304
Industrial Processes Miscellaneous	30600201 Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Fluid Catalytic Cracking Unit; 39000701 Industrial Processes, In-process Fuel Use, Process Gas, Coke Oven or Blast Furnace	LNB & FGR	$4,026	6-8 months	871	479
Glass Manufacturing - Container	30501402 Industrial Processes, Mineral Products, Glass Manufacture, Container Glass: Melting Furnace	OXY-Firing	$7,481	Uncertain	3,107	2,628
Petroleum Refinery Gas-Fired Process Heaters (1)	30600104 Industrial Processes, Petroleum Industry, Process Heaters, Gas-fired; 30600106 Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	SCR-95%	$5,609-$5,884	28-58 weeks	372	338
Taconite Ore Processing	30302351, 30302352, 30302359 Industrial Processes, Primary Metal Production, Taconite Ore Processing, Induration	SCR	$6,449	28-58 weeks	1,188	991
Diesel RICE Electric Generation	20200102 Internal Combustion Engines, Electric Generation, Distillate Oil (Diesel), Reciprocating	SCR	$1,499	28-58 weeks	778	622

3.4 Discussion of Non-EGU Source Groups

The below discussion utilizes the information in Table 3 in order to assess whether significant aggregate NOx mitigation is achievable from non-EGU sources by the 2017 ozone season.

It is clear that a number of source categories have been identified by CoST that have the potential for non-EGU stationary source emissions reductions. There are some notable source categories below $10,000 per ton that have the potential for substantial non-EGU stationary source emissions reductions. However, for the purposes of this analysis, the EPA did not further examine control options above $3,300 per ton. This is consistent with the range we analyzed for EGUs in this proposal, and is also consistent with what the EPA has identified in previous transport rules as highly cost-effective, including the NOx SIP call.[14] Again, this was done because the objective of this analysis is to characterize whether significant aggregate NOx mitigation is achievable from non-EGU sources by the 2017 ozone season, so we focused the search on categories with highly cost-effective technologies. This focus excludes several source groups with high reduction potential, including as SCR & LNB from ICI boilers, LNB & FGR on Catalytic Cracking, Process Heaters, & Coke Ovens, and OXY-Firing on Pressed and Container Glass Manufacturing, because reductions from those source groups are not available for $3,300 per ton or less.

At a cost level of $3,300 per ton or less, there are a number of remaining source groups with substantial reduction potential. However the table also identifies several source groups whose reduction potential is not significant, and which EPA did not weigh heavily in assessing the aggregate non-EGU NOx reduction potential. This is because the aggregate potential reductions from these “insignificant” source groups is small. These “insignificant” source groups comprise those with many small sources, as well those containing a limited number of larger sources; for either of these types of groups, potential aggregate emission reductions are small relative to reductions available from other source categories. The EPA does not believe that small sources have significant potential in the aggregate because most small sources emit less than 100 tons of NOx per year. (It is worth noting that small sources account for a significant percentage of the total number of non-EGU point sources. Please see Appendix A/B for more information on the number of sources within certain states.) The EPA therefore excludes from the focus of this analysis these insignificant source groups, namely, those with aggregate potential reductions of 1,000 tons per year or less (which represents less than 0.1 percent of the anthropogenic ozone season inventory).

The EPA will now focus on the several source groups with significant cost-effective reductions identified in Table 3. These source groups include cement kilns, two types of cement manufacturing (dry and wet), gas turbines, four separate groups of natural gas RICE, incinerators, boilers & process heaters, by-product coke manufacturing, ammonia production, and flat glass manufacturing. These remaining source groups are listed below with their control technologies, estimated control costs, and estimated installation time.

[14] $3,300 per ton represents the $2,000 per ton value (in 1990 dollars) used in the NOx SIP call, adjusted to the 2011 dollars used throughout this proposal.

These groups have been organized into 7 categories for clarity, based on either common control technologies (categories 1 through 6) or similarity of source groups (category 7).

Category 1

Cement Mfg (dry)	SNCR	$1,255	42-51 weeks
Incinerators	SNCR	$1,842	42-51 weeks
By-Product Coke Manufacturing	SNCR	$2,673	42-51 weeks

Category 2

Cement Kilns	Biosolid Injection Technology (BSI)	$410	Uncertain

Category 3

Gas Turbines	Low NOx Burner (LNB)	$800	6-8 months

Category 4

Cement Mfg (wet)	Mid-Kiln Firing	$73	5-7 months

Category 5

Boilers & Process Heaters	SCR	$2,235	28-58 weeks
Ammonia Production	SCR	$2,896	28-58 weeks

Category 6

Glass Manufacturing - Flat	OXY-Firing	$3,097	Uncertain

Category 7

Gas RICE Pipeline Compressors	Adjust AFR and Ignition Retard	$249	Uncertain
Gas RICE Miscellaneous	Adjust AFR and Ignition Retard	$447	Uncertain
Gas RICE Pipeline Compressors, Rich Burn	NSCR	$517	Uncertain
Gas RICE Pipeline Compressors, Lean/Clean Burn	Low Emission Combustion (LEC)	$649	Uncertain

The EPA makes the following observations about the potential reductions from these significant cost-effective categories.

The source groups listed in Category 1 would utilize SNCR as the recommended control technology. The time necessary to install SNCR equipment is generally well known. A typical installation timeline of 42-51 weeks is generally needed to complete an SNCR project going from the bid evaluation through startup. Based on this fact alone (which does not consider additional time likely necessary for permitting or installation of monitoring equipment), the ability for SNCR technology to be installed and operational in time for the 2017 ozone season seems very unlikely.

The source group listed in Category 2 contains a specific source of uncertainty in regards to biosolid injection technology (BSI). Due in large part to the lack of widespread use of this control technology, research performed by the EPA has been unable to uncover any reliable information on the time required to install the necessary BSI equipment on cement kilns. Compliance timing with regard to biosolid injection technology should therefore be considered extremely uncertain. Based on this fact alone (and aside from additional time likely necessary for permitting or installation of monitoring equipment), the ability for this technology to be installed and operational at all facilities in this category in time for the 2017 ozone season is unknown.

The source group listed in Category 3 would utilize LNB as the recommended control technology, with a necessary installation time of approximately 6-8 months. Some of the LNB combustion control technology identified for non-EGU sources reflects a different technology that may have different timing considerations than that considered for EGU boilers. For instance, LNB at non-EGU combustion turbines in this assessment refers to "dry low-NOx burners" (DLNB) which, in addition to the usual diffusion burner, typically also include provisions to "premix" natural gas and combustion air prior to combustion. In spite of the similarity in naming, this is a different technology than the LNB technology examined and assumed for reductions at EGU boilers. Therefore, the same timing assumptions assumed and demonstrated on the EGU side are not necessarily applicable to combustion control technology for non-EGU sources. Moreover, non-EGUs of any type – boiler or turbine – that are not currently required to monitor and report in accordance with 40 CFR Part 75 will require additional time relative to EGUs that are currently equipped with Part 75 monitoring and reporting (such as those EGUs covered under federal transport rulemakings and this one). Installation of NOx monitors for the reporting of NOx mass requires the construction of platforms, CEM shelters, procurement of equipment, certification testing, and electronic data reporting programming of a data handling system. These added timing considerations on the non-EGU sources make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources.

The source group listed in Category 4 would utilize mid-kiln firing as the recommended control technology. A fairly well-known aspect is the time necessary to install this equipment; typically, 5-7 months is needed to complete a mid-kiln firing project going from the bid evaluation through startup. However, the above-discussed issues regarding monitoring and reporting of NOx mass on non-EGU sources that currently lack such monitoring equipment make installation of controls by the 2017 timeframe proposed in this rule less likely and more uncertain for industrial sources such as those in the cement manufacturing (wet) source group.

The source groups listed in Category 5 would utilize SCR as the recommended control technology, with an installation time of 28-58 weeks for SCR (dependent on exhaust gas flow rates; larger systems require longer installation times). Based on the installation time frame alone (which does not consider additional time likely necessary for permitting or installation of monitoring equipment), the ability for SCR technology to be installed and operational in time for the 2017 ozone season seems unlikely. In addition to this uncertainty, the above-discussed issues regarding monitoring and reporting of NOx mass on non-EGU sources that currently lack such monitoring equipment make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources such as those in Category 5 source groups.

The source group listed in Category 6 would utilize OXY-Firing as the recommended control technology, with an uncertain necessary installation. A specific source of uncertainty with regard to the estimated installation time of this control technology is that OXY-Firing is generally installed only at the time of a furnace rebuild, which rebuilds may occur at infrequent intervals of a decade or more.[15] In addition to this uncertainty, the above-discussed issues regarding monitoring and reporting of NOx mass on non-EGU sources that currently lack such monitoring equipment make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources such as those in Category 6 source group.

Finally, the source groups listed in Category 7 are all RICE. While some of the recommended control technologies may involve installation timelines that are relatively short on a per-engine basis, there is substantial uncertainty in large-scale installation over numerous sources. References indicate that implementation of NOx controls of any type on a large number of RICE will require significant lead time to train and develop resources to implement emission reduction projects; market demand could significantly exceed the available resource base of skilled professionals.[16] Additionally, in order not to disrupt pipeline capacity, engine outages must be staggered and scheduled during periods of low system demands for those engines involved in natural gas pipelines (as is the case with 3 of the 4 RICE source groups with significant cost-effective reductions). In addition to this uncertainty, the above-discussed issues regarding monitoring and reporting of NOx mass on non-EGU sources that currently lack such monitoring equipment make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources such as RICE.

4 Conclusion

The above preliminary analysis performed by the EPA indicates that uncertainty exists regarding whether significant aggregate NOx mitigation is achievable from non-EGU point sources by the 2017 ozone season. Reducing this uncertainty requires further understanding of potentially available control measures that could have annualized costs of $3,300 per ton or less. In addition, further implementation of the recommendations in the Appendices to this TSD would also reduce our uncertainty regarding the control measures included in future non-EGU NOx control strategy efforts.

While a number of source groups with control options were identified, the EPA did not further examine control options above $3,300 per ton, consistent with the range analyzed for EGUs in this proposal and with what the EPA has identified in previous transport rules as highly cost-effective. At a cost level of $3,300 per ton or less, a number of source groups

[15] See Appendix B.
[16] "Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry," Innovative Environmental Solutions Inc., July 2014.

remained, however the EPA believes several of these source groups are not significant. Of the remaining source groups, a variety of considerations indicated the ability for control technology to be installed and operational in time for the 2017 ozone season seemed unlikely, with an overarching consideration being that non-EGUs of any type that are not currently required to monitor and report in accordance with 40 CFR Part 75 will require additional time relative to EGUs that are currently equipped with Part 75 monitoring and reporting. These added timing considerations on the non-EGU sources make installation of controls by the 2017 timeframe established in this rule less likely and more uncertain for industrial sources.

With all of these factors being considered, the limited available information points to an apparent scarcity of non-EGU reductions that could be accomplished by the beginning of the 2017 ozone season. As noted in the proposed rule, this conclusion has led EPA to focus the current proposed FIPs on EGU reductions. The proposal acknowledges that this may not be the full remedy that is ultimately be needed to eliminate an upwind state's significant contribution to nonattainment or interference with maintenance of the 2008 ozone NAAQS (or, for that matter, the 2015 ozone NAAQS). Emissions reductions from the non-EGU categories discussed above may be necessary, though on a longer timeframe than the 2017 compliance deadline being proposed in this rulemaking. EPA intends to explore this question further in the near future and welcomes comment on any of the information in this TSD to assist with that effort.

May 2014

Update of NOx Control Measure Data in the CoST Control Measure Database for Four Industrial Source Categories: Ammonia Reformers, NonEGU Combustion Turbines, Glass Manufacturing, and Lean Burn Reciprocating Internal Combustion Engines

Final Report

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October 2014

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SECTION 1
INTRODUCTION

The U.S. Environmental Protection Agency (EPA) Health and Environmental Impacts Division (HEID) has developed the Control Strategy Tool (CoST) to support national- and regional-scale multipollutant air quality modeling analyses. CoST allows users to estimate the emissions reductions and costs associated with future-year emission control strategies, and then to generate emission inventories that reflect the effects of applying the control strategies. The tool uses EPA HEID's Control Measures Database (CMDB) to develop control strategies and provides a user interface to that database. The CMDB is a relational database that contains information on an extensive set of control measures for point sources, nonpoint sources, and mobile sources. Information contained in the database includes descriptions of the measures, control efficiencies for the pollutants affected, costs of control, and the types of sources or processes to which the control measures can be applied. The database includes robust cost equations to determine engineering costs for some control measures that take into account how control costs vary with respect to variables for the source such as unit size or flow rate. The database also includes simple cost factors for all source types in terms of dollars per ton of pollutant reduced that can be used to calculate the cost of the control measure if the applicable source variable data are unavailable or no equation has been developed.

This report presents the results of an effort to review and enhance the CMDB with new and/or updated NOx control measure data for the following four industrial source categories: ammonia reformers, combustion turbines (nonEGU), glass manufacturing, and lean burn reciprocating internal combustion engines. Section 2 of this report describes the procedures used to locate more recent data than that currently in the CMDB for control measures applicable to ammonia reformers. Section 2 also identifies the source of the new data, describes any modifications to the assumptions or procedures in the referenced analyses needed to make the results consistent with results for other control measures in the database (such as operating hours for determination of total annual costs), and describes the specific recommended changes or additions to the database. Sections 3 through 5 of this report provide similar details for combustion turbines, glass manufacturing, and lean burn reciprocating internal combustion engines, respectively. Appendix A presents all of the records for ammonia reformer control measures in each of the CMDB tables showing their content after making the recommended revisions described in the report. Appendixes B through D provide comparable tables for the combustion turbine, glass manufacturing, and lean burn reciprocating internal combustion engine (RICE) source categories, respectively. Appendix E provides answers to questions on lean-burn RICE NOx emissions and available control measures. It should be noted that these revisions and updates will improve the accuracy and quality of NOx non-EGU control strategy and cost analyses for EPA rulemakings.

SECTION 2
AMMONIA REFORMERS SECTOR

The control measures database includes the following NO_X emissions control measures for ammonia reformers:

- Oxygen trim and water injection,
- Low NO_X burners and flue gas recirculation,
- Selective non-catalytic reduction (SNCR),
- Selective catalytic reduction (SCR), and
- Low NO_X burners.

In order to update the existing control measures database, a literature search was conducted using the following terms:

- reformer
- cost
- "NO_X" or "nitrogen oxide"
- "Low NO_X burner" or "LNB"
- "Flue gas recirculation" or "FGR"
- oxygen trim
- water injection
- "Selective catalytic reduction" or "SCR"
- "Selective non catalytic reduction" or "SNCR"
- emission reduction
- control efficiency

Due to the use of SCR and SNCR to control NO_X emissions and the fact that ammonia is used in the operation of SCR and SNCR, the literature search resulted in NO_X reductions on processes other than ammonia production.

In order to focus on ammonia production, a focused internet search for operating permits, BACT analyses, and NO_X controls was conducted using the 22 ammonia production facilities in the United States.

As a result of the following facts, most of the internet search results included NO_X reductions from the production of nitric acid production instead of ammonia production:

- The NO_X emissions from nitric acid production are covered by a New Source Performance Standard (NSPS) codified as Subpart G and Subpart Ga of Part 60.
- Nitric acid facilities covered by the NSPS are required to install NO_X continuous emission monitoring systems (CEMS).
- Many nitric acid facilities use SCR to control NO_X emissions.
- Many ammonia production facilities are co-located with nitric acid production facilities.

The internet search resulted in one new NO_X reduction project, which was the result of a voluntary agreement between Terra Nitrogen and the Indian Nations Council of Governments to install "ultra-low NO_X burner technology to an existing ammonia reformer [and] reduce the unit's NO_X emissions by approximately 60% at a projected capital cost of two million dollars." The existing ammonia reformer is located at Terra Nitrogen, L.P., Verdigris Plant in Claremore, Oklahoma.

Based on information known to EPA and collected for this report, Low NO_X burner technologies are known and demonstrated control techniques for ammonia reformers.

The following sections outline the deletions, additions, changes, and other comments recommended for the CMDB in relation to NO_X emissions from ammonia reformers.

2.1 Recommended Deletions

No deletions are recommended.

2.2 Recommended Additions

The only addition to the CMDB is to add the following reference: *Tulsa Metropolitan Area 8-Hour Ozone Flex Plan: 2008 8-O_3 Flex Program*. Prepared by Indian Nations Council of Governments (INCOG), 201 W. 5th Street, Suite 600, Tulsa, OK 74103. March 6, 2008. http://www.epa.gov/ozoneadvance/pdfs/Flex-Tulsa.pdf.

This addition is shown in Appendix A as Table A-1.

2.3 Recommended Changes

Updates to costs and Efficiencies.

Changes to one record (LNB applied to large source types) are recommended to reflect the new reference dated March 6, 2008.

Using the new reference and a reference already contained in the CMDB, the following assumptions were made:

- NO_X reductions of 425 tons per year[1]
- Capital cost of $2 million[1]
- Maintenance costs are 2.75% of capital costs[2]
- Equipment life of 10 years
- Interest rate of 7%
- Capital recovery factor of 0.1424.

The resulting annual costs are $339,800 and the cost effectiveness is $800 per ton of NO_X reduction (both in 2008 dollars). The capital to annual cost ratio is 5.9.

The previous entry showed a cost effectiveness of $650 per ton of NO_X reduction (in 1990 dollars) and a capital to annual cost ratio is 5.5. The changes are included in Appendix A as Table A-2 and Table A-3. Changes are indicated by red, italic text.

Updates to Source Classification Codes.

The U.S. Environmental Protection Agency (USEPA) developed the Source Classification Code (SCC) system, which assigns an eight digit code to each emission unit based on the general criteria pollutant emission point type, the major industry group, specific industry group, and specific process unit/fuel combination. The system allows similar emission points to be grouped together for analyses.

For ammonia reformers, there are seven applicable SCCs, as shown in Table 2-1.

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[1] Indian Nations Council of Governments (INCOG), 2008: Indian Nations Council of Governments (INCOG), "Tulsa Metropolitan Area 8-Hour Ozone Flex Plan: 2008 8-O3 Flex Program," March 6, 2008. Downloaded from http://www.epa.gov/ozoneadvance/pdfs/Flex-Tulsa.pdf.

[2] U.S. Environmental Protection Agency. Alternative Control Techniques Document— NO_X Emissions from Process Heaters (Revised), document EPA-453/R-93-034, dated September 1993.

Table 2-1. Applicable SCCs for the Ammonia Production Industry

SCC	SCC 1	SCC3	SCC6	SCC8
30100305	Industrial Processes	Chemical Manufacturing	Ammonia Production	Feedstock Desulfurization
30100306	Industrial Processes	Chemical Manufacturing	Ammonia Production	Primary Reformer: Natural Gas Fired
30100307	Industrial Processes	Chemical Manufacturing	Ammonia Production	Primary Reformer: Oil Fired
30100308	Industrial Processes	Chemical Manufacturing	Ammonia Production	Carbon Dioxide Regenerator
30100309	Industrial Processes	Chemical Manufacturing	Ammonia Production	Condensate Stripper
30100310	Industrial Processes	Chemical Manufacturing	Ammonia Production	Storage and Loading Tanks
30100399	Industrial Processes	Chemical Manufacturing	Ammonia Production	Other Not Classified

In an analysis of NO_X emissions for the Ozone Transport Region in 2011, four of the SCCs in Table 2-1 were identified. These SCCs are 30100306, 30100307, 30100310, and 30100399. Only SCCs 30100306 and 30100307 are associated with ammonia reformer NO_X controls in the current CMDB.

The known control techniques for ammonia reformers are typically used for point emission sources, such as stacks. Emissions from SCC 30100310 are not typically vented, so capture and control of these emissions is likely not feasible. Therefore, no changes related to SCC 30100310 are recommended for the CMDB.

For the purposes of this analysis, SCC 30100399 is assumed to include combustion emissions from gaseous fuels other than natural gas. Therefore, all control techniques that are applicable to natural gas fired ammonia reformers are assumed to also apply to SCC 30100399. Also, the cost to control NO_X emissions from gaseous fuels is assumed to be comparable to the cost to control NO_X emissions from natural gas. Therefore, the costs related to those control techniques are assumed to apply to SCC 30100399.

The applicable SCC from Table 2-1 was added to the Description field for each control technique in Table A-2 of Appendix A. SCC 30100306 was already included in the table; SCCs 30100305, 30100307, and 30100399 were added, where appropriate. Changes are indicated by red text.

2.4 Other Comments

Control measures used by ICI boilers. Review of NO_X control measures used for boilers was not included in this analysis. However, many of the SCR costs in the CMDB for natural gas fired ammonia reformers are based on SCR costs for Industrial/Commercial/Institutional (ICI) Boilers using Process Gas. No SCR costs specific to ammonia reformers were noted in the CMDB.

At a later time, it may be pertinent to review recent final ICI Boilers regulations or other sources for potential updates to the cost of SCR on ammonia reformers. The final major source NESHAP for ICI Boilers was promulgated on January 31, 2013 and the final area source NESHAP for ICI Boilers was promulgated on February 1, 2013.

Potential NO_X limits for ammonia reformers based on boiler NO_X limits. According to NO_X Reasonably Acceptable Control Technology (RACT), the states of New Jersey and New York have established emission limits for ICI Natural Gas Boilers (greater than 100 million BTU per hour) that could be applicable to natural gas ammonia reformers. These RACT limits are shown in Table 2-2.

Table 2-2. RACT NO_X Limits for ICI Natural Gas Boilers

State	Boiler Size	Limit (lb NO_X/MMBTU)	Effective Date
New Jersey[a]	>100 MMBTU	0.10	Already in effect
New York	>100 MMBTU and ≤ 250 MMBTU	0.06	7/1/14
New York	> 250 MMBTU	0.08	7/1/14

[a] The limit also applies to other indirect heat exchangers.

SECTION 3
COMBUSTION TURBINES

The CMDB includes the following NO_X emissions control measures for Combustion Turbines:

- Water injection for natural gas-fired turbines (achieves 76 percent reduction)
- Steam injection for natural gas-fired turbines (achieves 80 percent reduction)
- Low NOx Burners for natural gas-fired turbines (achieves 84 percent reduction)
- SCR on natural gas-fired turbines that also have water injection (achieves 95 percent reduction)
- SCR on natural gas-fired turbines that also have steam injection (achieves 95 percent control)
- SCR on natural gas-fired turbines that also have low NOx burners (achieves 94 percent reduction)
- Water injection for oil-fired turbines (achieves 68 percent reduction)
- SCR on oil-fired turbines that also have water injection (achieves 90 percent reduction)
- Water injection for jet fuel-fired turbines (achieves 68 percent reduction)
- SCR on jet fuel-fired turbines that also have water injection (achieves 90 percent reduction)
- Water injection for aeroderivative turbines (achieves 40 percent reduction)

All of the cost data are in 1990 dollars, except the costs of water injection for aeroderivative turbines, which are in 2005 dollars. In addition, all of the costs are based on estimated operation for 8,000 hr/yr, except the costs of water injection for aeroderivative turbines, which are for intermittently operated units. The costs in 1990 dollars are based primarily on analyses in EPA's 1993 ACT document for NOx Emissions from Stationary Gas Turbines (EPA, 1993). Capital and annual cost equations are provided for all of the controls except those for jet fuel-fired turbines and water injection for aeroderivative turbines.

Literature search. In order to update the existing CMDB, a literature search was conducted for articles and papers published since 2008. In addition, an internet search was conducted for BACT analysis reports and control technology reports prepared for federal and state agencies and RPOs. The literature search did not identify any documents with cost data, but the internet search identified the documents listed in Section 3.5 of this report.

Changes to CMDB. The following sections outline the deletions, additions, and other changes recommended for the CMDB in relation to NO_X emissions from Combustion Turbines. All cost data and calculations are in an Excel Worksheet (RTI, 2014). Copies of the CMDB tables with recommended revisions to the records for combustion turbine controls are provided in Appendix B.

The coefficient of determination (R^2) is 1.0 for many of the regression equations presented in sections 3.2 and 3.3. The R2 value is exactly 1.0 in cases where the analysis was based on only two data points; these cases are noted in the discussions for the particular control measure. In other cases, actual R2 values greater than 0.995 have been rounded to 1.0. These high values likely are due to the fact that available data for most control measures are from a single source, and those sources may have already developed a correlation and then picked specific data points from that correlation for presentation in their documentation.

3.1 Recommended Deletions

RTI recommends deleting the record for water injection for aeroderivative turbines because the estimated costs are for combustion turbines that operate on a limited and intermittent basis (i.e., peaking EGUs). In principle, data for small EGU combustion turbines would be acceptable for estimating costs of control measures for nonEGUs. However, the limited operation of peaking units is inconsistent with the assumed operating time of about 8,000 hr/yr for all of the other nonEGU combustion turbine control measures in the database. For several SCCs that are currently associated with this control measure in the CMDB we are recommending applying other existing control measures, as discussed in Section 3.3.11 of this report.

The CMDB also currently applies several gas turbine control measures to reciprocating internal combustion engine SCCs and to gas turbine SCCs for evaporative losses from fuel storage and delivery systems. We recommend deleting these applications of the gas turbine control measures, as discussed in Section 3.3.11 and Section 5.9 of this report.

3.2 Recommended Additions

There are 3 control technique additions for emerging technologies to be added to the CMDB; these additions include:

- Catalytic Combustion; Gas Turbines—Natural Gas;

- EMx and Water Injection; Gas Turbines—Natural Gas;
- EMx and Dry Low NOx Combustion; Gas Turbines—Natural Gas.

3.2.1 Catalytic Combustion; Gas Turbines—Natural Gas (NCATCGTNG)

Catalytic combustion is a flameless process that allows fuel oxidation to occur at temperatures approximately 1800°F lower than those of conventional combustors (OSEC, 1999). Lower temperatures are desirable because NOx emissions levels are strongly correlated with temperature. One design that has been commercialized is the Xonon™ combustor (now called K-Lean™). In the Xonon combustor, a small amount of fuel is burned in a low temperature pre-combustor. Additional fuel is then mixed with the air and combustion gases from the pre-combustor and passed through a catalyst module. The catalyst promotes a flameless reaction between some of the fuel and oxygen. The gases then enter a burnout zone in which the remaining fuel burns. The maximum temperature in the system is between 2300°F and 2700°F. In addition to low NOx emissions, the catalytic combustor generates very little CO emissions. (Peltier, 2003; CARB, 2004; Leposky, 2004; Kawasaki, 2010; Quackenbush, 2012)

Since 1999 at least six Xonon combustors have been installed; all are 1.4 MW units (CARB, 2004; Kawasaki, 2010; Quackenbush, 2012). Testing of four of the operating Xonon combustors has shown NOx emissions less than 3 parts per million by volume on a dry basis (ppmvd) at 15% oxygen, and permit limits range from 3 ppmvd to 20 ppmvd at 15% oxygen (CARB, 2004; Quackenbush, 2012). Several companies have conducted research into developing larger catalytic combustors and other types of designs, but no information was found indicating that such units have been commercialized (CARB, 2004; Leposky, 2004; Cybulski, 2006).

Although one type of catalytic combustor has been commercialized, we recommend considering catalytic combustion as an emerging technology in the CMDB because so few units are in operation, and they are all only one size. In addition, as of 1999, issues with catalytic combustors include the need for the air-fuel mixture to have completely uniform temperature, composition, and velocity profile to assure effective use of all the catalyst and to prevent damage to the substrate from high temperatures. Also the catalyst durability is uncertain (OSEC, 1999).

The recommended costs are based on costs presented in a report by Onsite Sycom Energy Corporation (OSEC, 1999). The only change we made to the OSEC costs was to calculate capital recovery using an interest rate of 7 percent instead of 10 percent; this change makes the capital recovery costs consistent with guidance in Circular A-4 from the Office of Management and Budget. Table 3-1 summarizes the recommended cost effectiveness and capital to annual cost ratios for implementing the catalytic combustion NOx control technology. With an outlet concentration of 3 ppmvd, catalytic combustion achieves an average reduction of 98 percent relative to uncontrolled conventional diffusion combustion.

Table 3-1. Summary of Cost Effectiveness and Supporting Data for Catalytic Combustion

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio
		Avg. ppmvd	tpy			
Small (5.2)	1999	150	<365	3	920	1.7
Small (26.3)	1999	130	>365	3	670	1.2
Large (170)	1999	210	>365	3	370	0.7

Based on regression of the data in the analysis, the best fit trend lines are represented by the following equations for the uncontrolled scenario:

$$\text{Total capital investment (1999 dollars)} = 20668 \text{ x (MMBtu/hr) } ^\wedge {}^{0.57} \quad (R^2=1.0)$$

$$\text{Total annual cost (1999 dollars)} = 4254.2 \text{ x (MMBtu/hr) } ^\wedge {}^{0.82} \quad (R^2=1.0)$$

For all but the smallest turbines, the incremental cost of catalytic combustors relative to conventional combustors is less than the incremental cost of DLN combustion versus conventional combustors. Thus, there are no incremental capital costs for catalytic combustion relative to conventional combustion. However, there are incremental annual costs because the cost of catalyst replacement is high. A best fit equation for incremental catalytic combustion total annual costs relative to a RACT baseline of DLN combustion is:

$$\text{Total annual cost (1999 dollars)} = 743.22 \text{ x (MMBtu/hr)} + 54105 \; (R^2=1.0)$$

3.2.2 EMx and Water Injection; Gas Turbines—Natural Gas (NEMXWGTNG)

Like SCR, EMx^{TM} (formerly called SCONOX^{TM}) is a post-combustion catalytic NOx reduction technology. EMx uses a precious metal catalyst and a NOx absorption/regeneration process to convert CO and NOx to CO2, H2O, and N2. NOx reacts with the potassium carbonate absorbent coating the surface of the oxidation catalyst in the EMx reactor, forming potassium nitrites and nitrates that are deposited onto the catalyst surface. Each segment, or "can," within the reactor becomes saturated with potassium nitrites and nitrates over time and must be desorbed. Regeneration is accomplished by isolating the can via stainless steel lovers and injecting hydrogen diluted with steam. Hydrogen is generated onsite with a small reformer that uses natural gas and steam as input streams. The hydrogen concentration of the reformed gas is typically 5 percent. Hydrogen and carbon dioxide react with the potassium nitrites and nitrates to form N_2 and H_2O and to regenerate the potassium carbonate for another absorption cycle. (OSEC, 1999; CARB, 2004)

At least 8 EMx systems at 6 facilities have been installed on combustion turbines with capacities up to 45 MW. Permit limits at most of these facilities have been set at 2.5 ppmvd for gas-fired operation. EPA has certified it as "demonstrated in practice" LAER-level technology that reduces NOx to less than 5 ppmvd. The operating range of the catalyst is 300 to 700°F, which means the technology is not applicable for simple cycle turbines. The vendor for the technology has indicated that these systems also reduce carbon monoxide emissions to undetectable levels (essentially 100 percent reduction), reduce volatile organic compound emissions by greater than 90 percent, and reduce fine particulate matter emissions by 30 percent (EmeraChem, 2004). Test data documenting these reductions are not available. For the purposes of the CMDB database, we recommend that this control measure be listed as an emerging technology (rather than known) because its use has been limited to only a few small turbines.

The recommended costs for EMx in the combined EMx/water injection control measure are based on costs presented in a 2008 cost estimate prepared by EmeraChem Power for the Bay Area Air Quality Management District (ECP, 2008). For the purposes of developing 2008 cost inputs for the CMDB, we made the following changes to the data and assumptions used in the ECP analysis:

- Increased the indirect cost for engineering from $200,000 to $255,000 for the 50 MW turbine. ECP's documentation indicated that this cost (as well as most of the other direct installation and indirect costs) would be the same as for an SCR system on the same turbine. The reported cost of $200,000 was inconsistent with this statement.

- Increased the contingencies cost for the 50 MW turbine from $76,486 to $244,101. This change makes the cost consistent with ECP's statement that the cost for contingencies is estimated to be equal to 5 percent of the total purchased equipment cost, excluding the cost of the precious metals in the catalyst, sales taxes, and freight.

- Added a cost for the performance loss due to back pressure from the EMx system for both turbines. ECP estimated the loss to be 0.5 percent, which is consistent with the estimate in the 1993 ACT for SCR and the estimate OSEC used in a cost analysis for SCONOx (EPA, 1993; OSEC, 1999). However, the ECP analysis did not include a corresponding dollar amount for this element.

- Changed the operating hours from 7,884 hr/yr to 8,000 hr/yr. This change also had a small effect on the annual costs for utilities.

- Added costs for natural gas to generate steam for the 50 MW turbine using the same procedures presented in the ECP analysis for the 180 MW turbine. ECP did not report the basis for the amount of steam needed for the 180 MW turbine. Therefore, we plotted the reported steam consumption versus turbine size for this unit and for two turbines identified in a CARB analysis (CARB, 2004). We calculated the quantity of steam needed for EMx on the 50 MW turbine using the regression equation from this plot. Note that the unit cost for natural gas is $9.75/1000 scf. This was a reasonable annual average cost in 2008, but it would be much too high for an analysis in 2014.

- Deleted the credit for recovery of precious metals in the spent catalyst because the cost for replacement catalyst considers only the difference between the total purchase price minus the value of the recovered material.

- Estimated the annualized cost of replacement catalyst (both the non-precious metal substrate and the precious metal coating) using the future worth factor, whereas the cost in the ECP analysis was the purchased cost divided by the 10-year replacement interval.

- Estimated the cost of annual catalyst cleaning based on the average if data reported by CARB (CARB, 2004) plus the amounts reported by ECP. Although ECP reported a slightly higher cleaning cost for the 180 MW turbine than for the 50 MW turbine, an analysis of all the cleaning data showed no correlation with turbine size. Thus, we used the average of all reported costs for both turbines.

- Revised the indirect annual cost for administrative charges. ECP estimated that these costs are the same as for an SCR system on the same turbines. We factored the cost as 2 percent of the TCI for the applicable EMx systems, which is consistent with the approach for all control devices in the EPA Control Cost Manual. This resulted in slightly higher costs.

- Increased the indirect costs for insurance, property tax, and capital recovery for both turbines because the ECP analysis excluded the precious metal costs from the TCI used in these calculations.

- Calculated capital recovery using an interest rate of 7 percent instead of 10 percent.

The capital costs for water injection in the combined EMx/water injection control measure were estimated in 1999 dollars using the regression equation for the water injection control measure (see Section 3.3.1) and then scaled to 2008 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Total annual costs for water injection were first estimated in 1999 dollars using the regression equation for the water injection control option. On average, 25 percent of these costs were estimated to be for indirect costs that are factored from the system capital cost, and the remaining 75 percent is for direct annual costs and overhead. To estimate the total annual costs for water injection in 2008, the indirect costs were scaled from the 1999 estimate using the CEPCI, and the direct annual costs and overhead were assumed to be the same as in 1999.

Table 3-2 summarizes the recommended cost effectiveness and capital to annual cost ratios for implementing the EMx plus water injection NOx control measure. With an outlet concentration of 2 ppmvd, this control measure achieves an average reduction of 99 percent relative to uncontrolled conventional diffusion combustion.

Table 3-2. Summary of Cost Effectiveness and Supporting Data for EMx Plus Water Injection

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		EMx Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of WI, $/ton NOx
		Avg ppmvd	tpy				
Large (50-180)	2008	160[a]	>365	2.0	2,760	3.1	6,810

[a]Uncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

Based on regression of the data in the analysis, the best fit trend lines are represented by the following power equations for the uncontrolled scenario (the R^2 =1.0 for both equations because there were only two data points in the analysis):

$$\text{Total capital investment (2008 dollars)} = 196928 \times (\text{MMBtu/hr})^{\wedge\ 0.68}$$

$$\text{Total annual cost (2008 dollars)} = 18747 \times (\text{MMBtu/hr})^{\wedge\ 0.86}$$

Best fit equations for incremental EMx costs relative to a RACT baseline of water injection are:

$$\text{Total capital investment (2008 dollars)} = 156349 \times (\text{MMBtu/hr})^{\wedge\ 0.68}$$

$$\text{Total annual cost (2008 dollars)} = 17252 \times (\text{MMBtu/hr})^{\wedge\ 0.80}$$

3.2.3 EMx and Dry Low NOx Combustion; Gas Turbines—Natural Gas (NEMXDGTNG)

Table 3-3 summarizes the recommended cost effectiveness and capital to annual cost ratios for implementing the EMx plus dry low NOx combustion control measure. With an outlet concentration of 2 ppmvd, this control measure achieves an average reduction of 99 percent relative to uncontrolled conventional diffusion combustion. For the same reasons noted in Section 3.2.2, we recommend that this control measure be listed as an emerging technology in the CMDB.

Table 3-3. Summary of Cost Effectiveness and Supporting Data for EMx Plus Dry Low NOx Combustion

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		EMx Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of DLN, $/ton NOx
		Avg ppmvd	tpy				
Small (4.2)	1999	134	<365	2.0	2,860	3.9	14,940
Small (23)	1999	174	>365	2.0	1,720	4.1	10,270
Large (170)	1999	210	>365	2.0	840	3.9	6,600
Large (50-180)	2008	160[a]	>365	2.0	2,050	4.1	12,390

[a]Uncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

The recommended costs for EMx in 2008 dollars for the combined EMx/dry low NOx combustion control measure are the same as in the estimate for the EMx/water injection control measure described in Section 3.2.2. The recommended costs for EMx in 1999 dollars are based on an analysis prepared by Onsite Sycom Energy Corporation (OSEC, 1999). For this analysis the only changes we made to OSEC's analysis were to reduce the operating hours from 8,400 hr/yr to 8,000 hr/yr, which slightly reduced the energy penalty and utilities costs, and we calculated the capital recovery factor using an interest rate of 7 percent instead of 10 percent. Note that the total annual costs for natural gas (or purchased steam) are considerably lower in this analysis than in the 2008 analysis because the unit cost of natural gas was considerably lower in 1999.

The recommended total capital investment and total annual cost for dry low NOx combustion in 1999 dollars for the combined EMx/dry low NOx combustion control measure are the same as in the estimate for the dry low NOx combustion control measure alone as described in Section 3.3.3. The recommended total capital investment for dry low NOx combustion in 2008 dollars was estimated in 1999 dollars using the regression equation for the water injection control measure (see Section 3.3.1) and then scaled to 2008 dollars using the CEPCI. The recommended total annual costs for dry low NOx combustion consist of capital recovery plus the cost for parts and repair; capital recovery costs in 2008 dollars were estimated by escalating the 1999 costs using the CEPCI, and annual parts and repairs costs were assumed to be the same in 2008 as in 1999.

Based on regression of the data in both the 1999 and 2008 cost analyses, the best fit trend lines are represented by the following power equations for the uncontrolled scenario (the R^2 =1.0 for the equations in 2008 dollars because there were only two data points in the analysis; R^2 for the equations in 1999 dollars round to 1.0 when only two significant figures are presented):

$$\text{Total capital investment (1999 dollars)} = 58237 \text{ x } (\text{MMBtu/hr}) \wedge {}^{0.78}$$

$$\text{Total annual cost (1999 dollars)} = 15004 \text{ x } (\text{MMBtu/hr}) \wedge {}^{0.78}$$

$$\text{Total capital investment (2008 dollars)} = 126892 \text{ x } (\text{MMBtu/hr}) \wedge {}^{0.74}$$

$$\text{Total annual cost (2008 dollars)} = 20041 \text{ x } (\text{MMBtu/hr}) \wedge {}^{0.80}$$

Best fit equations for incremental EMx costs relative to a RACT baseline of DLN combustion are:

$$\text{Total capital investment (1999 dollars)} = 65163 \text{ x } (\text{MMBtu/hr}) \wedge {}^{0.72}$$

$$\text{Total annual cost (1999 dollars)} = 13702 \text{ x } (\text{MMBtu/hr}) \wedge {}^{0.76}$$

$$\text{Total capital investment (2008 dollars)} = 156349 \text{ x } (\text{MMBtu/hr}) \wedge {}^{0.68}$$

$$\text{Total annual cost (2008 dollars)} = 17252 \text{ x } (\text{MMBtu/hr}) \wedge {}^{0.80}$$

3.3 Recommended Changes

This section presents updated cost estimates for combustion turbine control measures that are currently in the CMDB, and it describes the basis for such changes. These changes include both more recent costs for some control measures as well as minor revisions to existing estimates for other control measures. The changes affect both cost per ton values and equations.

This section also identifies applicable SCCs for the new control measures described in Section 3.2, and it identifies additional SCCs for which the control measures in this section are applicable.

3.3.1 Water Injection; Gas Turbines—Natural Gas (NWTINGTNG)

Recommended updates to the costs for water injection are based on analyses in a report prepared by OnSite Sycom Energy Corporation for the U.S. Department of Energy (OSEC, 1999). OSEC estimated costs for some of the same small turbine model sizes as in EPA's 1993 ACT document (4 MW and 23 MW). OSEC obtained water injection equipment costs in 1999 dollars. They then estimated total capital investment and total annual costs using the same procedures as in the 1993 ACT document, and they concluded that 1999 costs for water injection were essentially the same as the 1990 costs presented in the ACT document. Because the ACT analysis included a greater number of models over a wider range of sizes, RTI recommends continuing to use the cost data from the ACT analysis in the CMDB, except the cost year should be updated from 1990 to 1999. RTI also recommends the four additional changes noted below.

Our second recommendation is to split the record for small sources into two records—one for sources with uncontrolled emissions less than 365 tpy, and the other for emissions greater than 365 tpy. The 2006 AirControlNET Documentation Report indicates that small sources are turbines with design outputs up to 34.4 MW. Four model turbines in the ACT analysis have outputs below this threshold. The two turbines with uncontrolled emissions <365 tpy have an average cost effectiveness of $1,790/ton of NOx. The two turbines with uncontrolled emissions >365 tpy have an average cost effectiveness of $1,000/ton of NOx.

Our third recommendation is to revise the control efficiency for water injection from 76 percent to 72 percent. The 76 percent control level is the average reduction for all 6 model turbines in the 1993 ACT analysis. Five of those models were guaranteed to reduce NOx emissions to less than 42 ppmvd, while the sixth was guaranteed to meet 25 ppmvd. Although water injection may be more effective on some combustion turbines than others, 42 ppmvd is the generally accepted threshold. Thus, we think this threshold should be incorporated in the CMDB. The average reduction of the 5 models in the 1993 ACT analysis with an outlet concentration of 42 ppmvd was 72 percent.

Our fourth recommendation is to use a capital to annual cost ratio of 2.4 in the new record for small sources with uncontrolled emissions >365 tpy; this is the average value for the two turbines in the ACT analysis in this size range. (The capital to annual cost ratio for the small sources with uncontrolled emissions <365 tpy would remain at 3.1 because this is the average value for the two turbines in this size range; it is not clear why this value was applied for all small sources in the current version of the CMDB.) The total annual costs in this calculation are based on using a 7 percent interest rate in the calculation of capital recovery, instead of the 10 percent value in the 1993 ACT. Even if capital recovery was estimated using the 10 percent interest rate, it is not clear how the 3.1 value was developed.

Our fifth recommendation is to revise the constants in the CMDB table of equations for estimating capital and annual costs. Based on regression of the data in the 1993 ACT, the best fit trend lines are represented by the following revised power equations for both uncontrolled and RACT baseline scenarios:

$$\text{Total capital investment (1999 dollars)} = 27665 \text{ x } (\text{MMBtu/hr}) \wedge {}^{0.69} \ (R^2 = 0.97)$$

$$\text{Total annual cost (1999 dollars)} = 3700.2 \text{ x } (\text{MMBtu/hr}) \wedge {}^{0.95} \ (R^2 = 0.95)$$

3.3.2 Steam Injection; Gas Turbines—Natural Gas (NSTINGTNG)

The only available information on the cost of steam injection was in the 1999 report from Onsite Sycom Energy Corporation (OSEC, 1999). OSEC discussed steam injection only in the context of large GE Frame 7F turbines (170 MW). They noted that only the first such model, operational in 1990 when the ACT analysis was being conducted, was equipped with steam injection. All subsequent units (at least through 1999) were equipped with DLN combustion technology.

Because the limited available information suggests that steam injection costs, like water injection costs, were essentially the same in 1999 as in 1990, we recommend continuing to base the steam injection costs on the results in the 1993 ACT, but update the cost year from 1990 to 1999. In addition, as for water injection, we recommend splitting the one record for small sources into two records—one for sources with uncontrolled NOx emissions <365 tpy, and the other for uncontrolled NOx emissions >365 tpy. This split results in average cost effectiveness values of $1,690/ton of NOx for the small sources with uncontrolled NOx emissions <365 tons/yr and $820/ton of NOx for the small sources with uncontrolled NOx emissions >365 tons/yr. The capital cost to annual cost ratios also are slightly less than the current values in the CMDB.

Based on regression of the data in the 1993 ACT, the best fit trend lines are represented by the following revised power equations for both uncontrolled and RACT baseline scenarios:

$$\text{Total capital investment (1999 dollars)} = 43092 \times (\text{MMBtu/hr})^{0.82} \quad (R^2=0.95)$$

$$\text{Total annual cost (1999 dollars)} = 7282 \times (\text{MMBtu/hr})^{0.76} \quad (R^2=0.96)$$

3.3.3 Dry Low NOx Combustion; Gas Turbines—Natural Gas (NDLNCGTNG)

Dry low NOx (DLN) combustion technology premixes air and a lean fuel mixture that significantly reduces peak flame temperature and thermal NOx formation. In some cases, this can be accomplished by using low NOx burners, but in other cases, the combustor design itself differs as well as the burner design. For example, the DLN combustor volume is typically twice that of a conventional combustor (OSEC, 1999). Therefore, we recommend revising the current control technology name in the CMDB from “Low NOx Burners” to “Dry Low NOx Combustion.” In addition, the CM abbreviation should be changed from NLNBUGTNG to NDLNCGTNG.

Recommended updates to the costs for DLN Combustion are based on analyses in a report prepared by Onsite Sycom Energy Corporation for the U.S. Department of Energy (OSEC, 1999). OSEC estimated costs for some of the six turbines with design outputs ranging from 4 MW to 169 MW.

OSEC obtained installed equipment costs and annual repair costs in 1999 dollars from three turbine manufacturers, but there are some uncertainties in the data. Although the reported tabular summary indicates the equipment costs are incremental relative to the cost of a conventional combustor, the text of the report states that the costs for 169 MW turbines are the total cost to replace a conventional combustor (which may explain why the regression equation for the capital costs is linear rather than a power function). Annual costs for parts and repair for some of the turbines were proprietary for two of the small turbines and thus could not be reported. As a result, the annual costs for those turbines are biased low. In addition, because parts and repair costs were unavailable for the 169 MW turbine, OSEC assumed these costs could be represented by the costs for the 23 MW turbine.

The only change we made to the assumptions and data reported by OSEC was to calculate capital recovery using an interest rate of 7 percent instead of 10 percent.

Table 3-4 summarizes the recommended new cost effectiveness and capital to annual cost ratios for implementing the DLN combustion NOx control technology. In addition to changing these costs in the CMDB, we also recommend changing the control efficiency for DLN combustion applied to small sources from 68 percent to 84 percent. The 84 percent level is currently used for large sources, and it is consistent with the efficiency for DLN combustion (or low NOx burners) in the 1993 ACT. It appears the 68 percent entry was a data transcription error because that is the control efficiency for water injection applied to oil-fired turbines.

Table 3-4. Summary of Cost Effectiveness and Supporting Data for DLN Combustion

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio
		Avg. ppmvd	tpy			
Small (4-23)	1999	152	<365	25	300	5.0
Large (170)	1999	210	>365	25	130	7.4

Based on regression of the data in both analyses, the best fit trend lines are represented by the following revised equations for both uncontrolled and RACT baseline scenarios:

Total capital investment (1999 dollars) = 2860.6 x (MMBtu/hr) + 25427 (R^2=1.0)

Total annual cost (1999 dollars) = 584.5 x (MMBtu/hr) ^ $^{0.96}$ (R^2=0.95)

3.3.4 SCR and Water Injection; Gas Turbines—Natural Gas (NSCRWGTNG)

Recommended updates to the costs for SCR combined with water injection are based on two sets of cost analyses. One set of costs is in 1999 dollars for three turbines ranging in size from 4.2 MW to 161 MW (OSEC, 1999). The second is in 2008 dollars for two larger turbines with design outputs of 50 MW and 180 MW (ECP, 2008). For SCR, the referenced analyses estimated direct installation costs and indirect costs based on scaling from the purchased equipment costs using standard factors as in the Control Cost Manual. Annual costs were estimated for the same cost elements that were used in the SCR analysis in the 1993 ACT. Water injection costs for the two smallest turbines in the 1999 analysis were estimated as described above for the water injection control option. Water injection costs for the large turbines were not estimated in the referenced analyses.

For the purposes of developing 1999 cost inputs for the CMDB, we made the following changes to the data and assumptions used in the OSEC analysis:

- Increased the engineering cost for SCR for the 161 MW turbine from $100,000 to $228,865. The revised value is equal to 10 percent of the purchased equipment cost, which is consistent with the approach used for the smaller turbines. The report did not explain why $100,000 was used instead of the factor.

- Estimated performance penalty costs and electricity costs for the blower and pumps in the ammonia injection system using operating hours of 8,000 hr/yr instead of 8,400 hr/yr.

- Calculated capital recovery for the SCR system using an interest rate of 7 percent instead of 10 percent.

- Calculated annual catalyst replacement and disposal costs using a future worth factor instead of a capital recovery factor.

- Estimated total capital investment and total annual costs for the 161 MW turbine using the regression equations for the water injection control option. (Maybe it would be better to drop the large model from this analysis and just present 1999 costs for small turbines and 2008 costs for large turbines.)

For the purposes of developing 2008 cost inputs for the CMDB, we started with the ECP analysis for SCR costs and then made the following changes to the data and assumptions:

- Calculated the performance penalty for SCR using an electricity cost of $0.06/kwh instead of $0.1/kwh and 8,000 hr/yr instead of 8,400 hr/yr. In addition, although it appears that the referenced analysis assumed a performance loss equal to 0.5 percent of the turbine's design output, the cited cost was significantly greater than it should be for that percentage loss, even if the cited electricity cost and operating hours were used in the calculation. We changed the cost to be consistent with the calculated amount.

- Calculated capital recovery for the SCR system using an interest rate of 7 percent instead of 10 percent.

- Estimated capital costs for water injection in 1999 dollars using the regression equation for the water injection control option, and then scaled the costs to 2008 dollars using the CEPCI.

- Estimated total annual costs for water injection following the same procedure described in Section 3.2.2 for the water injection portion of a combined water injection and EMx control measure. Thus, the total annual costs for water injection are the same in both control measures.

Table 3-5 summarizes the recommended new cost effectiveness and capital to annual cost ratios values for implementing SCR plus water injection on natural gas-fired combustion turbines. Table 3-5 also presents revised incremental costs of SCR relative to a RACT baseline of water injection for the different categories of turbines. Note that the SCR outlet NOx level was assumed to be 2.5 ppmvd in the ECP analysis, which results in an overall control efficiency of 98 percent versus the 94 percent for the OSEC and ACT analyses.

Table 3-5. Summary of Cost Effectiveness and Supporting Data for SCR Plus Water Injection

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		SCR Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of WI, $/ton NOx
		Avg. ppmvd	tpy				
Small (4.2)	1999	134	<365	9	2,790	3.0	5,840
Small (22.7)	1999	174	>365	9	1,370	2.9	3,130
Large (161)	1999	210	>365	9	1,070	1.5	1,690
Large (50-180)	2008	160[a]	>365	2.5	1,830	2.7	3,170

[a]Uncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

Based on regression of the data in both analyses, the revised best fit trend lines are represented by the following power equations for both uncontrolled scenarios (R^2=1 for the 2008 costs because the analysis was based on only two data points):

$$\text{Total capital investment (1999 dollars)} = 62962 \times (\text{MMBtu/hr})^{0.66} \quad (R^2=1.0)$$

$$\text{Total annual cost (1999 dollars)} = 8590 \times (\text{MMBtu/hr})^{0.87} \quad (R^2=0.99)$$

$$\text{Total capital investment (2008 dollars)} = 34533 \times (\text{MMBtu/hr})^{0.85} \quad (R^2=1.0)$$

$$\text{Total annual cost (2008 dollars)} = 6794 \times (\text{MMBtu/hr})^{0.94} \quad (R^2=1.0)$$

Revised best fit equations for incremental SCR costs relative to a RACT baseline of water injection are (R^2=1 for the 2008 costs because the analysis was based on only two data points):

$$\text{Total capital investment (1999 dollars)} = 37193 \times (\text{MMBtu/hr})^{0.63} \quad (R^2=1.0)$$

$$\text{Total annual cost (1999 dollars)} = 12065 \times (\text{MMBtu/hr})^{0.64} \quad (R^2=1.0)$$

$$\text{Total capital investment (2008 dollars)} = 10323 \times (\text{MMBtu/hr})^{0.96} \quad (R^2=1.0)$$

$$\text{Total annual cost (2008 dollars)} = 3106.1 \times (\text{MMBtu/hr})^{0.94} \quad (R^2=1.0)$$

3.3.5 SCR and Steam Injection; Gas Turbines—Natural Gas (NSCTSGTNG)

Combined costs for SCR and steam injection were not presented in any available references. Thus, costs for combined control systems were estimated in 1999 dollars for four model turbines ranging from 4 MW to 161 MW using the procedures described above for steam injection alone and for SCR as part of combined SCR and water injection control systems. Specifically, steam injection costs for each model turbine were assumed to be the same as in the 1993 ACT, consistent with the description above for steam injection control costs. Since OSEC did not estimate SCR costs for the specific turbines in this analysis, we estimated the SCR costs using the trendlines that we developed for incremental SCR costs relative to a RACT baseline of water injection. We then summed the separate SCR and steam injection costs to obtain the combined system costs.

We also estimated costs for a combined steam injection and SCR control measure in 2008 dollars. The SCR portion of the costs are the same as for SCR in the combined water injection plus SCR control measure, as described in Section 3.3.4. Total capital investment for the steam injection portion were estimated in 1999 dollars using the regression equation developed for steam injection alone, as described in Section 3.3.2. These costs were escalated to 2008 costs using the CEPCI. Total annual costs for steam injection were first estimated in 1999 dollars using the regression equation for the steam injection control option (see Section 3.3.2). On average, 40 percent of these costs were estimated to be for indirect costs that are factored from the system capital cost, and the remaining 60 percent is for direct annual costs and overhead. To estimate the total annual costs for steam injection in 2008, the indirect costs were scaled from the 1999 estimate using the CEPCI, and the direct annual costs and overhead were assumed to be the same as in 1999.

Table 3-6 summarizes the recommended new cost effectiveness and capital to annual cost ratios values for implementing SCR plus steam injection on natural gas-fired combustion turbines. Table 3-6 also presents revised incremental costs of SCR relative to a RACT baseline of steam injection for the different categories of turbines. Note that the incremental costs are slightly different from the costs in Table 3-5. The costs should be the same for a given turbine category. They differ because the two analyses examined a different number of turbines, and the sizes were not exactly the same. At a later date, the analysis could be improved by combining the SCR costs from both analyses and developing a single set of incremental SCR costs.

Table 3-6. Summary of Cost Effectiveness and Supporting Data for SCR Plus Steam Injection (SI)

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		SCR Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of SI, $/ton NOx
		Avg. ppmvd	tpy				
Small (4.2)	1999	155	<365	9	2,570	3.3	5,550
Small (26.8)	1999	142	>365	9	1,380	3.1	2,870
Large (83–161)	1999	300	>365	9	570	2.7	1,810
Large (50–180)	2008	160[a]	>365	2.5	1,420	3.9	3,170

[a] Uncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

Based on regression of the data in the analysis, the revised best fit trend lines are represented by the following power equations for the uncontrolled scenario (R^2=1 for the 2008 costs because the analysis was based on only two data points):

$$\text{Total capital investment (1999 dollars)} = 72169 \times (\text{MMBtu/hr})^{0.66} \quad (R^2=0.99)$$

$$\text{Total annual cost (1999 dollars)} = 17551 \times (\text{MMBtu/hr})^{0.72} \quad (R^2=0.98)$$

$$\text{Total capital investment (2008 dollars)} = 46492 \times (\text{MMBtu/hr})^{0.82} \quad (R^2=1.0)$$

$$\text{Total annual cost (2008 dollars)} = 8704 \times (\text{MMBtu/hr})^{0.86} \quad (R^2=1.0)$$

Revised best fit equations for incremental SCR costs relative to a RACT baseline of steam injection are assumed to be the same as noted above in the discussion of costs for SCR and water injection.

3.3.6 SCR and Dry Low NOx Combustion; Gas Turbines—Natural Gas (NSCRDGTNG)

Updated costs for combined SCR and DLN combustion control systems were estimated in 1999 dollars for all turbine sizes, 2007 dollars for small turbines, and 2008 dollars for large turbines. The 1999 costs were estimated by combining the separate costs for DLN combustion and SCR provided by Onsite Sycom Energy Systems (OSEC, 1999). The 2007 costs were estimated by combining SCR costs developed by Energy and Environmental Analysis in a report prepared for EPA with the OSEC costs for DLN combustion in 1999 dollars, escalated to 2007 dollars (EEA, 2008). Similarly, costs in 2008 dollars were estimated by combining SCR costs developed by EmeraChem Power in an analysis for the Bay Area Air Quality Management District with escalated DLN combustion costs (ECP, 2008). The EEA analysis provided only capital costs; therefore, we estimated annual costs using the same factors provided in ECP's analysis of costs in 2008 dollars. For both the 2007 and 2008 cost estimates, DLN capital costs and capital recovery were escalated from 1999 dollars using the CEPCI, and annual parts and repairs costs were assumed to be the same in all three years.

Table 3-7 summarizes the recommended new cost effectiveness and capital to annual cost ratios values for implementing SCR plus dry low NOx combustion on natural gas-fired combustion turbines. Table 3-7 also presents revised incremental costs of SCR relative to a RACT baseline of steam injection for the different categories of turbines. Note that the SCR outlet NOx level was assumed to be 2.5 ppmvd in the ECP analysis, which results in an overall control efficiency of 98 percent versus the 94 percent for the OSEC analyses. We also used an outlet concentration of 2.5 ppmvd to estimate emissions to use with EEA's 2007 costs. The ECP and EEA analyses did not specify inlet NOx emissions concentrations to the SCR; therefore, we assumed 25 ppmvd, as in other DLN analyses. We also assumed an average uncontrolled emissions level of 160 ppmvd for all models so that the overall control efficiency of the DLN combustion plus the SCR was 98 percent. Note that the incremental costs in 1999 dollars are significantly higher than those for SCR following water injection and steam injection; this is due to the inlet concentration being 25 ppmvd for this analysis and 42 ppmvd for water injection and steam injection.

Table 3-7. Summary of Cost Effectiveness and Supporting Data for SCR Plus DLN Combustion

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		SCR Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of DLN, $/ton NOx
		Avg. ppmvd	tpy				
Small (4.2)	1999	134	<365	9	1,800	2.9	11,900
Small (26.8)	1999	174	>365	9	990	3.6	6,320
Large (161)	1999	210	>365	9	390	4.2	3,340
Small (1–10.2)	2007	160[a]	<365	2.5	2,910	4.3	18,900
Small (25)	2007	160[a]	>365	2.5	1,460	3.8	7,510
Large (50–180)	2008	160[a]	>365	2.5	1,040	4.5	5,560

[a]Uncontrolled concentrations were not reported in the referenced analysis. Thus, the value used in this analysis is an assumed average that results in the estimated 84 percent reduction for DLN combustion, as described in Section 3.3.3 of this report.

Based on regression of the data in each analysis, the best fit trend lines are represented by the following power equations for uncontrolled scenarios (R^2=1 for the 2008 costs because the analysis was based on only two data points, and note that the R^2 for the 2007 equations is not meaningful because the DLN portion of the costs are based on a regression equation instead of independent, model-specific data):

$$\text{Total capital investment (1999 dollars)} = 24854 \times (\text{MMBtu/hr})^{0.79} \quad (R^2=1.0)$$

$$\text{Total annual cost (1999 dollars)} = 12725 \times (\text{MMBtu/hr})^{0.69} \quad (R^2=1.0)$$

$$\text{Total capital investment (2007 dollars)} = 187647 \times (\text{MMBtu/hr})^{0.54} \quad (R^2=1.0)$$

$$\text{Total annual cost (2007 dollars)} = 2782 \times (\text{MMBtu/hr}) + 167494 \quad (R^2=1.0)$$

$$\text{Total capital investment (2008 dollars)} = 14790 \times (\text{MMBtu/hr})^{0.97} \quad (R^2=1.0)$$

$$\text{Total annual cost (2008 dollars)} = 5263.5 \times (\text{MMBtu/hr})^{0.90} \quad (R^2=1.0)$$

The equations to estimate incremental costs for SCR relative to a RACT baseline of dry low NOx combustion in 1999 dollars and 2008 dollars are assumed to be the same as noted in Section 3.3.4 for incremental costs relative to a RACT baseline of water injection. Incremental costs for SCR relative to a RACT baseline of water injection in 2007 dollars are estimated using the following equations:

$$\text{Total capital investment (2007 dollars)} = 210883 \times (\text{MMBtu/hr})^{0.46} \quad (R^2=1.0)$$

$$\text{Total annual cost (2007 dollars)} = 1894 \times (\text{MMBtu/hr}) + 185570 \quad (R^2=0.99)$$

3.3.7 Water Injection; Gas Turbines—Oil (NWTINGTOL)

No new data are available on costs of water injection for oil-fired combustion turbines. However, because the water injection costs for natural gas-fired turbines were determined to be essentially the same in 1999 as in 1990, we assume the same would be true for water injection on oil-fired turbines; the costs for both types of turbines also were the same in the 1993 ACT analysis. Therefore, we recommend continuing to base costs on the results of the 1993 ACT analysis, but to update the cost year from 1990 to 1999. In addition, we changed the size of the large model in the ACT analysis from 83.3 MW to 84.7 MW because it appears the incorrect model was used in the ACT analysis. As for the natural gas-fired turbines, we also recommend splitting the single record for small sources into two records—one for source with uncontrolled NOx emissions <365 tpy, and the other for sources with uncontrolled NOx emissions >365 tpy. The resulting cost effectiveness values for the turbines with uncontrolled NOx emissions <365 tpy and >365 tpy are $1,630/ton of NOx and $960/ton of NOx, respectively. The capital to annual cost ratios also change slightly.

As for other control technologies, the constants in the equations to estimate total capital costs and total annual costs differ from those in the regression analyses performed in Excel. In this case, the differences are small, but we recommend revising the constants so that all equations are developed based on the same approach. The revised equations for both the uncontrolled and RACT baseline scenarios are:

$$\text{Total capital investment (1999 dollars)} = 43255 \times (\text{MMBtu/hr})^{\wedge\, 0.60}\ (R^2=1.0)$$

$$\text{Total annual cost (1999 dollars)} = 6796.8 \times (\text{MMBtu/hr})^{\wedge\, 0.80} (R^2=1.0)$$

3.3.8 SCR and Water Injection; Gas Turbines—Oil (NSCRWGTNG)

SCR costs were developed in a BACT analysis for a 48 MW oil-fired combustion turbine (FMPA, 2004). Because water injection costs in 2004 dollars are not available, we calculated costs in 1999 dollars as described above for the water injection option, and then estimated costs in 2004 dollars by scaling up the 1999 capital costs (and capital recovery) using the CEPCI; other annual operating and maintenance costs were assumed to be unchanged. We used the SCR capital cost as presented in the FMPA analysis, but we made several changes to the annual costs. Although the original values may have been appropriate for the specific application evaluated by FMPA, the following changes were made to be consistent with the calculations for other controls in this analysis:

- Estimated O&M costs assuming operation for 8,000 hr/yr instead of 4,422 hr/yr.
- Excluded cost for one week of lost power generation while catalyst is being replaced, assuming that catalyst replacement can be performed during scheduled annual downtime.
- Reduced sales tax and freight cost for catalyst from 12.25 percent of the purchased cost to 8 percent of the purchased cost.
- Deleted capital recovery cost for catalyst because the catalyst is replaced annually.

- The reported annual cost for ammonia was based on a stoichiometric ratio of 1.4 (possibly because they assumed a significant generation of NO2 relative to NO). They also applied a factor of 1.05, apparently to account for ammonia slip, as in the Control Cost Manual procedures for SCR on boilers. However, both factors should not be needed. For this analysis, we used just the 1.05 factor (also used the reported unit cost of $750/ton of ammonia, which may have been high for 2004).

- Reduced the property tax factor from 2.75 percent of the TCI to 1 percent of the TCI.

Table 3-8 summarizes the recommended cost effectiveness and capital to annual cost ratios values for implementing SCR plus water injection on oil-fired combustion turbines. Table 3-8 also presents incremental costs of SCR relative to a RACT baseline of water injection. The 1990 costs are essentially the same as the costs currently in the CMDB, except that we recommend splitting the one record for small sources into two records.

Table 3-8. Summary of Cost Effectiveness and Supporting Data for SCR Plus Water Injection (WI) for Oil-Fired Turbines

Turbine Output, MW	Cost Year	Uncontrolled NOx Emissions		SCR Outlet Concentration, ppmvd	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio	Incremental Cost Relative to RACT Baseline of WI, $/ton NOx
		Avg. ppmvd	tpy				
Small (3.3)	1990	179	<365	18	3,200	2.9	7,620
Small (26.3)	1990	211	>365	18	1,320	2.3	2,450
Large (84)	1990	228	>365	18	1,000	2.4	2,210
Large (48)	2004	200[a]	>365	5	1,560	2.3	4,790

aThe referenced analysis did not report an uncontrolled emissions level. The value used in this analysis is the average of the uncontrolled emissions concentrations for oil-fired model turbines in the 1993 ACT.

Based on regression of the data in the 1993 ACT, the best fit trend lines are represented by the following revised power equations for the uncontrolled scenario:

$$\text{Total capital investment (1990 dollars)} = 95837 \times (\text{MMBtu/hr})^{0.62} \quad (R^2=0.99)$$

$$\text{Total annual cost (1990 dollars)} = 25990 \times (\text{MMBtu/hr})^{0.70} \quad (R^2=1.0)$$

Revised best fit equations for incremental SCR costs relative to a RACT baseline of water injection are:

$$\text{Total capital investment (1990 dollars)} = 4744 \times (\text{MMBtu/hr}) + 368162 \quad (R^2=1.0)$$

$$\text{Total annual cost (1990 dollars)} = 1522.5 \times (\text{MMBtu/hr}) + 142643 \quad (R^2=1.0)$$

We could not develop equations for this control system in 2004 dollars because 2004 data are available for only one turbine, and thus are insufficient for this purpose.

3.3.9 Water Injection; Gas Turbines—Jet Fuel (NWTINGTJF)

The current CMDB assumes costs for jet fuel-fired turbines are the same as for oil-fired turbines. Thus, we recommend the same changes for jet fuel fired turbines as noted above for oil-fired turbines.

3.3.10 SCR and Water Injection; Gas Turbines—Jet Fuel (NSCTWGTJF)

The current CMDB assumes costs for jet fuel-fired turbines are the same as for oil-fired turbines. Thus, we recommend the same changes for jet fuel fired turbines as noted above for oil-fired turbines.

3.3.11 Applicable Control Measures for Gas Turbine SCCs

The first column in Table 3-9 lists all of the gas turbine SCCs that are associated with one or more gas turbine control measures in the CMDB table called “Table 03_SCCs.” In addition, the last seven SCCs in Table 3-9 are additional gas turbine SCCs that are not currently assigned any NOx control measures in the CMDB. These seven SCCs, as well as many of the others at the top of Table 3-9, were identified with NOx emissions in an EPA query of the NEI for facilities in the Ozone Transport Group Assessment Region (i.e., 37 states that are partially or completely to the east of 100°W longitude). The first 11 control measures in column headings in Table 3-9 are the gas turbine control measures that are currently in the CMDB; the last three column headings are the new control measures identified in this review and described in Section 3.2 of this report.

Each control measure that was determined to be applicable for a specific SCC is identified by either an “E” or an “N” in the cell at the intersection of the applicable SCC row and the control measure column. An “E” means the control measure is already listed in the CMDB for the particular SCC, and we concur with that designation. An “N” means the control measure is not currently linked to a particular SCC, but we recommend adding this link in the database. In some cases, we recommend applying new links between existing control measures and existing SCCs. For example, some of the SCCs are for turbines that are fired with relatively uncommon fuels such as landfill gas or gasoline. We have not located any analyses that determined the applicable controls and related costs for gas turbines fired with such fuels. In order to conduct CoST modeling analyses for these turbines, the most representative available control measures

Table 3-9. Recommended Control Measures for Gas Turbine SCCs

SCC[a]	SCC Level 1[b]	SCC Level 2[c]	SCC Level 3	SCC Level 4	Applicable Gas Turbine Control Measures for the SCC[d]													
					NWTINGTOL	NSCRWGTOL	NWTINGTJF	NSCRWGTJF	NWTINGTNG	NSTINGTNG	NDLNCGTNG	NSCRWGTNG	NSCRSGTNG	NSCRDGTNG	NWIGTAGT	NCATCGTNG	NEMXWGTNG	NEMXDGTNG
20200101	ICE	Ind	Distillate Oil (Diesel)	Turbine	E	E												
20200103	ICE	Ind	Distillate Oil (Diesel)	Turbine: Cogeneration	E	E												
20200108	ICE	Ind	Distillate Oil (Diesel)	Turbine: Evap Losses	D	D												
20200109	ICE	Ind	Distillate Oil (Diesel)	Turbine: Exhaust	E	E												
20200201	ICE	Ind	Natural Gas	Turbine					E	E	E	E	E	E	D	N	N	N
20200203	ICE	Ind	Natural Gas	Turbine: Cogeneration					E	E	E	E	E	E	D	N	N	N
20200208	ICE	Ind	Natural Gas	Turbine: Evap Losses					D	D	D	D	D	D	D			
20200209	ICE	Ind	Natural Gas	Turbine: Exhaust					E	E	E	E	E	E	D	N	N	N
20200701	ICE	Ind	Process Gas	Turbine					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20200705	ICE	Ind	Process Gas	Refinery Gas: Turbine					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20200713	ICE	Ind	Process Gas	Turbine: Evap Losses											D			
20200714	ICE	Ind	Process Gas	Turbine: Exhaust					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20200901	ICE	Ind	Kerosene/Naphtha (Jet Fuel)	Turbine			E	E										
20200908	ICE	Ind	Kerosene/Naphtha (Jet Fuel)	Turbine: Evap Losses			D	D										
20200909	ICE	Ind	Kerosene/Naphtha (Jet Fuel)	Turbine: Exhaust			E	E										
20201008	ICE	Ind	Liquified Petroleum Gas (LPG)	Turbine: Evap Losses											D			

(continued)

Table 3-9. Recommended Control Measures for Gas Turbine SCCs (continued)

					Applicable Gas Turbine Control Measures for the SCC[d]													
SCC[a]	SCC Level 1[b]	SCC Level 2[c]	SCC Level 3	SCC Level 4	NWTINGTOL	NSCRWGTOL	NWTINGTJF	NSCRWGTJF	NWTINGTNG	NSTINGTNG	NDLNCGTNG	NSCRWGTNG	NSCRSGTNG	NSCRDGTNG	NWIGTAGT	NCATCGTNG	NEMXWGTNG	NEMXDGTNG
20201009	ICE	Ind	Liquified Petroleum Gas (LPG)	Turbine: Exhaust	N[e]	N[e]									D			
20201011	ICE	Ind	Liquified Petroleum Gas (LPG)	Turbine	N[e]	N[e]									D			
20201013	ICE	Ind	Liquified Petroleum Gas (LPG)	Turbine: Cogeneration	N[e]	N[e]									D			
20300102	ICE	C/I	Distillate Oil (Diesel)	Turbine	E	E												
20300108	ICE	C/I	Distillate Oil (Diesel)	Turbine: Evap Losses	D	D												
20300109	ICE	C/I	Distillate Oil (Diesel)	Turbine: Exhaust	E	E												
20300202	ICE	C/I	Natural Gas	Turbine					E	E	E	E	E	E	D	N	N	N
20300203	ICE	C/I	Natural Gas	Turbine: Cogeneration					E	E	E	E	E	E	D	N	N	N
20300208	ICE	C/I	Natural Gas	Turbine: Evap Losses					D	D	D	D	D	D	D			
20300209	ICE	C/I	Natural Gas	Turbine: Exhaust					E	E	E	E	E	E	D	N	N	N
20300701	ICE	C/I	Digester Gas	Turbine					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20300708	ICE	C/I	Digester Gas	Turbine: Evap Losses											D			
20300709	ICE	C/I	Digester Gas	Turbine: Exhaust					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20300801	ICE	C/I	Landfill Gas	Turbine					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20300808	ICE	C/I	Landfill Gas	Turbine: Evap Losses											D			
20300809	ICE	C/I	Landfill Gas	Turbine: Exhaust					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20400301	ICE	ET	Turbine	Natural Gas					N	N	N	N	N	N	D	N	N	N
20400304	ICE	ET	Turbine	Landfill Gas					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]

(continued)

Table 3-9. Recommended Control Measures for Gas Turbine SCCs (continued)

SCC[a]	SCC Level 1[b]	SCC Level 2[c]	SCC Level 3	SCC Level 4	Applicable Gas Turbine Control Measures for the SCC[d]													
					NWTINGTOL	NSCRWGTOL	NWTINGTJF	NSCRWGTJF	NWTINGTNG	NSTINGTNG	NDLNCGTNG	NSCRWGTNG	NSCRSGTNG	NSCRDGTNG	NWIGTAGT	NCATCGTNG	NEMXWGTNG	NEMXDGTNG
50100420	WD	SWD-G	Landfill Dump	Waste Gas Recovery: GT					N[e]	N[e]	N[e]	N[e]	N[e]	N[e]	D	N[e]	N[e]	N[e]
20201609	ICE	Ind	Methanol	Turbine: Exhaust	N[e]	N[e]												
20201701	ICE	Ind	Gasoline	Turbine	N[e]	N[e]												
20300901	ICE	C/I	Kerosene/Naphtha (Jet Fuel)	Turbine: JP-4			N	N										
20400302	ICE	ET	Turbine	Diesel/Kerosene	N	N												
20400303	ICE	ET	Turbine	Distillate Oil	N	N												
20400305	ICE	ET	Turbine	Kerosene/Naphtha			N	N										
20400399	ICE	ET	Turbine	Other Not Classified[f]	N[e]	N[e]												

[a]SCCs in regular font are associated with one or more gas turbine control measures in the current CMDB. The SCCs in bold font represent gas turbine activities that were identified with NOx emissions in the Ozone Transport Assessment Group Region analysis but are not associated with gas turbine control measures in the current CMDB.

[b]ICE means "Internal Combustion Engines" and WD means "Waste Disposal."

[c]Ind means "Industrial," C/I means "Commercial/Institutional," ET means "Engine Testing," and SWD-G means "Solid Waste Disposal-Government."

[d]An "E" means the control measure is currently associated with the SCC in the CMDB, and no changes are recommended. A "D" means the control measure is currently associated with the SCC, but this control measure should be deleted because it is not appropriate for the SCC. An "N" means the control measure is not currently associated with the SCC in the CMDB, but adding it is recommended.

[e]The control measure is assumed to be representative for the SCC; control cost data are unavailable for the specific fuel type for the SCC.

[f]The fuel type is unknown. For the purposes of this analysis it is assumed to be a liquid because most of the emissions identified for the engine testing SCCs in the analysis done in the Ozone Transport Assessment Group Region were from liquid fuel-fired turbines.

should be assigned. For turbines that burn miscellaneous gaseous fuels, the most representative control measures are those for natural gas-fired turbines. Similarly, for turbines that burn miscellaneous liquid fuels, the most representative available control measures are those for oil-fired turbines. The description field in the CMDB table called "Table 02_Efficiencies" could be revised to indicate that the control measures for natural gas units are assumed to be applicable for all gaseous fuel fired units, and the control measures for oil-fired units are assumed to be applicable for all liquid fuel-fired units (note that the separate control measures already in the CMDB for jet fuel-fired turbines are also based on the data for oil-fired units).

Finally, gas turbine SCCs for evaporative losses from turbine fuel storage and delivery systems are associated with NOx control measures in the current CMDB. We recommend deleting these NOx control measure/SCC records from the CMDB table called "Table 03_SCCs" because there should be no NOx emissions from the sources represented by these SCCs. These control measure/SCC combinations are identified with a "D" in the applicable cells in Table 3-9.

3.4 Example Emission Limits for NonEGU Combustion Turbines

NonEGU combustion turbines are subject to several emission regulations, including NSPS in 40 CFR part 60 and various state regulations. Example emission limits in state regulations are presented in Table 3-10.

Table 3-10. NOx Emissions Limits for NonEGU Combustion Turbines in New York

State	Type of Service	Type of Combustion Turbine Operating Cycle	Emission Limit	Effective Date
New York[a]	Any—gaseous fuel	Combined cycle	42 ppmdv (at 15% O2)	Current
		Simple cycle or regenerative cycle	50 ppmdv (at 15% O2)	Current
	Any—oil-fired	Combined cycle	65 ppmdv (at 15% O2)	Current
		Simple cycle or regenerative cycle	100 ppmdv (at 15% O2)	Current

[a]The requirements apply to combustion turbines with a maximum heat input rate greater than or equal to 10 million Btu per hour at major sources of NOx emissions. The specified limits apply until July 1, 2014; beginning on July 1, 2014, owners/operators must submit a proposal for RACT (NYCRR, 2014).

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SECTION 4
GLASS MANUFACTURING SECTOR

4.1 Introduction

The control cost database separates the glass manufacturing sector into four different types; flat glass, container glass, pressed glass, and general glass manufacturing. The CMDB listed six different control technologies for NOx emissions which were all reviewed in 2006 and included cullet preheat, oxy-firing, electric boost, low NOx burners, selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). A literature and internet search was conducted to find any new control technologies for NOx or any updates to existing controls regarding cost and efficiencies. Operating permits for some glass manufacturing plants were reviewed and control system vendors were also contacted for information. A brief summary of data from each reference reviewed in included in the spreadsheet "CoST_Glass Mfg.xlsx."

4.2 Example NOx Regulatory Limits

4.2.1 Wisconsin

Glass manufacturing furnace with a maximum heat input capacity equal to or greater than 50 mmBtu per hour, 2.0 pounds per ton of produced glass.[1]

4.2.2 New Jersey

Commercial container glass, specialty container glass, borosilicate recipe glass, pressed glass, blown glass, and fiberglass manufacturing furnaces: 4.0 lbs/ton glass removed. Flat glass manufacturing furnaces: 9.2 lbs/ton glass removed.

4.2.3 New York

NOx emissions are covered under NY's case-by case RACT regulations.

4.3 Recommended Additions

The following NOx controls are recommended additions for the glass manufacturing industry that are not currently in the control cost database, and a tabular summary of the costs is presented in Table 4-1.

- Electric Boost—Three entries for electric boost controls were in the CMDB for container, flat, and pressed glass manufacturing. A cost estimate for electric boost was found for "general" glass manufacturing (DOE, 2002), since the CMDB did not have a "general" entry for electric boost controls, an entry for "Electric Boost; Glass Manufacturing—General" was added with a new abbreviation of NELBOGMGN. The

[1] http://dnr.wi.gov/About/NRB/2007/January/01-07-3A4.pdf

reference provided an annualized cost of $7,100 per ton of NOx removed based on a 250 ton of glass per day glass melting furnace operating with an emission rate of 8-lb NOx per ton glass produced and a NOx removal efficiency of 30 percent. Since the reference did not provide capital costs, the capital to annual cost ratio could not be determined, and the capital recovery factor was assumed to be the same as the electric boost entries for container, flat, and pressed glass (i.e., 0.1424, assuming equipment life of 10 years).

- Oxy-firing—Three entries for oxy-firing were in the CMDB for container, flat, and pressed glass manufacturing. Similar to electric boost controls, an updated cost estimate for oxy-firing was found for "general" glass manufacturing (DOE, 2002); since the CMDB did not have a "general" entry for oxy-firing, an entry for "OXY-Firing; Glass Manufacturing—General" was added to the CMDB with a new abbreviation of NOXYFGMGN. The reference provided an annualized cost of $2,352 per ton of NOx removed based on a 250 ton of glass per day glass melting furnace emitting 8-lb NOx per ton glass produced and a NOx removal efficiency of 85 percent.[1] Since the capital costs were not provided the capital to annual cost ratio and the capital recovery factor were assumed to be the same as the oxy-firing entries for container, flat, and pressed glass, which all had the same values.

- Catalytic Ceramic Filter—This new control technology for NOx reduction was not previously in the database and was added for flat glass manufacturing with a new abbreviation of CATCFGMFT. A vendor was contacted for information (2013 Vendor Quote). The minimum and maximum cost per ton estimates were based on regenerative gas-fired furnace with pull rates of 600 tons per day and 490 tons per day, respectively. The estimate provided by the vendor included capital cost, annualized capital costs, and annual operational cost in 2013 dollars; it also included NOx reductions based on a 95 percent NOx efficiency.

Table 4-1. Summary of Cost Effectiveness and Supporting Data for Recommended Additions

Technology	Furnace Production Rate (ton/day)	Cost Year	NOx Removal Efficiency (%)	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio
Electric Boost (general)	250	2002	30	7,100	N/A[a]
Oxy-firing General	250	2002	85	2,352	2.7
Catalytic Ceramic Filter	490	2013	95	1,045	4.6
	600	2013	95	997	4.6

[a]The ratio cannot be calculated because capital costs are not available.

4.4 Recommended Changes

Changes to the CMDB are recommended for the following three types of control measures, which are also summarized in Table 4-2.

- Low NOx Burner General—Three entries for Low NOX burners were in the cost database for container, flat, and pressed glass manufacturing. An updated cost estimate for low NOx burners for flat glass and container glass manufacturing (EC, 2013) was found and entries NLNBUGMCN and NLNBUGMFT were updated. The reference provided capital costs and an annualized cost in euros per kilogram of NOx removed which was converted to dollars per ton of NOx. For flat glass the minimum cost per ton estimate was based on a 900 ton per day gas fired furnace, and the maximum cost per ton estimate was based on a 500 ton per day gas fired furnace. For container glass the minimum cost per ton estimate was based on 450 ton per day gas fired furnace, and the maximum cost per ton estimate was based on a 200 ton per day gas fired furnace. The capital recovery factor and the capital to annual cost ratio were also updated. We also recommend changing the equipment life for low NOx burners on flat glass furnaces from 3 years to 10 years (EC, 2013).

  Additionally, equations for low NOx burners were added for entries NLNBUGMCN and NLNBUGMFT to "Table 04_Equations" of the CMDB based on the best fit trend lines of the total capital investment and total annual cost for the facilities with the production levels described above, the best fit trend line results were as follows:

  NLNBUGMCN (The correlation coefficients are high because the data are from a single source, and they may reflect data points from a correlation performed by that source)

  Total capital investment (2007 dollars) = 30,930 x $(\text{tons/day})^{0.45}$ ($R^2 = 0.99$)

  Total annual cost (2007 dollars) = 9,377 x $(\text{tons/day})^{0.40}$ ($R^2 = 0.99$)

  NLNBUGMFT (The correlation coefficients are a perfect 1.0 because only two data points are available)

  Total capital investment (2007 dollars) = 527 x (tons/day) + 664,557 ($R^2 = 1.0$)

  Total annual cost (2007 dollars) = 132x (tons/day) + 150,105 ($R^2 = 1.0$)

- Cullet Preheating—Two entries for cullet preheating controls were in the cost database for container and pressed glass manufacturing. An updated annualized cost per ton value and NOx efficiency for pressed and container glass entries (IT, 2002) were found and updated for entries NCLPTGMCN and NCUPHGMPD. The reference provided an annualized cost of $5,000 per ton of NOx removed based on a 250 ton of glass per day glass melting furnace emitting 8-lb NOx per ton glass produced and a NOx removal efficiency of 5 percent.[1] Since the reference did not

[1] Annualized cost includes capital and O&M costs and is based on 2002 dollars.

provide capital costs separately, the capital to annual cost ratio and the capital recovery factor were not updated. Additionally, based on information from EPA's OECA staff, class entries for cullet preheating should be changed from "known" to "emerging" in Table 01_Summary of the CMDB because this control measure is technically feasible but has rarely been implemented.[1]

- Selective Catalytic Reduction—Three entries for selective catalytic reduction were in the CMDB for container, flat, and pressed glass manufacturing. An updated cost estimate for SCR for flat glass and container glass manufacturing (EC, 2013) was found, and entries NSCRGMCN and NSCRGMFT were updated. The reference provided capital costs and an annualized cost in euros per kilogram of NOx removed which was converted to dollars per ton of NOx.[2] For flat glass the minimum and maximum cost per ton estimates were based on a 900 and 500 ton per day gas fired furnace, respectively. For container glass the minimum and maximum estimates were based on a 450 and 200 ton per day gas fired furnaces, respectively. The capital to annual cost ratio were also updated.

  Equations for SCR were added for entries NSCRGMCN and NSCRGMFT to Table 4 of the CMDB based on the best fit trend lines of the total capital investment and total annual cost for the facilities with the production levels described above, the best fit trend line results were as follows:

  NSCRGMCN (The correlation coefficients are high because the data are from a single source, and they may reflect data points from a correlation performed by that source)

  Total capital investment (2007 dollars) = 79,415 x (tons/day) $^{0.51}$ ($R^2 = 0.99$)

  Total annual cost (2007 dollars) = 643 x (tons/day) + 135,302 ($R^2 = 1.0$)

  NSCRGMFT (The correlation coefficients are a perfect 1.0 because only two data points are available)

  Total capital investment (2007 dollars) = 3681 x (tons/day) + 1.0E+06 ($R^2 = 1.0$)

  Total annual cost (2007 dollars) = 842 x (tons/day) + 424,930 ($R^2 = 1.0$)

1 Personal communication. Katie McClintock, US EPA/OCEA, with Larry Sorrels, US EPA/OAR/OAQPS, Feb. 13, 2014.

2 Conversion based on 2008 average exchange rate of 0.711. Source: http://www.irs.gov/Individuals/International-Taxpayers/Yearly-Average-Currency-Exchange-Rates

Table 4-2. Summary of Cost Effectiveness and Supporting Data for Recommended Additions

Technology	Furnace Production Rate (ton/day)	Cost Year	NOx Removed (tons/year)	Cost Effectiveness, $/ton NOx	Capital to Annual Cost Ratio
NLNBUGMCN	200	2007	66	1,365	4.2
	450	2007	100	1,072	4.3
NLNBUGMFT	500	2007	371	574	4.2
	900	2007	611	447	4.3
NCLPTGMCN	250	2002	5%	5,000	4.5
NCUPHGMPD	250	2002	5%	5,000	4.5
NSCRGMCN	200	2007	121	2,169	4.5
	450	2007	251	1,684	4.2
NSCRGMFT	500	2007	886	957	3.4
	900	2007	1,383	855	3.7

4.5 Recommended Deletions

- Selective Non-Catalytic Reduction—Three entries for selective non-catalytic reduction were in the cost database for container, flat, and pressed glass manufacturing. Based on conversations between EPA and OECA staff, SNCR entries for glass manufacturing should be removed based on recent NSR settlements that indicate SNCR is not a technically feasible control technology for the removal of NOx.[1]

4.6 Updates to Source Classification Codes

- There are twenty applicable SCCs for glass manufacturing as shown in Table 4-3.
- In an analysis of NO_X emissions for the Ozone Transport Assessment Group Region in 2011, fourteen of the SCCs in Table 4-3 were identified. The six SCCs not included in the Ozone Transport Region are shown at the bottom of Table 4-3. Four of the SCCs, 30501401, 30501402, 30501403, and 30501404 are associated with glass manufacturing NO_X controls in the current CMDB.
- Furnaces are the primary source of NOx emissions in the glass manufacturing industry, therefore NOx emission control techniques are typically for point emission sources associated with furnace emissions. The four SCCs identified in the CMDB pertain to four types of melting furnaces; general, flat, container, and pressed. The

[1] Personal communication. Katie McClintock, US EPA/OCEA, with Larry Sorrels, US EPA/OAR/OAQPS, Feb. 13, 2014.

remaining sixteen SCCs in Table 4-3 are not associated with furnaces. Therefore, no changes related to SCCs are recommended for the CMDB.

- For new control techniques added to the CMDB for glass manufacturing, the applicable SCC from Table 4-3 was added to the Description field for each control technique in Table 01_Summary in the CMDB (Table C-1of Appendix C of this report). These related control measures and SCCs should also be added to "Table 03_SCCs" in the CMDB.

Table 4-3. Applicable SCCs for the Glass Manufacturing Industry

SCC Code	SCC Level One	SCC Level Two	SCC Level Three	SCC Level Four
30501401[a]	Industrial Processes	Mineral Products	Glass Manufacture	Furnace/General**
30501402[a]	Industrial Processes	Mineral Products	Glass Manufacture	Container Glass: Melting Furnace
30501403[a]	Industrial Processes	Mineral Products	Glass Manufacture	Flat Glass: Melting Furnace
30501404[a]	Industrial Processes	Mineral Products	Glass Manufacture	Pressed and Blown Glass: Melting Furnace
30501406	Industrial Processes	Mineral Products	Glass Manufacture	Container Glass: Forming/Finishing
30501407	Industrial Processes	Mineral Products	Glass Manufacture	Flat Glass: Forming/Finishing
30501408	Industrial Processes	Mineral Products	Glass Manufacture	Pressed and Blown Glass: Forming/Finishing
30501410	Industrial Processes	Mineral Products	Glass Manufacture	Raw Material Handling (All Types of Glass)
30501411	Industrial Processes	Mineral Products	Glass Manufacture	General **
30501413	Industrial Processes	Mineral Products	Glass Manufacture	Cullet: Crushing/Grinding
30501414	Industrial Processes	Mineral Products	Glass Manufacture	Ground Cullet Beading Furnace
30501416	Industrial Processes	Mineral Products	Glass Manufacture	Glass Manufacturing
30501420	Industrial Processes	Mineral Products	Glass Manufacture	Mirror Plating: General
30501499	Industrial Processes	Mineral Products	Glass Manufacture	See Comment **
SCCs Not Included in the Ozone Transport Assessment Group Region:				
30501405	Industrial Processes	Mineral Products	Glass Manufacture	Presintering
30501412	Industrial Processes	Mineral Products	Glass Manufacture	Hold Tanks **
30501415	Industrial Processes	Mineral Products	Glass Manufacture	Glass Etching with Hydrofluoric Acid Solution
30501417	Industrial Processes	Mineral Products	Glass Manufacture	Briquetting
30501418	Industrial Processes	Mineral Products	Glass Manufacture	Pelletizing
30501421	Industrial Processes	Mineral Products	Glass Manufacture	Demineralizer: General

[a]Denotes SCCs included in the CMDB.

4.7 References

DOE, 2002. Oxygen Enriched Air Staging a Cost-effective Method For Reducing NOx Emissions. U.S. Department of Energy. Office of Industrial Technologies. April 2002. http://www1.eere.energy.gov/manufacturing/resources/glass/pdfs/airstaging.pdf

EC, 2013. Best Available Techniques (BAT) Reference Document for the Manufacture of Glass. European Commission 2013. http://eippcb.jrc.ec.europa.eu/reference/BREF/GLS_Adopted_03_2012.pdf

Vendor Quote 2013 – Confidential Business Information

SECTION 5
LEAN BURN ENGINES

The CMDB includes the following NO_X emissions control measures for Lean Burn Engines:

- Air to fuel ratio (AFR) (achieves 20 percent reduction)
- Air to fuel ratio (AFR) and Ignition retard (IR) (achieves 30 percent reduction)
- Ignition retard (IR) (achieves 20 percent reduction)
- Low emission combustion (achieves 87 percent reduction)
- Low emissions combustion, low speed (achieves 87 percent reduction)
- Low emissions combustion, medium speed (achieves 87 percent reduction)
- Nonselective catalytic reduction (NSCR) (achieves 90 percent reduction)
- Selective catalytic reduction (SCR) (achieves 90 percent reduction)
- Selective noncatalytic reduction (SNCR) (achieves 90 percent reduction)

Based on the literature review and the new cost data identified for Lean Burn control technologies, several changes to the CMDB are recommended. No changes to existing records in CMDB are recommended. The following sections outline the additions and other comments recommended for the CMDB in relation to NO_X emissions from Lean Burn Engines.

5.1 Literature Search

In order to update the existing control measures database, a literature search was conducted for articles and papers published since 2008 (to include 2008 through August 2013) using the following terms:

- engine
- lean burn
- cost
- NOx or “nitrogen oxides”
- scr or “selective catalytic reduction”
- turbocharge

- air/fuel ratio
- layered combustion
- high energy ignition
- high pressure fuel injection
- “low emission control” or LEC
- electronic engine control
- combustion modification
- timing
- exhaust gas recirculation
- lean NOx catalyst
- lean NOx trap
- control efficiency
- emission reduction

The literature search identified a total of 19 references, and the abstracts for these references were reviewed. Three references of potential interest were identified and two of these were obtained for review in the lean burn engine control device study.

5.2 Document Review

A brief summary of data from each reference reviewed in included in the spreadsheet “CoST_leanburn.xlsx,” in worksheet “Overall Sum—New Ref Review.” The information and data available from each reference is provided in table format, along with indication of whether the data were used or not.

There are 6 control technique additions to be added to the CMDB from 5 references.

The recommended additions include:

- Low Emission Combustion, LEC (for natural gas engines);
- Layered Combustion, LC (for 2 stroke natural gas engines);
- Layered Combustion, LC (for 2 stroke Large Bore natural gas engines);

- Air to Fuel Ratio Controller, AFRC;
- Selective Catalytic Reduction, SCR (for 4 stroke natural gas engines); and
- SCR (for diesel engines).

Recent cost data for these control techniques were available from reports dated 2001 through 2012.

The references for the added control techniques are included on the "**Table 06 References**" worksheet and are as follows:

OTC 2012. Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final. October 17, 2012.

SJVAPCD 2003. RULE 4702—Internal Combustion Engines—Phase 2. Appendix B, Cost Effectiveness Analysis for Rule 4702 (Internal Combustion Engines—Phase 2). San Joaquin Valley Air Pollution Control District. July 17, 2003. www.arb.ca.gov/pm/pmmeasures/ceffect/rules/sjvapcd_4702.pdf

CARB 2001. Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines. California Environmental Protection Agency, Air Resources Board, Stationary Source Division, Emissions Assessment Branch, Process Evaluation Section. November 2001.

EPA 2010. Alternative Control Techniques Document: Stationary Diesel Engines. March 5, 2010.

PA DEP 2013. Technical Support Document General Permit GP-5. Pennsylvania Department of Environmental Protection, Bureau of Air Quality. January 31, 2013.

5.3 Low Emission Combustion (LEC) (NLECICENG)

The costs and cost effectiveness for applying LEC to natural gas Lean Burn engines are obtained from the document *Appendix B, Cost Effectiveness Analysis for Rule 4702 (Internal Combustion Engines—Phase 2)* (SJVAPCD 2003). Information was provided on Capital costs, Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-1 for LEC along with changes in assumptions for the current analysis.

LEC are described as retrofit kits that allow engines to operate on extremely lean fuel mixtures to minimize NOx emissions. The LEC retrofit may include: (1) redesign of cylinder head and pistons to improve mixing (on smaller engines), (2) Precombustion chamber (on larger engines), lower cost, simple versions, (3) Turbocharger, (4) High energy ignition system,

Table 5-1. LEC for Natural Gas Lean Burn Engines

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: 80%	None.
Capital costs: provided for multiple models	None.
Annual Costs	
Equipment life: 10 yr	None.
Interest rate: 10%	Interest rate: 7%
Operating hours: 2000 hr/yr	None.
Emission rate, uncontrolled: 740 ppmv	Emission rate, uncontrolled: Assumed mid to upper end hp rating for each model.
Emission rate, controlled: 80% reduction	None.
Annualized equipment cost: provided for multiple model sizes	CRF: 0.1424
Annual O&M cost: assumed $0.	None.

(5) Aftercooler, and (6) Air to fuel ratio controller. (A discussion of individual technologies is provided in Appendix B of the original reference, pp. B-1 to B-28). No detail was provided on the exact combination of combustion modifications included in the example cost analysis; some references indicate that LEC on larger engines often includes a PCC (p.B-10) (CARB 2001). LEC are known or demonstrated control techniques for lean burn engines. An 80 percent NOx emission reduction can be achieved by LEC with little or no fuel penalty (in fact, LEC technologies are expected to decrease fuel consumption because they result in leaner burning engine, though the costs do not account for fuel consumption decrease). The original reference assumed an 80 percent reduction in the cost example.

Capital and annual costs were provided for multiple size ranges of engines. The capital costs ranged from $14,000 to $256,000. Costs for the 1000 to 3000 hp model were given as $40,000 to $256,000, and a mid-range cost of $148,000 was assumed in the current analysis. The total annual costs ranged from $2,000 to $21,000 (these costs are very similar to the costs calculated in the original reference analysis). The original reference assumed there are no annual operation and maintenance costs incurred from the combustion modification technologies, and the only annual cost provided is for annualized capital costs. No emission reductions are provided in the document (however the final cost effectiveness values are provided and the reduction assumed in the original analysis can be back-calculated). In the current analysis, a hp rating based on the middle or upper end of each size range was assumed for estimating the uncontrolled NOx emissions. An estimate of emissions was made in the current analysis. Uncontrolled NOx emissions were estimated based on an uncontrolled NOx concentration of 740 ppmv (this equates to approximately 9 g/bhp-hr), the operating hours were provided as 2000 hr/yr in the original reference, and controlled emissions were estimated based on 80 percent reduction as stated in the reference. Uncontrolled NOx emissions ranged from 1.1 to 34 tpy for the models, and the NOx reductions ranged from 0.90 to 27 tpy for the models.

The current analysis shows a cost effectiveness of $2,200/ton of NOx reduction to $780/ton for 2000 hr/yr operation, and the average cost effectiveness across all the models is $1,000/ton of NOx reduction.

The cost year is not provided in the reference; assumed the cost year is the date of the cited reference, 2001$.

Based on the cost calculations for engines of varying hp, the following equations were developed for the capital cost and annual costs for LEC on natural gas Lean Burn engines:

$$\text{Capital cost} = 16019\ e^{0.0016 \times (hp)}$$

$$\text{Annual cost} = 2280.8\ e^{0.0016 \times (hp)}$$

The R^2 value for these equations is 0.96. These equations should be included in the CoST database file under a new equation type.

See the cost calculations in worksheet “LEC (CARB)-2001” of the Excel file.

5.4 Layered Combustion (LC), 2 Stroke (NLCICE2SNG)

The costs and cost effectiveness for applying LC to natural gas Lean Burn engines (2 stroke) are obtained from the document *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions* (OTC 2012). Information was provided on Capital costs; assumptions were made to determine Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-2 for LC for 2 stroke engines, along with changes in assumptions for the current analysis.

LC consists of multiple combustion modification technologies. The combustion modifications included in this example are related to (1) Air supply; (2) Fuel supply, (3) Ignition, (4) Electronic controls, and (5) Engine monitoring (a discussion of individual technologies is provided on pp. 17 to 19 for 2 stroke Lean Burn engines). No significant detail was provided on which specific combustion modification technologies were applied. In the example study, 3 of the most representative manufacturer and models of 2 stroke Lean Burn engines used for integral compressors were selected for evaluation; these 3 engines were Cooper GMVH-10 2250 hp,

Table 5-2. LC for Natural Gas Lean Burn Engines, 2-stroke

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: Not provided.	Control efficiency: derived value is 97% (this is high)
Capital costs: based on cited ERLE 2009 project (First unit upgrade costs)	Capital costs: used average based on the provided range for each make/model engine.
Annual Costs	
Equipment life: Not provided.	Equipment life: 10 yr
Interest rate: Not provided.	Interest rate: 7%
Operating hours: Not provided.	Operating hours: 2000 hr/yr
Emission rate, uncontrolled: Not provided	Emission rate, uncontrolled: 16.8 g/bhp-hr
Emission rate, controlled: 0.5 g/bhp-hr	None.
Annualized equipment cost: Not provided.	CRF: 0.1424
Annual O&M cost: Not provided.	Annual O&M cost: $0.

Clark TLA-6 2000 hp, and Cooper GMW-10 2500 hp (cited ERLE 2009 report "ERLE Cost Study of the Retrofit Legacy Pipeline Engines to Satisfy 0.5 g/bhp-hr NOx"). LC are known or demonstrated control techniques for lean burn, 2 stroke engines. A NOx emissions rate of 0.5 g/bhp-hr was achieved. The OTC 2012 document provided an estimate of the capital cost range for retrofitting technologies to achieve the outlet NOx limit for each engine. An average cost based on the range was estimated for each engine and used in the current analysis. Details on the buildup of these costs are not provided in the OTC 2012 document. No annual costs are provided in the document. No emission reductions are provided in the document.

Based on the review of other references in this analysis, it was assumed that there are no additional annual operating costs incurred from the combustion modification technologies, except for annualized capital costs (CARB 2001). Because no emission reduction data were provided, an estimate of emissions was made in the current analysis. Uncontrolled NOx emissions were assumed to be 16.8 g/bhp-hr (EPA 2003), controlled emissions were 0.5 g/bhp-hr as stated in the reference, and the operating hours were assumed to be 2000 hr/yr (this assumption is consistent with the LEC operating hours in the CARB 2001 document).

Uncontrolled NOx emissions for the 3 similar sized engines ranged from 74 to 93 tpy, and the NOx reductions ranged from 72 to 90 tpy.

Based on the 3 make and model engines, the average cost was estimated to be $2,800,000 for approximately 2250 hp engines (average hp of the 3 units), and the average total annual cost was estimated to be $390,000. The average cost effectiveness is $4,900/ton of NOx reduction for 2000 hr/yr operation.

The cost year is not provided in the reference; we assumed the cost year is the date of the cited Cameron 2010 retrofit project, 2010$.

See the cost calculations in worksheet "Overall Sum—New Ref Review" of the Excel file, rows 21 through 25.

5.5 Layered Combustion (LC), Large Bore, 2 Stroke, Low Speed (NLCICE2SLBNG)

The costs and cost effectiveness for applying LC to natural gas Lean Burn engines (2 stroke Large Bore) are obtained from the document *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions* (OTC 2012). Large Bore RICE are those with large piston diameters. The larger the bore (or piston diameter), the larger the volume available for engine combustion, and hence the greater the power delivered by the engine. Information was provided on Capital costs; assumptions were made to determine Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-3 for LC for large bore 2 Stroke engines, along with changes in assumptions for the current analysis.

LC consists of multiple combustion modification technologies. The combustion modifications included (1) High pressure fuel injection; (2) Turbocharging, (3) Precombustion chamber, and (4) Cylinder head modifications (a discussion of individual technologies is provided on pp. 18 to 19 for 2 stroke Lean Burn engines). LC are known or demonstrated control techniques for lean burn, large bore, 2 stroke engines. These modifications achieved a NOx emissions rate of 0.5 g/bhp-hr. The OTC 2012 document provided ranges of capital costs for retrofitting combustion modifications for large bore 2 stroke Lean Burn engines from 200 to 11,000 hp (cited Cameron 2011 presentation "Available Emission Reduction Technology for Existing Large Bore Slow Speed Two Stroke Engines." A copy of this presentation was not found.). Details on the buildup of these costs are not provided in the OTC 2012 document. No annual costs are provided in the document. No emission reductions are provided in the document.

Based on the review of other references in this analysis, it was assumed that there are no additional annual operating costs incurred from the combustion modification technologies, except for annualized capital costs (CARB 2001). Because no emission reduction data were provided, an estimate of emissions was made in the current analysis. Uncontrolled NOx

Table 5-3. LC for Natural Gas Lean Burn Engines, Large Bore 2-stroke

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: Not provided.	Control efficiency: derived value is 97% (this is high)
Capital costs: based on cited Cameron 2010 project	None.
Annual Costs	
Equipment life: Not provided.	Equipment life: 10 yr
Interest rate: Not provided.	Interest rate: 7%
Operating hours: Not provided.	Operating hours: 2,000 hr/yr
Emission rate, uncontrolled: Not provided	Emission rate, uncontrolled: 16.8 g/bhp-hr
Emission rate, controlled: 0.5 g/bhp-hr	None.
Annualized equipment cost: Not provided.	CRF: 0.1424
Annual O&M cost: Not provided.	Annual O&M cost: $0.

emissions were assumed to be 16.8 g/bhp-hr (EPA 2003), controlled emissions were 0.5 g/bhp-hr as stated in the reference, and the operating hours were assumed to be 2000 hr/yr (this assumption is consistent with the LEC operating hours in the CARB 2001 document). Uncontrolled NOx emissions were estimated to be 410 tpy for the larger 11,000 hp engines and were estimated to be 7.4 tpy for the smaller 200 hp engines.

For the larger 11,000 hp engines, the current analysis shows a cost effectiveness of $1,500/ton of NOx reduction, and for the smaller 200 hp engines, the cost effectiveness is $38,000/ton of NOx reduction.

The cost year is not provided in the reference; assumed the cost year is the date of the cited Cameron 2010 retrofit project, 2010$.

See the cost calculations in worksheet “Overall Sum—New Ref Review” of the Excel file, rows 12 and 13.

5.6 Air to Fuel Ratio Controller (AFRC) (NAFRCICENG)

The costs and cost effectiveness for applying AFRC to natural gas Lean Burn engines are obtained from the document *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines* (CARB 2001). Information was provided on Capital costs; assumptions were made to determine Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-4 for AFRC, along with changes in assumptions for the current analysis.

Table 5-4. AFRC for Natural Gas Lean Burn Engines

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: not provided	Control efficiency: assumed 20%
Capital costs: provided for multiple models	None.
Annual Costs	
Equipment life: 10 yr	None.
Interest rate: 10%	Interest rate: 7%
Operating hours: 2000 hr/yr	None.
Emission rate, uncontrolled: 740 ppmv	Emission rate, uncontrolled: Assumed mid to upper end hp rating for each model.
Emission rate, controlled: 80% reduction	None.
Annualized equipment cost: provided for multiple model sizes	CRF: 0.1424
Annual O&M cost: assumed $0.	None.

AFRC are electronic engine controls that typically monitor engine parameters and atmospheric conditions to determine the correct air/fuel mixture for the operating condition, such as varying engine load or speed conditions, varying ambient conditions, or startup/shutdown conditions. (OTC 2012) (A discussion of individual technologies is provided in Appendix B of the original reference, CARB 2001, pp. B-1 to B-28). AFRC are known or demonstrated control techniques for lean burn engines. An 80 percent NOx emission reduction can be achieved by AFRC in combination with other combustion modifications, however a fuel consumption penalty of up to 3 percent can occur due to AFRC.

Capital were provided for multiple size ranges of engines. The capital costs ranged from $4,200 to $6,500 per engine.

No annual costs were provided in the document. No emissions reductions were provided in the document. Based on the cost analysis for other combustion technology controls in this document, it was assumed that there are no additional annual operating costs incurred from the combustion modification technologies, except for annualized capital costs (this assumption ignores the fuel penalty issue). The total annual costs ranged from $600 to $930. Because no emission reductions were provided in the document, an estimate of emissions was made in the current analysis. In the current analysis, a hp rating based on the middle or upper end of each size range was assumed for estimating the uncontrolled NOx emissions. Uncontrolled NOx emissions were estimated based on an uncontrolled NOx concentration of 740 ppmv (this equates to approximately 9 g/bhp-hr), the operating hours were assumed to be 2000 hr/yr (similar to the operating hours for other control technology analyses provided in the document), and controlled emissions were estimated based on an assumption of 20 percent reduction. Uncontrolled NOx emissions ranged from 1.1 to 34 tpy for the models, and the NOx reductions ranged from 0.22 to 6.7 tpy for the models.

The current analysis shows a cost effectiveness of $2,700/ton of NOx reduction to $140/ton for 2000 hr/yr operation, and the average cost effectiveness across all the models is $810/ton of NOx reduction.

The cost year is not provided in the reference; assumed the cost year is the date of the cited reference, 2001$.

Based on the cost calculations for engines of varying hp, the following equations were developed for the capital cost and annual costs for AFRC on natural gas Lean Burn engines:

$$\text{Capital cost} = 1.3007 \text{ x (hp)} + 4354.5$$

$$\text{Annual cost} = 0.1852 \text{ x (hp)} + 619.99$$

The R^2 value for these equations is 0.87. These equations should be included in the CoST database file under a new equation type.

See the cost calculations in worksheet “AFRC (CARB)-2001” of the Excel file.

5.7 SCR (for 4 Stroke Natural Gas Engines) (NSCRICE4SNG)

The costs and cost effectiveness for applying SCR to natural gas engines are obtained from the document *Appendix B, Cost Effectiveness Analysis for Rule 4702 (Internal Combustion*

Engines—Phase 2) (SJVAPCD 2003). Information was provided on Capital costs, Annual costs, uncontrolled emissions, and reduction efficiency. The assumptions for the original reference analysis are provided in Table 5-5 for SCR for natural gas engines along with changes in assumptions for the current analysis. SCR is a known or demonstrated control technique for lean burn engines, although multiple references indicate that the feasibility of SCR application for lean burn engines is highly site-specific.

Table 5-5. SCR for Natural Gas Lean Burn Engines, 4-stroke.

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: 90%	None.
Capital costs: based on RACT/BARCT Determination.	None.
Annual Costs	
Equipment life: 10 years	None.
Interest rate: 10%	Interest rate: 7%
Operating hours rate 1: 2190 hr/yr (equivalent to capacity factor of 0.25)	None.
Operating hours rate 2: 6570 hr/yr (equivalent to capacity factor of 0.75)	None.
Emission rate, uncontrolled: 740 ppmv NOx	None.
Emission rate, controlled: 65 ppmv NOx	None.
Annualized equipment cost: based on RACT/BARCT Determination.	None.
Annual O&M cost: based on RACT/BARCT Determination.	None.

The installed equipment capital cost ranged from $45,000 to $185,000 for 50 hp engines and 1500 hp engines, respectively. The total annual costs ranged from $27,000 for a 50 hp engine to $140,000 for a 1500 hp engine (these costs are very similar to the costs calculated in the original reference analysis; the only difference in annual costs is related to the CRF, i.e., changing the interest rate from 10 percent in the original reference analysis to 7 percent in the current analysis). NOx emissions are provided for two cases: a capacity factor of 0.25 (2190 hr/yr) and a capacity factor of 0.75 (6570 hr/yr). The uncontrolled NOx emissions ranged from 1.2 to 37 tpy for the lower capacity case, and the NOx reductions ranged from 1.1 to 33 tpy. For the higher capacity case, uncontrolled NOx emissions ranged from 3.7 to 110 tpy, and the NOx reductions achieved ranged from 3.3 to 100 tpy. The current analysis shows an average cost effectiveness of $8,700/ton of NOx reduction for 2190 hr/yr of operation, and $2,900/ton of NOx reduction for 6570 hr/yr operation (these cost effectiveness values are very similar to the costs shown in the original reference analysis).

Based on the cost calculations for engines of varying hp and annual capacity operating, the following linear equations were developed for the capital cost and annual costs for SCR on natural gas 4-stroke lean burn engines:

$$\text{Capital cost} = 107.1 \times (\text{hp}) + 27186$$

$$\text{Annual cost} = 83.64 \times (\text{hp}) + 14718$$

The R^2 values for these equations are 0.95 for capital cost and 0.98 for annual cost. These equations should be included in the CoST database file under a new equation type for linear equations.

The cost year is not provided in the reference; assumed the cost year is the date of the cost-basis document, 2001$.

See the cost calculations in worksheet "SCR NG (SJVAPCD)-2003" of the Excel file. [Other cost effectiveness values for SCR are available from the PA DEP that are higher than the cost effectiveness values shown for the SJVAPCD SCR analysis, and other analyses. See the summary of SCR costs in worksheet "Other SCR Cost Info" of the Excel file.]

5.8 SCR (for Diesel Engines) (NSCRICEDS)

The costs and cost effectiveness for applying SCR to diesel lean burn engines is provided in *Alternative Control Techniques Document: Stationary Diesel Engines* (EPA 2010). The assumptions for the original reference analysis are provided in Table 5-6 for SCR for diesel engines, along with changes in assumptions for the current analysis. SCR is a known or demonstrated control technique for lean burn, diesel engines.

Approximately 76 percent of the population of stationary diesel engines is less than 300 hp and the remaining 24 percent is greater than 300 hp. Applications for stationary engines under 300 hp include standby power generation, agriculture, and industrial applications, and less than 5 percent are used for continuous power generation. Applications for stationary engines greater than 300 hp are primarily power generation and are almost evenly divided between continuous duty and standby applications.

The cost analysis provided in the original reference includes an assumption that stationary diesel lean burn engines operate approximately 1000 hr/yr. This assumption is likely appropriate for the majority of those units that are less than 300 hp and for half of the diesel engines greater than 300 hp, i.e., approximately 87 percent of diesel lean burn engines (this ignores the "fewer than 5 percent" used for continuous power generation). For the remaining 13 percent of engines that are greater than 300 hp and used in continuous power generation applications, an assumption for longer operating hours, such as 8000 hr/yr, may be needed to estimate the cost effectiveness.

Table 5-6. SCR for Diesel Lean Burn Engines—Assumptions

Assumptions in Original Reference	Changes to Assumptions Made in Current Analysis
Capital costs	
Control efficiency: 90 %	None.
Equipment life: 15 year	None.
Interest rate: 7%	None.
Capital costs: $98/hp	None.
Annual Costs	
Operating hours: 1000 hr/yr	None.
Annual costs: $40/hp (based on 1000 hr/yr operation; already includes Capital Recovery)	None.

The original reference analysis provided a capital cost of $98/hp, and based on the mid-range hp rating for four model engines, the capital costs ranged from $7,300 to $98,000 for SCR. The original reference analysis provided an annual cost of $40/hp, and the annual costs ranged from $3,000 to $40,000 per year. Uncontrolled NOx emissions factors in the original reference were based on Tier 0 to Tier 3 values[1] and an assumption of 1000 hr/yr operation. Uncontrolled NOx emissions range from 0.25 to 9.2 tpy across the four models, and the NOx reductions ranged from 0.22 to 8.3 tpy.

The current analysis shows an average cost effectiveness of $9,300/ton of NOx reduction for 1000 hr/yr of operation (no weighting to the average based on engine age was applied). The cost effectiveness over the engine size range varied from $4,800/ton to $16,000/ton for diesel engines (and are very similar to the costs shown in the original reference analysis). It is

[1] Federal Standards, from the *Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling—Compression Ignition*. EPA Publication No. EPA420-P-04_009. April 2004.

important to note that the cost effectiveness is correlated to the manufacturing year of the diesel engine, i.e., the Tier limit for NOx emissions. Older engines manufactured prior to 1998 have the most lenient emissions limit while later model years have more stringent NOx emission limits (lower baseline emissions). The overall magnitude of emission reduction achieved by the SCR is lower for later model years as compared to earlier years, and therefore, the cost effectiveness values are higher for later model years.

[Note: This analysis shows emission reductions and cost effectiveness for existing and new diesel engines through approximately 2011, the last year for phase in of the Tiered emission values. The original reference provided information (circa 2005) on the age of the stationary engine population, with approximately 57 percent of engines at that time being manufactured prior to 1994 and approximately 42 percent manufactured after 1994 (note that the grouping of the age data does not align well with the Tier years, in that the age data shows breaks in 1994 and 2003 while the Tier ranges show breaks in 1996, 1998, 2002, 2003, etc.). As the diesel engine population continues to age and older engines are retired (i.e., those diesel engines subject to the Pre-1998 and the Tier 1 (1998 to 2003) or Tier 1 (1996 to 2001), etc. and are replaced with newer engines achieving lower NOx baseline emissions, the cost effectiveness for new engines would tend to be in the higher end shown for each model and would contribute to a somewhat higher average cost-effectiveness value. The average cost effectiveness will likely move toward the $13,000/ton to $16,000/ton of NOx reduction range.]

See the cost calculations in worksheet "SCR Diesel (EPA Dies ACT)-2010" of the Excel file.

5.9 Applicable SCCs for Lean Burn Engine Control Measures

Table 5-7 lists all of the ICE SCCs that are associated with one or more gas lean burn ICR control measures in the CMDB table called "Table 03_SCCs." These SCCs were identified with NOx emissions in an EPA query of the NEI for facilities in the Ozone Transport Group Assessment Region (i.e., 37 states that are partially or completely to the east of 100oW longitude). The control measures shown in the column headings in Table 5-7 are the ICE control measures that are currently in the CMDB. Each control measure that was determined to be applicable for a specific SCC is identified with an "N" in the cell, meaning the control measure is "new," i.e., not currently linked to this particular SCC, but we recommend adding this link in the database. In some cases, we recommend applying new links between existing control measures and existing SCCs. For example, some of the SCCs are for ICE that are fired with relatively uncommon fuels such as process gas, methanol, digester gas, or landfill gas. While we have not

Table 5-7. Potential Reciprocating Engine SCCs to Add to the CMDB and Applicable Control Measures

SCC[a]	SCC Level 1[b]	SCC Level 2[c]	SCC Level 3	SCC Level 4	Applicable Control Measures for the Reciprocating Engine SCC[d]										
					NAFRICGS	NAFRIICGS	NIRICGD	NIRICGS	NIRICOL	NIRRICOIL	NSCRICGD	NSCRICGS	NSCRICOL	NSCRRICOIL	NSNCRICGS
20200702	ICE	Ind	Process Gas	Reciprocating Engine	N	N		N				N			N
20200712	ICE	Ind	Process Gas	Reciprocating: Exhaust	N	N		N				N			N
20201602	ICE	Ind	Methanol	Reciprocating Engine			N				N				
20201607	ICE	Ind	Methanol	Reciprocating: Exhaust			N				N				
20201702	ICE	Ind	Gasoline	Reciprocating Engine			N				N				
20201707	ICE	Ind	Gasoline	Reciprocating: Exhaust			N				N				
20280001	ICE	Ind	Equipment Leaks	Equipment Leaks											
20282001	ICE	Ind	Wastewater, Aggregate	Process Area Drains											
20300702	ICE	C/I	Digester Gas	Reciprocating: POTW Digester Gas	N	N		N				N			N
20300707	ICE	C/I	Digester Gas	Reciprocating: Exhaust	N	N		N				N			N
20300802	ICE	C/I	Landfill Gas	Reciprocating	N	N		N				N			N
20400401	ICE	ET	Reciprocating Engine	Gasoline			N				N				
20400402	ICE	ET	Reciprocating Engine	Diesel/Kerosene			N		N	N	N		N	N	
20400404	ICE	ET	Reciprocating Engine	Process Gas	N	N		N							N
20400406	ICE	ET	Reciprocating Engine	Kerosene/Naphtha (Jet Fuel)			N				N				
20400409	ICE	ET	Reciprocating Engine	Liquified Petroleum Gas (LPG)			N				N				

[a]SCCs represent reciprocating engine activities that were identified with NOx emissions in the Ozone Transport Assessment Group Region analysis but are not associated with reciprocating engine control measures in the current CMDB.

[b]ICE means "Internal Combustion Engines."

[c]Ind means "Industrial," C/I means "Commercial/Institutional," and ET means "Engine Testing."

[d]The control measure is assumed to be representative for the SCC; control cost data are unavailable for the specific fuel type for the SCC.

located any analyses that determined the applicable controls and related costs for ICE fired with such fuels, similar control measures can be assigned to these SCCs. In order to conduct CoST modeling analyses for these ICE, the most representative available control measures could be assigned. For ICE that burn miscellaneous gaseous fuels, the most representative control measures are those for natural gas-fired ICE. Similarly, for ICE that burn miscellaneous liquid fuels such as methanol, gasoline, kerosene/diesel, and LPG, the most representative available control measures are those for gas- or diesel-fired ICE. Also, for ICE that burn liquid fuels such as diesel/kerosene, the most representative available control measures are those for gas-, diesel-, or oil-fired ICE.

Six new control measures have been added to the CMDB for lean burn engines under this review and these control measures are described in Sections 5.3 through 5.8 of this report. Table 5-8 lists those SCCs that should be associated with the newly added lean burn engine control measures. Each control measure that was determined to be applicable for a specific SCC is identified by a "Y," which means yes.

In Table 5-9, a number of recommendations were made to delete NOx control measure/SCC combinations from the CMDB. ICE SCCs for evaporative losses from fuel storage and delivery systems are incorrectly associated with NOx control measures in the current CMDB, and we recommend deleting these all NOx control measure/SCC records from the CMDB table called "Table 03_SCCs" because there should be no NOx emissions from the sources represented by these SCCs. In addition, multiple ICE control measures are misassigned to turbine SCCs and we recommend deleting these NOx control measure/SCC records. The reverse issue also exists where multiple turbine control measures are misassigned to ICE SCCs, and we recommend deleting these NOx control measure/SCC records, as well. These control measure/SCC combinations are identified in Table 5-9.

5.10 Pennsylvania General Permit 5 (GP-5) for Natural Gas Compression and/or Processing Facilities

Pennsylvania DEP recently released a general permit for Natural Gas Compression and/or Processing Facilities that includes limits on NOx emissions from ICE. NOx emission limits from this general permit, along with other NOx limits for Pennsylvania, are shown in Table 5-10. Typical emission rates and the cost-effectiveness values for applying certain control measures are shown for lean burn and rich burn engines in Table 5-11.

Table 5-8. Recommended New Control Measures to Associate With Lean Burn Reciprocating Engine SCCs in the CMDB

					Applicable Control Measures for the Lean Burn Reciprocating Engine SCC					
SCC[a]	SCC Level 1	SCC Level 2	SCC Level 3	SCC Level 4	NLECICENG	NLCICE2SNG	NLCICE2SLBNG	NAFRCICENG	NSCRICE4SNG	NSCRICEDS
20200102	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating						Y
20200107	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating: Exhaust						Y
20200252	Internal Combustion Engines	Industrial	Natural Gas	2-cycle Lean Burn	Y	Y	Y	Y	Y	
20200254	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Lean Burn	Y	Y	Y	Y	Y	
20200255	Internal Combustion Engines	Industrial	Natural Gas	2-cycle Clean Burn	Y	Y	Y	Y	Y	
20200256	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Clean Burn	Y	Y	Y	Y	Y	
20200401[b]	Internal Combustion Engines	Industrial	Large Bore Engine	Diesel			Y			
20200402[b]	Internal Combustion Engines	Industrial	Large Bore Engine	Dual Fuel (Oil/Gas)			Y			
20200403[b]	Internal Combustion Engines	Industrial	Large Bore Engine	Cogeneration: Dual Fuel			Y			

[a]SCCs represent reciprocating engine activities that were identified with NOx emissions in the recent Ozone Transport Region analysis but are not associated with reciprocating engine control measures in the current CMDB.

[b]The control measure is assumed to be representative for the SCC; control cost data are unavailable for the specific fuel type for the SCC.

Table 5-9. Recommended Control Measure Deletions From SCCs in the CMDB

SCC	SCC Level 1	SCC Level 2	SCC Level 3	SCC Level 4	Control Measures Recommended for Deletion
20200106	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating: Evap Losses	All NOx control measures
20200206	Internal Combustion Engines	Industrial	Natural Gas	Reciprocating: Evap Losses	All NOx control measures
20200306	Internal Combustion Engines	Industrial	Gasoline	Reciprocating: Evap Losses	All NOx control measures
20200406	Internal Combustion Engines	Industrial	Large Bore Engine	Reciprocating: Evap Losses	All NOx control measures
20200506	Internal Combustion Engines	Industrial	Residual/Crude Oil	Reciprocating: Evap Losses	All NOx control measures
20200906	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Reciprocating: Evap Losses	All NOx control measures
20201006	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Reciprocating: Evap Losses	All NOx control measures
20300106	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Reciprocating: Evap Losses	All NOx control measures
20300206	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Reciprocating: Evap Losses	All NOx control measures
20300306	Internal Combustion Engines	Commercial/Institutional	Gasoline	Reciprocating: Evap Losses	All NOx control measures
20301006	Internal Combustion Engines	Commercial/Institutional	Liquified Petroleum Gas (LPG)	Reciprocating: Evap Losses	All NOx control measures
20200108	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Turbine: Evap Losses	All NOx control measures
20200109	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Turbine: Exhaust	NNSCRRBIC
20200208	Internal Combustion Engines	Industrial	Natural Gas	Turbine: Evap Losses	All NOx control measures
20200209	Internal Combustion Engines	Industrial	Natural Gas	Turbine: Exhaust	NNSCRRBIC2
20200908	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Turbine: Evap Losses	All NOx control measures
20200909	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Turbine: Exhaust	NNSCRRBGD

(continued)

Table 5-9. Recommended Control Measure Deletions From SCCs in the CMDB (continued)

SCC	SCC Level 1	SCC Level 2	SCC Level 3	SCC Level 4	Control Measures Recommended for Deletion
20201008	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Turbine: Evap Losses	All NOx control measures
20201009	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Turbine: Exhaust	NNSCRRBGD
20201011	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Turbine	NNSCRRBGD
20201013	Internal Combustion Engines	Industrial	Liquified Petroleum Gas (LPG)	Turbine: Cogeneration	NNSCRRBGD
20300108	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Turbine: Evap Losses	All NOx control measures
20300109	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Turbine: Exhaust	NNSCRRBIC
20300208	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Turbine: Evap Losses	All NOx control measures
20300209	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Turbine: Exhaust	NNSCRRBIC2
20200105	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating: Crankcase Blowby	NNSCRWGTOL, NWTINGTOL
20200107	Internal Combustion Engines	Industrial	Distillate Oil (Diesel)	Reciprocating: Exhaust	NSCRWGTOL, NWTINGTOL
20200205	Internal Combustion Engines	Industrial	Natural Gas	Reciprocating: Crankcase Blowby	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200207	Internal Combustion Engines	Industrial	Natural Gas	Reciprocating: Exhaust	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200252	Internal Combustion Engines	Industrial	Natural Gas	2-cycle Lean Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200253	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Rich Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200254	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Lean Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200255	Internal Combustion Engines	Industrial	Natural Gas	2-cycle Clean Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG

(continued)

Table 5-9. Recommended Control Measure Deletions From SCCs in the CMDB (continued)

SCC	SCC Level 1	SCC Level 2	SCC Level 3	SCC Level 4	Control Measures Recommended for Deletion
20200256	Internal Combustion Engines	Industrial	Natural Gas	4-cycle Clean Burn	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20200905	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Reciprocating: Crankcase Blowby	NSCRWGTJF, NWTINGTJF
20200907	Internal Combustion Engines	Industrial	Kerosene/Naphtha (Jet Fuel)	Reciprocating: Exhaust	NSCRWGTJF, NWTINGTJF
20300105	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Reciprocating: Crankcase Blowby	NNSCRWGTOL, NWTINGTOL
20300107	Internal Combustion Engines	Commercial/Institutional	Distillate Oil (Diesel)	Reciprocating: Exhaust	NSCRWGTOL, NWTINGTOL
20300205	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Reciprocating: Crankcase Blowby	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG
20300207	Internal Combustion Engines	Commercial/Institutional	Natural Gas	Reciprocating: Exhaust	NLNBUGTNG, NSCRLGTNG, NSCRSGTNG, NSCRWGTNG, NSTINGTNG, NWTINGTNG

Table 5-10. NOx Control Requirements for RICE in Pennsylvania

State	Source Category Covered	NOx Control Level	Reference
Pennsylvania	153 ton NOx/season	≥2400 hp: 3 g/bhp-hr (220 ppm)	IEPA 2007
Pennsylvania (proposed values) [Assume proposal was 2011Mar26]	General Permit—Natural Gas Production and Processing Facility, SI, ICE	Existing LB or RB, 100 to 1500 hp: 2 g/bhp-hr New, Reconfigured, LB ≤100 hp: 2 g/bhp-hr New, Reconfigured, LB 100 to 637 hp: 1 g/bhp-hr New, Reconfigured, LB >637 hp: 0.5 g/bhp-hr	OTC 2012
Pennsylvania (amended 2013Feb02)	Natural Gas Compression and Processing, NG, SI, ICE, includes facilities with actual or potential emissions <100 tpy NOx, and <25 tpy NOx in 5 counties.	New, Reconfigured LB or RB, ≤100 hp: 2 g/bhp-hr New, Reconfigured LB, 100 to 500 hp: 1 g/bhp-hr New, Reconfigured LB, >500 hp: 0.5 g/bhp-hr New, Reconfigured RB, 100 to 500 hp: 0.25 g/bhp-hr New, Reconfigured RB, >500 hp: 0.2 g/bhp-hr	PA DEP 2013
Pennsylvania	Interstate Pollution Transport Reduction, Emission of NOx from Stationary ICE	LB, >2400 hp: 3.0 g/bhp-hr RICE, RB, >2400 hp: 1.5 g/bhp-hr	DE 2012

Table 5-11. Characteristics of NOx Emissions and Controls for RICE

Engine Type and Size	Uncontrolled Emissions	Emissions	Cost Effectiveness for NOx Reductions	Reference
Lean burn				
LB >500 hp	NA	SCR, stack test, 0.22 to 0.50 g/bhp-hr	SCR: $71,000 to $60,000/ton (for 500 to 4000 hp)	PA DEP 2013, p. 22
LB 100 to 500 hp	1 to 16.4 g/bhp-hr	NA	SCR: >$42,000/ton	PA DEP 2013, p. 20
LB <100 hp	2 g/bhp-hr	2 g/bhp-hr	SCR: >$48,000/ton	PA DEP 2013, p. 17
Rich burn				
RB >500 hp	13 to 16 g/bhp-hr	NSCR: stack test, 0.02 to 0.14 g/bhp-hr	NA	PA DEP 2013, p. 28, 29
RB 100 to 500 hp	13 to 16.4 g/bhp-hr.	NA	NSCR: $177/ton	PA DEP 2013, p. 25, 26
RB <100 hp	11.41 to 21.08 g/bhp-hr	NSCR: <2 g/bhp-hr, at least 90% reduction	NSCR: <$650/ton for 100 hp NSCR: <$1200/ton for 50 hp	PA DEP 2013, p. 17

APPENDIX A
AMMONIA REFORMERS

Copies of database tables showing all records for ammonia reformer controls, highlighting revisions.

Table A-1. CMDB Table 06 References (New)

Data Source	Description
AR-1	Indian Nations Council of Governments (INCOG), 2008: Indian Nations Council of Governments (INCOG), "Tulsa Metropolitan Area 8-Hour Ozone Flex Plan: 2008 8-O3 Flex Program," March 6, 2008. Downloaded from http://www.epa.gov/ozoneadvance/pdfs/Flex-Tulsa.pdf

Table A-2. CMDB Table 01 Summary

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Nei Device Code	Date Reviewed	Data Source	Months	Description
Low NOx Burner; Ammonia—NG-Fired Reformers	NLNBUFRNG	N0561	NOx	Low NOx Burner	Ammonia—NG-Fired Reformers	ptnonipm	Known	10	204|205	2013	AR-1 |186		Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to small (<1 ton NOx per OSD) ammonia production operations with natural gas-fired reformers (SCC 30100306) and uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to “stage” combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner and Flue Gas Recirculation; Ammonia—NG-Fired Reformers	NLNBFFRNG	N0562	NOx	Low NOx Burner and Flue Gas Recirculation	Ammonia—NG-Fired Reformers	ptnonipm	Known	10		2006	72|172|175|179|186		Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to small (<1 ton NOx per OSD) ammonia production operations with natural gas-fired reformers (SCC 30100306) and uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to “stage” combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner and Flue Gas Recirculation; Ammonia—Oil-Fired Reformers	NLNBFFROL	N0572	NOx	Low NOx Burner and Flue Gas Recirculation	Ammonia—Oil-Fired Reformers	ptnonipm	Known	10		2006	72		Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to ammonia production operations with oil-fired reformers (SCC 30100307). Discussion: LNBs are designed to “stage” combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner and Flue Gas Recirculation; Ammonia Prod; Feedstock Desulfurization	NLNBFAPFD	N0622	NOx	Low NOx Burner and Flue Gas Recirculation	Ammonia Prod; Feedstock Desulfurization	ptnonipm	Known	10		2006	72|172|175|179|185		Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to small (<1 ton per OSD) feedstock desulfurization processes in ammonia products operations (SCC 30100305) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: It is assumed that the superheated steam needed to regenerate the activated carbon bed used in the desulfurization process is the NOx source. LNBs are designed to “stage” combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Oxygen Trim and Water Injection; Ammonia—NG-Fired Reformers	NOTWIFRNG	N0563	NOx	Oxygen Trim and Water Injection	Ammonia—NG-Fired Reformers	ptnonipm	Known	10		2006	72|172|175|179|184|185		Application: This control is the use of OT + WI to reduce NOx emissions This control is applicable to small (<1 ton NOx per OSD) ammonia production operations with natural gas-fired reformers (SCC 30100306) and uncontrolled NOx emissions greater than 10 tons per year. This control is also applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).

(continued)

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Table A-2. CMDB Table 01 Summary (continued)

<table>
<tr><th>cmname</th><th>Cm Abbreviation</th><th>Pechan Meas Code</th><th>Major Poll</th><th>Control Technology</th><th>Source Group</th><th>Sector</th><th>Class</th><th>Equip Life</th><th>Nei Device Code</th><th>Date Reviewed</th><th>Data Source</th><th>Months</th><th>Description</th></tr>
<tr><td>Selective Catalytic Reduction; Ammonia—NG-Fired Reformers</td><td>NSCRFRNG</td><td>N0564</td><td>NOx</td><td>Selective Catalytic Reduction</td><td>Ammonia—NG-Fired Reformers</td><td>ptnonipm</td><td>Known</td><td>20</td><td>139</td><td>2006</td><td>72|167|175|179|224|225|226</td><td></td><td>Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures.

Applies to natural-gas fired reformers involved in the production of ammonia (SCC 30100306) with uncontrolled NOx emissions greater than 10 tons per year.

Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002).

Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx.

The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required.

The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water.</td></tr>
<tr><td>Selective Catalytic Reduction; Ammonia—Oil-Fired Reformers</td><td>NSCRFROL</td><td>N0573</td><td>NOx</td><td>Selective Catalytic Reduction</td><td>Ammonia—Oil-Fired Reformers</td><td>ptnonipm</td><td>Known</td><td>20</td><td>139</td><td>2006</td><td>72</td><td></td><td>Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures.

Applies to natural-gas fired reformers involved in the production of ammonia (SCC 30100306) with uncontrolled NOx emissions greater than 10 tons per year.

Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002).

Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx.

The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required.

The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water.

Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002).

The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).</td></tr>
</table>

(continued)

Table A-2. CMDB Table 01 Summary (continued)

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Nei Device Code	Date Reviewed	Data Source	Months	Description
Selective Non-Catalytic Reduction—Ammonia; NG-Fired Reformers	NSNCRFRNG	N0565	NOx	Selective Non-Catalytic Reduction	Ammonia—NG-Fired Reformers	ptnonipm	Known	20	107	2006	72|172|175|179|185		Application: This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to small (<1 ton NOx per OSD) ammonia production natural gas fired reformers (SCC 30100306) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: SNCR is the reduction of NOx in flue gas to N2 and water vapor. This reduction is done with a nitrogen based reducing reagent, such as ammonia or urea. The reagent can react with a number of flue gas components. However, the NOx reduction reaction is favored for a specific temperature range and in the presence of oxygen (EPA, 2002). Both ammonia and urea are used as reagents. The cost of the reagent represents a large part of the annual costs of an SNCR system. Ammonia is generally less expensive than urea. However, the choice of reagent is also based on physical properties and operational considerations (EPA, 2002). Ammonia can be utilized in either aqueous or anhydrous form. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Urea based systems have several advantages, including several safety aspects. Urea is a nontoxic, less volatile liquid that can be stored and handled more safely than ammonia. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing mixing (EPA, 2002). Because of these advantages, urea is more commonly used than ammonia in large boiler applications.
Low NOx Burner; Ammonia—Oil-Fired Reformers	NLNBUFROL	N0571	NOx	Low NOx Burner	Ammonia—Oil-Fired Reformers	ptnonipm	Known	10	204|205	2006	72		Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to ammonia production operations with oil-fired reformers (SCC 30100307). Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Selective Non-Catalytic Reduction—Ammonia; Oil-Fired Reformers	NSNCRFROL	N0574	NOx	Selective Non-Catalytic Reduction	Ammonia—Oil-Fired Reformers	ptnonipm	Known	20	107	2006	72		Application: This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to ammonia production natural gas fired reformers (SCC 30100306) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: SNCR is the reduction of NOx in flue gas to N2 and water vapor. This reduction is done with a nitrogen based reducing reagent, such as ammonia or urea. The reagent can react with a number of flue gas components. However, the NOx reduction reaction is favored for a specific temperature range and in the presence of oxygen (EPA, 2002). Both ammonia and urea are used as reagents. The cost of the reagent represents a large part of the annual costs of an SNCR system. Ammonia is generally less expensive than urea. However, the choice of reagent is also based on physical properties and operational considerations (EPA, 2002). Ammonia can be utilized in either aqueous or anhydrous form. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Urea based systems have several advantages, including several safety aspects. Urea is a nontoxic, less volatile liquid that can be stored and handled more safely than ammonia. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing mixing (EPA, 2002). Because of these advantages, urea is more commonly used than ammonia in large boiler applications.

(continued)

Table A-2. CMDB Table 01 Summary (continued)

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Nei Device Code	Date Reviewed	Data Source	Months	Description
Low NOx Burner; Ammonia Production; Other Not Classified	NLNBUAONC		NOx	Low NOx Burner	Ammonia Production—Other Not Classified	ptnonipm	Known	10	204|205	2013	AR-1|186		Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: LNBs are designed to “stage” combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002)
Low NOx Burner and Flue Gas Recirculation; Ammonia Production; Other Not Classified	NLNBFAONC		NOx	Low NOx Burner and Flue Gas Recirculation	Ammonia Production—Other Not Classified	ptnonipm	Known	10		2013	72|172|175|179|186		Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: LNBs are designed to “stage” combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Selective Non-Catalytic Reduction—Ammonia; Ammonia Production; Other Not Classified	NSNCRAONC		NOx	Selective Non-Catalytic Reduction	Ammonia Production—Other Not Classified	ptnonipm	Known	20	107	2013	72|172|175|179|185		Application: This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: SNCR is the reduction of NOx in flue gas to N2 and water vapor. This reduction is done with a nitrogen based reducing reagent, such as ammonia or urea. The reagent can react with a number of flue gas components. However, the NOx reduction reaction is favored for a specific temperature range and in the presence of oxygen (EPA, 2002). Both ammonia and urea are used as reagents. The cost of the reagent represents a large part of the annual costs of an SNCR system. Ammonia is generally less expensive than urea. However, the choice of reagent is also based on physical properties and operational considerations (EPA, 2002). Ammonia can be utilized in either aqueous or anhydrous form. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Urea based systems have several advantages, including several safety aspects. Urea is a nontoxic, less volatile liquid that can be stored and handled more safely than ammonia. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing mixing (EPA, 2002). Because of these advantages, urea is more commonly used than ammonia in large boiler applications.
Oxygen Trim and Water Injection; Ammonia Production; Other Not Classified	NOTWIAONC		NOx	Oxygen Trim and Water Injection	Ammonia Production—Other Not Classified	ptnonipm	Known	10		2013	72|172|175|179|184|185		Application: This control is the use of OT + WI to reduce NOx emissions This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).

(continued)

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Table A-2.   CMDB Table 01 Summary (continued)

cmname	Cm Abbreviation	Pechan Meas Code	Major Poll	Control Technology	Source Group	Sector	Class	Equip Life	Nei Device Code	Date Reviewed	Data Source	Months	Description
Selective Catalytic Reduction; Ammonia Production; Other Not Classified	NSCRAONC		NOx	Selective Catalytic Reduction	Ammonia Production—Other Not Classified	ptnonipm	Known	20	139	2013	72|167|175|179|224|225|226		Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to miscellaneous combustion emissions from ammonia production operations (SCC 30100399). Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water.

Table A-3. CMDB Table 02 Efficiencies

cmabbreviation	Pollutant	Locale	Effective Date	existingmeasureabbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equationtype	caprecfactor	discountrate	capannratio	incrementalcpt	Details
NLNBFAPFD	NOx				0	0	365	60	1990	2560	100	100	cpton	0.1424		5.9	2470	Applied to small source types
NLNBFAPFD	NOx				0	365		60	1990	590	100	100	cpton	0.1424		7.5	280	Applied to large source types
NLNBFFRNG	NOx				0	0	365	60	1990	2560	100	100	cpton	0.1424		5.9	2470	Applied to small source types
NLNBFFRNG	NOx				0	365		60	1990	590	100	100	cpton	0.1424		7.5	280	Applied to large source types
NLNBFFROL	NOx				0	0	365	60	1990	1120	100	100	cpton	0.1424		5.9	1080	Applied to small source types
NLNBFFROL	NOx				0	365		60	1990	390	100	100	cpton	0.1424		7.5	190	Applied to large source types
NLNBUFROL	NOx				0	0	365	50	1990	400	100	100	cpton	0.1424		5.5		Applied to small source types
NLNBUFROL	NOx				0	365		50	1990	430	100	100	cpton	0.1424		5.5		Applied to large source types
NOTWIFRNG	NOx				0	0	365	65	1990	680	100	100	cpton	0.1424		2.9		Applied to small source types
NOTWIFRNG	NOx				0	365		65	1990	320	100	100	cpton	0.1424		2.9		Applied to large source types
NSCRFRNG	NOx				0	0	365	90	1999	2366	100	100	cpton	0.0944		10		Applied to small source types
NSCRFRNG	NOx				0	365		90	1999	2366	100	100	cpton	0.0944		9.6		Applied to large source types
NSCRFROL	NOx				0	0	365	80	1990	1480	100	100	cpton	0.0944		10	1910	Applied to small source types
NSCRFROL	NOx				0	365		80	1990	810	100	100	cpton	0.0944		9.6	940	Applied to large source types
NSNCRFRNG	NOx				0	0	365	50	1990	3870	100	100	cpton	0.0944		9.4	2900	Applied to small source types
NSNCRFRNG	NOx				0	365		50	1990	1570	100	100	cpton	0.0944		8.2	840	Applied to large source types
NSNCRFROL	NOx				0	0	365	50	1990	2580	100	100	cpton	0.0944		9.4	1940	Applied to small source types
NSNCRFROL	NOx				0	365		50	1990	1050	100	100	cpton	0.0944		8.2	560	Applied to large source types
NLNBUFRNG	NOx				0	0	365	50	1990	820	100	100	cpton	0.1424		5.5		Applied to small source types; *no new information was available for small sources during 2013 update*
NLNBUFRNG	NOx				0	365		50	*2008*	*800*	100	100	cpton	0.1424		*5.9*		Applied to large source types; *equipment life of 10 years and 7% interest*

APPENDIX B
COMBUSTION TURBINES

Copies of the database tables for showing all records for Combustion Turbines NOx controls are provided. Changes are highlighted in red font.

– Table B-1. CMDB Table 01_Summary

– Table B-2. CMDB Table 02_Efficiencies

– Table B-3. CMDB Table 04_Equations

– Table B-4. Additional CMDB Table 06_References

Table B-1. CMDB Table 01_Summary

<table>
<tr><th>cmname</th><th>cmabbreviation</th><th>pechanmeascode</th><th>majorpoll</th><th>controltechnology</th><th>sourcegroup</th><th>sector</th><th>class</th><th>equiplife</th><th>neidevicecode</th><th>datereviewed</th><th>datasource</th><th>months</th></tr>
<tr><td>Dry Low NOx Combustion; Gas Turbines—Natural Gas</td><td>NDLNCGTNG</td><td>N0243</td><td>NOx</td><td>Dry Low NOx Combustion</td><td>Gas Turbines—Natural Gas</td><td>ptnonipm</td><td>Known</td><td>15</td><td>204|205</td><td>2013</td><td>72|172|175|179|223|CT-2|CT-6</td><td></td></tr>
<tr><td>SCR + Dry Low NOx Combustion; Gas Turbines—Natural Gas</td><td>NSCRDGTNG</td><td>N0244</td><td>NOx</td><td>SCR + DLN Combustion</td><td>Gas Turbines—Natural Gas</td><td>ptnonipm</td><td>Known</td><td>15</td><td></td><td>2013</td><td>72|172|175|179|223|224|CT-2|CT-3|CT-4|CT-6|CT-8</td><td></td></tr>
<tr><td>Selective Catalytic Reduction and Steam Injecti; Gas Turbines—Natural Gas</td><td>NSCRSGTNG</td><td>N0245</td><td>NOx</td><td>Selective Catalytic Reduction and Steam Injection</td><td>Gas Turbines—Natural Gas</td><td>ptnonipm</td><td>Known</td><td>15</td><td></td><td>2013</td><td>72|172|175|179|223|224|CT-2|CT-3</td><td></td></tr>
<tr><td>Selective Catalytic Reduction and Water Injecti; Gas Turbines—Jet Fuel</td><td>NSCRWGTJF</td><td>N0502</td><td>NOx</td><td>Selective Catalytic Reduction and Water Injection</td><td>Gas Turbines—Jet Fuel</td><td>ptnonipm</td><td>Known</td><td>15</td><td></td><td>2013</td><td>72|172|175|179|223|CT-2|CT-7</td><td></td></tr>
<tr><td>Selective Catalytic Reduction and Water Injecti; Gas Turbines—Natural Gas</td><td>NSCRWGTNG</td><td>N0246</td><td>NOx</td><td>Selective Catalytic Reduction and Water Injection</td><td>Gas Turbines—Natural Gas</td><td>ptnonipm</td><td>Known</td><td>15</td><td></td><td>2013</td><td>72|172|175|179|223|224|CT-2|CT-3|CT-8</td><td></td></tr>
<tr><td>Selective Catalytic Reduction and Water Injecti; Gas Turbines—Oil</td><td>NSCRWGTOL</td><td>N0232</td><td>NOx</td><td>Selective Catalytic Reduction and Water Injection</td><td>Gas Turbines—Oil</td><td>ptnonipm</td><td>Known</td><td>15</td><td></td><td>2013</td><td>72|172|175|179|223|224|CT-2|CT-7</td><td></td></tr>
<tr><td>Steam Injection; Gas Turbines—Natural Gas</td><td>NSTINGTNG</td><td>N0242</td><td>NOx</td><td>Steam Injection</td><td>Gas Turbines—Natural Gas</td><td>ptnonipm</td><td>Known</td><td>15</td><td></td><td>2013</td><td>72|172|175|184|223|CT-2</td><td></td></tr>
<tr><td>Water Injection; Gas Turbines—Jet Fuel</td><td>NWTINGTJF</td><td>N0501</td><td>NOx</td><td>Water Injection</td><td>Gas Turbines—Jet Fuel</td><td>ptnonipm</td><td>Known</td><td>15</td><td></td><td>2013</td><td>72|172|175|184|223|CT-2</td><td></td></tr>
<tr><td>Water Injection; Gas Turbines—Natural Gas</td><td>NWTINGTNG</td><td>N0241</td><td>NOx</td><td>Water Injection</td><td>Gas Turbines—Natural Gas</td><td>ptnonipm</td><td>Known</td><td>15</td><td></td><td>2013</td><td>72|172|175|184|223|CT-2</td><td></td></tr>
<tr><td>Water Injection; Gas Turbines—Oil</td><td>NWTINGTOL</td><td>N0231</td><td>NOx</td><td>Water Injection</td><td>Gas Turbines—Oil</td><td>ptnonipm</td><td>Known</td><td>15</td><td></td><td>2013</td><td>72|172|175|184|223|CT-2</td><td></td></tr>
<tr><td>Catalytic Combustion; Gas Turbine—Natural Gas</td><td>NCATCGTNG</td><td>N/A</td><td>NOx</td><td>Catalytic Combustion</td><td>Gas Turbines—Natural Gas</td><td>ptnonipm</td><td>Emerging</td><td>15</td><td></td><td>2013</td><td>CT-1|CT-2</td><td></td></tr>
<tr><td>EMx and Dry Low NOx Combustion; Gas Turbines—Natural Gas</td><td>NEMXDGTNG</td><td>N/A</td><td>NOx</td><td>EMx and Dry Low NOx Combustion</td><td>Gas Turbines—Natural Gas</td><td>ptnonipm</td><td>Emerging</td><td>15</td><td></td><td>2013</td><td>CT-1|CT-2|CT-3|CT-4|CT-5</td><td></td></tr>
<tr><td>EMx and Water Injection; Gas Turbines—Natural Gas</td><td>NEMXWGTNG</td><td>N/A</td><td>NOx</td><td>EMx and Water Injection</td><td>Gas Turbines—Natural Gas</td><td>ptnonipm</td><td>Emerging</td><td>15</td><td></td><td>2013</td><td>CT-1|CT-3</td><td></td></tr>
</table>

*For ease in reading this table, the Description field is included on separate pages.

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NDLNCGTNG	Application: This control is the use of dry low NOx combustion (DLN) technology to reduce NOx emissions. DLN combustion reduces the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to large (83.3 MW to 161 MW) natural gas fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to "stage" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
NSCRDGTNG	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to natural gas fired turbines with NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRSGTNG	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to natural gas fired turbines with NOx emissions greater than 10 tons per year.

(continued)

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NSCRSGTNG (cont.)	Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRWGTJF	Application: This control is the selective catalytic reduction of NOx through add-on controls in combination with water injection. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to jet fuel-fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water.

(continued)

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NSCRWGTJF (cont.)	Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRWGTNG	Application: This control is the selective catalytic reduction of NOx through add-on controls in combination with water injection. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to natural gas-fired gas turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRWGTOL	Application: This control is the selective catalytic reduction of NOx through add-on controls in combination with water injection. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to oil-fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002).

(continued)

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NSCRWGTOL (cont.)	Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or supports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSTINGTNG	Application: This control is the use of steam injection to reduce NOx emissions. This control applies to small (3.3 MW to 34.4MW) natural gas-fired gas turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Steam is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The steam can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).
NWTINGTJF	Application: This control is the use of water injection to reduce NOx emissions. This control applies to small (3.3 MW to 34.4MW) jet fuel-fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).
NWTINGTNG	Application: This control is the use of water injection to reduce NOx emissions. This control applies to small (3.3 MW to 34.4MW) natural gas-fired gas turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).
NWTINGTOL	Application: This control is the use of water injection to reduce NOx emissions. This control applies to small (3.3 MW to 34.4MW) oil-fired turbines with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber (ERG, 2000).

(continued)

Table B-1. CMDB Table 01_Summary (continued)

cmabbreviation	Description
NCATCGTNG	Application: This control is the use of catalytic combustion to reduce NOx emissions. Catalytic combustors reduce the amount of NOx created by oxidizing fuel at lower temperatures (and without a flame) than in conventional combustors. Catalytic combustion uses a catalytic bed to oxidize a lean air fuel mixture within a combustor instead of burning with a flame. The fuel and air mixture oxidizes at lower temperatures than in a conventional combustor, producing less NOx. Currently installed only on a few 1.4 MW combustion turbines, and commercially available for turbines rated up to 10 MW (CT-1).
NEMXDGTNG	Application: This control is the use of EMx in combination with dry low NOx combustion. EMx is a post-combustion catalytic oxidation and absorption technology that uses a two-stage catalyst/absorber system for the control of NOx as well as CO, VOC, and optionally SOx. A coated catalyst oxidizes NO to NO2, CO to CO2, and VOC to CO2 and water. The NO2 is then absorbed onto the catalyst surface where it is chemically converted to and stored as potassium nitrates and nitrites. A proprietary regeneration gas is periodically passed through the catalyst to desorb the NO2 from the catalyst and reduce it to elemental nitrogen (N2). EMx has been successfully demonstrated on several small combustion turbine projects up to 45 MW. The manufacturer has claimed that EMx can be effectively scaled up to larger turbines (CT-1). Cost estimates for DLN combustion in 2008 dollars are not available. Thus, the total system cost in this analysis in 2008 dollars was developed from 1999 cost estimates for DLN combustion that were escalated to 2008 dollars and added to the available 2008 estimate for the EMx system.
NEMXWGTNG	Application: This control is the use of EMx in combination with water injection. Cost estimates for water injection in 2008 dollars are not available. Thus, the total system cost in this analysis in 2008 dollars was developed from 1999 cost estimates for water injection that were escalated to 2008 dollars and added to the available 2008 estimate for the EMx system.

Table B-2. CMDB Table 02_Efficiencies

cmabbreviation	pollutant	locale	Effective Date	existingmeasureabbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equationtype	caprecfactor	discountrate	capannratio	incrementalcpt	details
NWTINGTNG	NOx				0	0	365	72	1999	1790	100	100	cpton	0.1098		3.1		Applied to small source types (<34.4 MW), uncontrolled emissions <365 tpy
NWTINGTNG	NOx				0	365		72	1999	1000	100	100	cpton	0.1098		2.4		Applied to small source types (<34.4 MW), uncontrolled emissions >365 tpy
NWTINGTNG	NOx				0	365		72	1999	730	100	100	cpton	0.1098		1.6		Applied to large source types
NSCRWGTNG	NOx				0	0	365	94	1999	2790	100	100	cpton	0.1098		3	5840	Applied to small source types (3 to 26 MW), uncontrolled emissions <365 tpy.
NSCRWGTNG	NOx				0	365		94	1999	1370	100	100	cpton	0.1098		2.9	3130	Applied to small source types (3 to 26 MW), uncontrolled emissions >365 tpy.
NSCRWGTNG	NOx				0	365		94	1999	1070	100	100	cpton	0.1098		1.5	1690	Applied to large source types (~80 to 160 MW)
NSCRWGTNG	NOx				0	365		98	2008	1960	100	100	cpton	0.1098		2.5	3170	Applied to large source types (~50 to 180 MW), 1999 costs for WI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units. 1999 WI capital and indirect annual costs were escalated to 2008 dollars using ratio of 2008 to 1999 CEP cost indexes, direct annual costs for WI were assumed to be the same in 2008 as in 1999, and resulting 2008 costs were added to the 2008 SCR costs from ref CT-3.
NEMXWGTNG	NOx				0	365		99	2008	2960	100	100	cpton	0.1098		2.9	7120	Applied to large source types (50 to 180 MW); WI costs estimated using the same procedure as for NSCRWGTNG applied to large sources.
NSTINGTNG	NOx				0	0	365	80	1999	1690	100	100	cpton	0.1098		3.5		Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy, 1999 costs for SI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed WI costs were essentially the same for NG-fired units (assumed same pattern holds for steam injection).
NSTINGTNG	NOx				0	365		80	1999	820	100	100	cpton	0.1098		3.5		Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy, 1999 costs for SI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed WI costs were essentially the same for NG-fired units (assumed same pattern holds for steam injection).
NSTINGTNG	NOx				0	365		80	1999	500	100	100	cpton	0.1098		3.0		Applied to large source types (~80 to 160 MW), 1999 costs for SI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed WI costs were essentially the same for NG-fired units (assumed same pattern holds for steam injection).
NSCRSGTNG	NOx				0	0	365	95	1999	2570	100	100	cpton	0.1098		3.3	5550	Applied to small source types (3 to 26 MW), uncontrolled emissions <365 tpy.

(continued)

Table B-2. CMDB Table 02_Efficiencies (continued)

cmabbreviation	pollutant	locale	Effective Date	existingmeasureabbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equationtype	caprecfactor	discountrate	capannratio	incrementalcpt	details
NSCRSGTNG	NOx				0	365		95	1999	1380	100	100	cpton	0.1098		3.1	2870	Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy.
NSCRSGTNG	NOx				0	365		95	1999	570	100	100	cpton	0.1098		2.7	1810	Applied to large source types (~80 to 160 MW)
NSCRGYNG	NOx				0	365		95	2008	1420	100	100	cpton	0.1098		3.9	3170	Applied to large source types (50 to 180 MW)
NDLNCGTNG	NOx				0	0	365	84	1999	300	100	100	cpton	0.1098		5	~~540~~	Applied to small source types
NDLNCGTNG	NOx				0	365		84	1999	130	100	100	cpton	0.1098		7.4	~~140~~	Applied to large source types
NSCRDGTNG	NOx				0	0	365	94	1999	1800	100	100	cpton	0.1098		2.9	11900	Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy.
NSCRDGTNG	NOx				0	365		94	1999	990	100	100	cpton	0.1098		3.6	6320	Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy.
NSCRDGTNG	NOx				0	365		94	1999	390	100	100	cpton	0.1098		4.2	3340	Applied to large source types (~160 MW)
NSCRDGTNG	NOx				0	365			2007								18900	Applied to small source types (up to 40 MW, uncontrolled emissions <365 tpy)
NSCRDGTNG	NOx				0		365		2007								7510	Applied to small source types (up to 40 MW, uncontrolled emissions >365 tpy)
NSCRDGTNG	NOx				0	365		94	2008	1040	100	100	cpton	0.1098		4.6	5560	Applied to large source types (~50 to 180 MW), 1999 costs for DLN were estimated based on data in ref CT-2. Escalated these costs to 2008 dollars using ratio of 2008 to 1999 CEP cost indexes and added to the 2008 SCR costs from ref CT-3.
NEMXDGTNG	NOx						365		1999	2860							14940	Applied to small source types (<26 MW), uncontrolled emissions <365 tpy
NEMXDGTNG	NOx					365			1999	1720							10270	Applied to small source types (<26 MW), uncontrolled emissions >365 tpy
NEMXDGTNG	NOx					365			1999	840							6600	Applied to large source types (170 MW), uncontrolled emissions >365 tpy
NEMXDGTNG	NOx				0		365											Applied to small source types
NEMXDGTNG	NOx				0	365		99	2008	2040	100	100	cpton	0.1098		4.1	12370	Applied to large source types (50 to 180 MW); DLN costs estimated in 1999 dollars were escalated to 2008 dollars using the CEPCI, except parts and repair costs were assumed to be the same in 2008 as in 1999.
NCATCGTNG	NOx				0		365	98	1999	920	100	100	cpton	0.1098		1.7	4760	Applied to small source types (3 to 26 MW), uncontrolled emissions <365 tpy.
NCATCGTNG	NOx				0		365	98	1999	670	100	100	cpton	0.1098		1.2	2580	Applied to small source types (3 to 26 MW), uncontrolled emissions >365 tpy.
NCATCGTNG	NOx				0	365		98	1999	370	100	100	cpton	0.1098		0.7	2200	Applied to large source types (~170 MW)
NWTINGTOL	NOx				0	0	365	68	1999	1630	100	100	cpton	0.1098		3.0		Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy, 1999 costs assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units.

Table B-2. CMDB Table 02_Efficiencies (continued)

cmabbreviation	pollutant	locale	Effective Date	existingmeasureabbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equationtype	caprecfactor	discountrate	capannratio	incrementalcpt	details
NWTINGTOL	NOx				0	365		68	1999	960	100	100	cpton	0.1098		1.8		Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy, 1999 costs assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units.
NWTINGTOL	NOx				0	365		68	1999	650	100	100	cpton	0.1098		1.6		Applied to large source types (~83 MW), uncontrolled emissions >365 tpy, 1999 costs assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units.
NSCRWGTOL	NOx				0	0	365	90	1990	3190	100	100	cpton	0.1098		2.9	7620	Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy.
NSCRWGTOL	NOx				0	365		90	1990	1320	100	100	cpton	0.1098		2.3	2450	Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy.
NSCRWGTOL	NOx				0	365		97	2004	1560	100	100	cpton	0.1098		2.3	4790	Applied to large source types (~83 MW), uncontrolled emissions >365 tpy, 1999 costs for WI assumed to be the same as 1990 costs in the 1993 ACT based on data in ref CT-2 that showed the costs were essentially the same for NG-fired units. Escalated these costs to 2004 dollars using ratio of 2004 to 1999 CEP cost indexes and added to the 2004 SCR costs from ref CT-7. Control efficiency based on data from analysis for one unit (ref CT-7).
NWTINGTJF	NOx				0	0	365	68	1999	1630	100	100	cpton	0.1098		3.0		Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy, costs assumed to be the same as for oil-fired turbines.
NWTINGTJF	NOx				0	365		68	1999	960	100	100	cpton	0.1098		1.8		Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy, costs assumed to be the same as for oil-fired turbines.
NWTINGTJF	NOx				0	365		68	1999	650	100	100	cpton	0.1098		1.6		Applied to large source types (~83 MW), uncontrolled emissions >365 tpy, costs and control efficiency assumed to be the same as for oil-fired turbines.
NSCRWGTJF	NOx				0	0	365	90	1990	3190	100	100	cpton	0.1098		2.9	7620	Applied to small source types (3 to 26.3 MW), uncontrolled emissions <365 tpy, costs assumed to be same as for oil-fired turbines.
NSCRWGTJF	NOx				0	365		90	1990	1320	100	100	cpton	0.1098		2.3	2450	Applied to small source types (3 to 26.3 MW), uncontrolled emissions >365 tpy, costs assumed to be same as for oil-fired turbines.
NSCRWGTJF	NOx				0	365		97	2004	1560	100	100	cpton	0.1098		2.3	4790	Applied to large source types (~83 MW), uncontrolled emissions >365 tpy, costs and control efficiency assumed to be same as for oil-fired turbines).

Table B-3. CMDB Table 04_Equations[a]

cmabbreviation	cmeqntype	pollutant	costyear	var1	var2	var3	var4	var5	var6	var7	var8	var9	var10
NWTINGTNG	Type 2	NOx	1999	27665	0.69	3700.2	0.95	27665	0.69	3700.2	0.95		
NSCRWGTNG	Type 2	NOx	1999	62962	0.66	8590	0.87	37193	0.63	12065	0.64		
NSCRWGTNG	Type 2	NOx	2007					210883	0.46				
NSCRWGTNG	Type “L”	NOx	2007							1893.8	185570		
NSCRWGTNG	Type 2	NOx	2008	34533	0.85	7236	0.94	10323	0.96	3106	0.94		
NEMXWGTNG	Type 2	NOx	2008	200894	0.68	19215	0.86	160409	0.67	20174	0.78		
NSTINGTNG	Type 2	NOx	1999	43092	0.66	7282.3	0.76	43092	0.66	7282.3	0.76		
NSCRSGTNG	Type 2	NOx	1999	72169	0.66	17551	0.72	37193	0.63	12065	0.64		
NSCRSGTNG	Type 2	NOx	2008	46492	0.82	9434.1	0.86	10323	0.96	3106	0.94		
NDLNCGTNG	Type 2	NOx	1999			676.37	0.96			676.37	0.96		
NDLNCGTNG	Type “L”	NOx	1999	2860.6	25427			2860.6	25427				
NSCRDGTNG	Type 2	NOx	1999	24854	0.79	12725	0.69	37193	0.63	12065	0.64		
NSCRDGTNG	Type 2	NOx	2007	187647	0.54			210883	0.46				
NSCRDGTNG	Type “L”	NOx	2007			2782	167494			1893.8	185570		
NSCRDGTNG	Type 2	NOx	2008	14785	0.97	5250.8	0.9	10323	0.96	3106.1	0.94		
NEMXDGTNG	Type 2	NOx	1999	58237	0.78	15004	0.78	65163	0.72	13702	0.76		
NEMXDGTNG	Type 2	NOx	2008	129611	0.74	23051	0.78	160409	0.67	20174	0.78		
NCATCGTNG	Type 2	NOx	1999	20668	0.57	4254.2	0.82						
NCATCGTNG	Type “L”	NOx	1999					N/A	N/A	743.2	54105		
NWTINGTOL	Type 2	NOx	1999	42533	0.6	6776.7	0.8	42533	0.6	6776.7	0.8		
NSCRWGTOL	Type 2	NOx	1990	94337	0.63	25914	0.7						
NSCRWGTOL	Type “L”	NOx	1999					4868.5	349694	1546.1	139203		

[a]Type “L” is a linear equation; variables are the slope and intercept. No incremental TCI for NCATCGTNG relative to DLN because the capital costs for catalytic combustion are lower than the capital costs for DLN for all but the smallest turbines. The underlying data for 2008 costs for SCR and EMx are for large turbines (50 MW to 180 MW). The underlying data for 2007 costs are for 1 MW to 40 MW turbines.

Table B-4. Additional CMDB Table 06 References

Data Source	Description
CT-1	Bay Area Air Quality Management District, 2010. Preliminary Determination of Compliance. Marsh Landing Generating Station. March 2010. Available at: http://www.energy.ca.gov/sitingcases/marshlanding/documents/other/2010-03-24_Bay_Area_AQMD_PDOC.pdf
CT-2	Onsite Sycom Energy Corporation, 1999. "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines." Prepared for U.S. Department of Energy. Environmental Programs Chicago Operations Office. November 5, 1999. Available at: https://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/gas_turbines_nox_cost_analysis.pdf
CT-3	EmeraChem Power, 2008. Attachment in email from Jeff Valmus, EmeraChem Power, to Weyman Lee, BAAQMD. Request for EMx Cost Information. September 8, 2008. Available at: http://www.baaqmd.gov/~/media/Files/Engineering/Public%20Notices/2010/18404/Footnotes/EMx%20BACT%20economic%20analysis%20final09072008.ashx
CT-4	CH2MHill, 2002. Walnut Energy Center Application for Certification." Prepared for California Energy Commission. November 2002. Available at: www.energy.ca.gov/sitingcases/turlock/documents/applicant_files/volume_2/App_08.01E_Eval_Control.pdf.
CT-5	CARB, 2004. California Environmental Protection Agency. Air Resources Board. Report to the Legislature. Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts. Stationary Source Division. May 2004. Available at: http://www.arb.ca.gov/research/apr/reports/l2069.pdf
CT-6	Resource Dynamics Corporation, 2001. "Assessment of Distributed Generation Technology Applications." Prepared for Maine Public Utilities Commission. February 2001. Available at: http://www.distributed-generation.com/Library/Maine.pdf
CT-7	Florida Municipal Power Agency, 2004. Chapters 3 and 4 of PSD BACT analysis for Stock Island facility in Key West, Florida. Available at http://www.dep.state.fl.us/air/emission/construction/stockisland/BasisofBACT.pdf and http://www.dep.state.fl.us/air/emission/construction/stockisland/NOxBACT.pdf
CT-8	Energy and Environmental Analysis (An ICF International Company), 2008. Technology Characterization: Gas Turbines. Prepared for Environmental Protection Agency Climate Protection Partnership Division. December 2008. Available at: http://www.epa.gov/chp/documents/catalog_chptech_gas_turbines.pdf

APPENDIX C
GLASS MANUFACTURING

Copies of database tables showing all records for glass manufacturing controls, highlighting revisions.

Table C-1. CMDB Table 01 Summary

cmname	cmabbreviation	pechanmeascode	major poll	controltechnology	sourcegroup	Sector	Class	equiplife	neidevicecode	datereviewed	datasource	Months	Description
Cullet Preheat; Glass Manufacturing—Container	NCLPTGMCN	N0302	NOx	Cullet Preheat	Glass Manufacturing—Container	ptnonipm	Emerging	10		2013	72|175|182|GM-1		
Cullet Preheat; Glass Manufacturing—Pressed	NCUPHGMPD	N0322	NOx	Cullet Preheat	Glass Manufacturing—Pressed	ptnonipm	Emerging	10		2013	72|175|182|GM-1		
OXY-Firing; Glass Manufacturing—General	NDOXYFGMG	N/A	NOx	OXY-Firing	Glass Manufacturing—General	ptnonipm	Emerging	10			167		
Electric Boost; Glass Manufacturing—General	NELBOGMGN	N0301	NOx	Electric Boost	Glass Manufacturing—Container	ptnonipm	Known	10		2013	GM-1		
Electric Boost; Glass Manufacturing—Container	NELBOGMCN	N0301	NOx	Electric Boost	Glass Manufacturing—Container	ptnonipm	Known	10		2006	72|175|182		
Electric Boost; Glass Manufacturing—Flat	NELBOGMFT	N0311	NOx	Electric Boost	Glass Manufacturing—Flat	ptnonipm	Known	10		2006	72|175|182		
Electric Boost; Glass Manufacturing—Pressed	NELBOGMPD	N0321	NOx	Electric Boost	Glass Manufacturing—Pressed	ptnonipm	Known	10		2006	72|175|182		
Low NOx Burner; Glass Manufacturing—Container	NLNBUGMCN	N0303	NOx	Low NOx Burner	Glass Manufacturing—Container	ptnonipm	Known	10	204|205	2013	72|175|179|182|GM-2		
Low NOx Burner; Glass Manufacturing—Flat	NLNBUGMFT	N0312	NOx	Low NOx Burner	Glass Manufacturing—Flat	ptnonipm	Known	10	204|205	2013	72|175|179|182|GM-2		
Low NOx Burner; Glass Manufacturing—Pressed	NLNBUGMPD	N0323	NOx	Low NOx Burner	Glass Manufacturing—Pressed	ptnonipm	Known	10	204|205	2006	175|179|182		
OXY-Firing; Glass Manufacturing—General	NOXYFGMGN	N0306	NOx	OXY-Firing	Glass Manufacturing—Container	ptnonipm	Known	10		2013	GM-1		
OXY-Firing; Glass Manufacturing—Container	NOXYFGMCN	N0306	NOx	OXY-Firing	Glass Manufacturing—Container	ptnonipm	Known	10		2006	72		
OXY-Firing; Glass Manufacturing—Flat	NOXYFGMFT	N0315	NOx	OXY-Firing	Glass Manufacturing—Flat	ptnonipm	Known	10		2006	72		
OXY-Firing; Glass Manufacturing—Pressed	NOXYFGMPD	N0326	NOx	OXY-Firing	Glass Manufacturing—Pressed	ptnonipm	Known	10		2006	72		
Selective Catalytic Reduction; Glass Manufacturing—Container	NSCRGMCN	N03403	NOx	Selective Catalytic Reduction	Glass Manufacturing—Container	ptnonipm	Known	10	139	2013	72|172|175|179|182|224|GM-2		
Selective Catalytic Reduction; Glass Manufacturing—Flat	NSCRGMFT	N0314	NOx	Selective Catalytic Reduction	Glass Manufacturing—Flat	ptnonipm	Known	10	139	2013	72|172|175|179|182|186|224|GM-2		
Selective Catalytic Reduction; Glass Manufacturing—Pressed	NSCRGMPD	N0325	NOx	Selective Catalytic Reduction	Glass Manufacturing—Pressed	ptnonipm	Known	10	139	2006	72|172|175|179|182|186|224		
Catalytic Ceramic Filter; Glass Manufacturing—Flat	CATCFGMFT		NOx	Catalytic Ceramic Filter	Glass Manufacturing—Flat	ptnonipm	Known	20		2013	GM-3		

Table C-1. CMDB Table 01 Summary—Description Field

cmabbreviation	description
NCLPTGMCN	Application: This control is the use of cullet preheat technologies to reduce NOx emissions from glass manufacturing operations. This control is applicable to container glass manufacturing operations classified under 305010402.
NCUPHGMPD	Application: This control is the use of cullet preheat technologies to reduce NOx emissions from glass manufacturing operations. This control is applicable to pressed glass manufacturing operations classified under 305010404.
NDOXYFGMG	Application: This control is the use of OXY-firing in glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called “oxy-firing.” Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.
NELBOGMGN	Application: This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to general glass manufacturing operations classified under SCC 30501401.
NELBOGMCN	Application: This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to container glass manufacturing operations classified under SCC 30501402. Discussion: The 250 tons per day plant is assumed to be representative of container glass plants (Pechan, 1998).
NELBOGMFT	Application: This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to flat glass manufacturing operations classified under SCC 30501403. Discussion: The 500 tons per day plant is assumed to be representative of flat glass plants (Pechan, 1998).
NELBOGMPD	Application: This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to pressed glass manufacturing operations classified under SCC 30501403. Discussion: The 50 tons per day plant is assumed to be representative of pressed glass plants (Pechan, 1998).
NLNBUGMCN	Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to container glass manufacturing operations classified under 305010402 with uncontrolled NOx emissions greater than 10 tons per year. Discussion: The 250 tons per day plant is assumed to be representative of container glass plants (Pechan, 1998). LNBs are designed to “stage” combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
NLNBUGMFT	Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to flat glass manufacturing operations classified under 305010404 with uncontrolled NOx emissions greater than 10 tons per year. Discussion: The 500 tons per day plant is assumed to be representative of flat glass plants (Pechan, 1998). LNBs are designed to “stage” combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).

(continued)

Table C-1. CMDB Table 01 Summary—Description Field (continued)

cmabbreviation	description
NLNBUGMPD	Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amo
NOXYFGMGN	Application: This control is the use of OXY-firing in flat glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called "oxy-firing." This control applies to general manufacturing operations. This control applies to general glass manufacturing operations classified under SCC 30501401. Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.
NOXYFGMCN	Application: This control is the use of OXY-firing in container glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called "oxy-firing." Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.
NOXYFGMFT	Application: This control is the use of OXY-firing in flat glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called "oxy-firing." This control applies to flat-glass manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year. Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.
NOXYFGMPD	Application: This control is the use of OXY-firing in pressed glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called "oxy-firing." Discussion: The basic rationale for oxy-firing is improved efficiency, i.e., more of the theoretical heat of combustion is transferred to the glass melt and is not lost in the flue gas. Many other combustion modification techniques (e.g., flue gas recirculation, staged combustion, and low excess air combustion) reduce NOx formation but also reduce the combustion efficiency. Oxy-firing was originally developed to improve the combustion efficiency primarily by eliminating the sensible heat lost in heating the nitrogen present in air, which is then lost in the flue gas.

(continued)

Table C-1. CMDB Table 01 Summary—Description Field (continued)

cmabbreviation	description
NSCRGMCN	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. Applies to glass-container manufacturing processes, classified under SCC 30501402 and uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
NSCRGMFT	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. Applies to large(>1 ton NOx per OSD) flat-glass manufacturing operations (SCC 30501403) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).

(continued)

Table C-1. CMDB Table 01 Summary—Description Field (continued)

cmabbreviation	description
NSCRGMPD	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. Applies to pressed-glass manufacturing operations, classified under SCC 30101404 and uncontrolled NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
CATCFGMFT	Application: Filter tubes have nanobits of proprietary catalyst are embedded throughout the filter walls. The system can achieve excellent NOx removal using liquid ammonia that is injected upstream of the filters, reacting with NOx at the catalyst to form nitrogen gas and water vapor. This control applies to general glass manufacturing operations classified under SCC 30501403

Table C-2. CMDB Table 02 Efficiencies

cmabbreviation	pollutant	locale	Effective Date	existing measure abbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equation type	caprecfactor	discountrate	capannratio	incrementalcpt	details
NCLPTGMCN	NOx				0	365	0	5	2002	5000	100	100	cpton	0.1424		4.5		Applied to large source types
NCLPTGMCN	NOx				0	0	365	5	2002	5000	100	100	cpton	0.1424		4.5		Applied to small source types
NCUPHGMPD	NOx				0	365		5	2002	5000	100	100	cpton	0.1424		4.5		Applied to large source types
NCUPHGMPD	NOx				0	0	365	5	2002	5000	100	100	cpton	0.1424		4.5		Applied to small source types
NELBOGMCN	NOx				0	365		10	1990	7150	100	100	cpton	0.1424		0		Applied to large source types
NELBOGMCN	NOx				0	0	365	10	1990	7150	100	100	cpton	0.1424		0		Applied to small source types
NELBOGMFT	NOx				0	365		10	1990	2320	100	100	cpton	0.1424		0		Applied to large source types
NELBOGMFT	NOx				0	0	365	10	1990	2320	100	100	cpton	0.1424		0		Applied to small source types
NELBOGMPD	NOx				0	365		10	1990	8760	100	100	cpton	0.1424		0		Applied to large source types
NELBOGMPD	NOx				0	0	365	10	1990	2320	100	100	cpton	0.1424		0	8760	Applied to small source types
NELBOGMGN					0	365	0	30	2002	7100	100	100	cpton	0.1424		0		Applied to large source types
NELBOGMGN					0	0	365	30	2002	7100	100	100	cpton	0.1424		0		Applied to small source types
NLNBUGMCN	NOx				0	365		40	2007	1072	100	100	cpton	0.14		4.3	1690	Applied to large source types
NLNBUGMCN	NOx				0	0	365	40	2007	1365	100	100	cpton	0.14		4.2	1690	Applied to small source types
NLNBUGMFT	NOx				0	0	365	40	2007	574	100	100	cpton	0.14		4.2		Applied to small source types
NLNBUGMFT	NOx				0	365		40	2007	447	100	100	cpton	0.14		4.3		Applied to large source types
NLNBUGMPD	NOx				0	365		40	1990	1500	100	100	cpton	0.1424		2.2		Applied to large source types
NLNBUGMPD	NOx				0	0	365	40	1990	1500	100	100	cpton	0.1424		2.2		Applied to small source types
NOxYFGMCN	NOx				0	0	365	85	1990	4590	100	100	cpton	0.1424		2.7		Applied to small source types
NOxYFGMCN	NOx				0	365		85	1990	4590	100	100	cpton	0.1424		2.7		Applied to large source types
NOxYFGMFT	NOx				0	365		85	1990	1900	100	100	cpton	0.1424		2.7		Applied to large source types
NOxYFGMFT	NOx				0	0	365	85	1990	1900	100	100	cpton	0.1424		2.7		Applied to small source types
NDOXYFGMG	NOx				0			85	1999	4277	100	100	cpton					
NOxYFGMPD	NOx				0	0	365	85	1990	3900	100	100	cpton	0.1424		2.7		Applied to small source types
NOxYFGMPD	NOx				0	365		85	1990	3900	100	100	cpton	0.1424		2.7		Applied to large source types
NOxYFGMGN						365	0	85	2002	2353	100	100	cpton	0.1424		2.7		Applied to large source types
NOxYFGMGN						0	365	85	2002	2353	100	100	cpton	0.1424		2.7		Applied to small source types
NSCRGMCN	NOx				0	365	0	75	2007	1684	100	100	cpton	0.1424		4.2		Applied to large source types
NSCRGMCN	NOx				0	0	365	75	2007	2169	100	100	cpton	0.1424		4.5		Applied to small source types
NSCRGMFT	NOx				0	365	0	75	2007	855	100	100	cpton	0.1424		3.7	710	Applied to large source types
NSCRGMFT	NOx				0	0	365	75	2007	957	100	100	cpton	0.1424		3.4		Applied to small source types

(continued)

Table C-2. CMDB Table 02 Efficiencies (continued)

cmabbreviation	pollutant	locale	Effective Date	existing measure abbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equation type	caprecfactor	discountrate	capannratio	incrementalcpt	details
NSCRGMPD	NOx				0	365		75	1990	2530	100	100	cpton	0.1424		1.3		Applied to large source types
NSCRGMPD	NOx				0	0	365	75	1990	2530	100	100	cpton	0.1424		1.3		Applied to small source types
CATCFGMFT	NOx				0	365	0	95	2013	997	100	100	cpton	0.05		4.6		Applied to large source types
CATCFGMFT	NOx				0	0	365	95	2013	1045	100	100	cpton	0.05		4.6		Applied to small source types

Table C-3. CMDB Table 06 References (New)

Data Source	Description
GM-1	Oxygen Enriched Air Staging a Cost-effective Method For Reducing NOx Emissions. Industrial Technologies. April 2002. Available at: http://www1.eere.energy.gov/manufacturing/resources/glass/pdfs/airstaging.pdf
GM-2	Best Available Techniques (BAT) Reference Document for the Manufacture of Glass. European Commission 2013. Available at: http://eippcb.jrc.ec.europa.eu/reference/BREF/GLS_Adopted_03_2012.pdf
GM-3	Confidential Vendor Quote

Table C-4. CMDB Table 04_Equations[a]

cmabbreviation	cmeqntype	pollutant	costyear	var1	var2	var3	var4	var5	var6	var7	var8	var9	var10
NLNBUGMCN	Type 2	NOx	2008	30,930	0.45	9,377	0.40						
NLNBUGMFT	Type “L”	NOx	2008	527	664,557	132	150,105						
NSCRGMCN	Type 2	NOx	2008	79,415	0.51								
NSCRGMCN	Type “L”	NOx	2008			643	135,302						
NSCRGMFT	Type “L”	NOx	2008	3,681	1,000,000	842	424,930						

[a]Type “L” is a linear equation; variables are the slope and intercept.

APPENDIX D
LEAN BURN ENGINES

Copies of the database tables for showing all records for Lean Burn Engine NOx controls are provided:

– Table D-01_Summary

– Table D-02_Efficiencies

– Table D-03_SCCs

– Table D-04_Equations

– Table D-06_References

Table D-01_Summary

cmname	cmabbreviation	pechanmeascode	majorpoll	controltechnology	sourcegroup	sector	class	equiplife	neidevicecode	datereviewed	datasource	months	description
Low Emission Combustion; Lean Burn ICE—NG	NLECICENG		NOx	Low Emission Combustion	Lean Burn ICE—NG	PTNONIPM	Known	10		9/15/2013	ABCD3		Low Emission Combustion includes Precombustion chamber head and related equipment on a Lean Burn engine.
Layered Combustion; Lean Burn ICE 2 stroke—NG	NLCICE2SNG		NOx	Layered Combustion	Lean Burn ICE—NG	PTNONIPM	Known	10		9/15/2013	ABCD1		Layered combustion—2 stroke, Lean Burn, NG (Air Supply; Fuel Supply; Ignition; Electronic Controls; Engine Monitoring). Evaluation for 3 most representative made/models of 2 stroke LB compressor engines. All retrofit combustion-related controls may not be available for all manufacturers and models of 2-stroke lean burn engines. Actual NOx emission rates would be engine design specific. Efficiency achieved may range from 60 to 90%, depending on the make/model of engine (approximate range of NOx emissions of 3.0 to 0.5 g/bhp-hr).
Layered Combustion; Lean Burn ICE 2 stroke Large Bore—NG	NLCICE2SLBNG		NOx	Layered Combustion	Lean Burn ICE—NG	PTNONIPM	Known	10		9/15/2013	ABCD1		Layered combustion—for Large Bore, 2 stroke, Lean Burn, Slow Speed (High Pressure Fuel Injection achieves 90% reduction; Turbocharging achieves 75% reduction; Precombustion chambers achieves 90% reduction; Cylinder Head Modifications). All retrofit combustion-related controls may not be available for all manufacturers and models of 2-stroke lean burn engines. Actual NOx emission rates would be engine design specific. Efficiency achieved may range from 60 to 90%, depending on the make/model of engine (approximate range of NOx emissions of 3.0 to 0.5 g/bhp-hr).
Air to Fuel Ratio Controller; Lean Burn ICE—NG	NAFRCICENG		NOx	Air to Fuel Ratio Controller	Lean Burn ICE—NG	PTNONIPM	Known	10		12/5/2012	ABCD3		
Selective Catalytic Reduction; Lean Burn ICE 4 Stroke—NG	NSCRICE4SNG		NOx	Selective Catalytic Reduction	Lean Burn ICE—NG	PTNONIPM	Known	10		9/15/2013	ABCD1| ABCD2| ABCD3		SCR can be used on Lean Burn, NG engines. Assumed SCR can meet NOx emissions of 0.89 g/bh-hr. This is a Known technology, however there is indication that applicability is engine/unit specific.
Selective Catalytic Reduction; ICE—Diesel	NSCRICEDS		NOx	Selective Catalytic Reduction	ICE—Diesel	PTNONIPM	Known	7		9/15/2013	ABCD4		SCR can be used on Diesel engines.

Table D-02_Efficiencies

cmabbreviation	pollutant	locale	Effective Date	existingmeasureabbr	neiexistingdevcode	minemissions	maxemissions	controlefficiency	costyear	costperton	ruleeff	rulepen	equationtype	caprecfactor	discountrate	capannratio	incrementalcpt	details
NLECICENG	NOx	NA	NA	NA	NA	0	365	80	2001	1,000	100	100	cpton	0.1424	7	7.025	NA	
NLCICE2SNG	NOx	NA	NA	NA	NA	0	365	97	2009	4,900	100	100	cpton	0.1424	7	7.024	NA	
NLCICE2SLBNG	NOx	NA	NA	NA	NA	365	0	97	2010	1,500	100	100	cpton	0.1424	7	7.024	NA	Apply to large source types. Assumed Interest Rate of 7 percent (not provided in documentation) to calculate annual costs.
NLCICE2SLBNG	NOx	NA	NA	NA	NA	0	365	97	2010	38,000	100	100	cpton	0.1424	7	7.024	NA	Apply to small source types.
NAFRCICENG	NOx	NA	NA	NA	NA	0	365	80	2001	200	100	100	cpton	0.1424	7	7.023	NA	
NSCRICE4SNG	NOx	NA	NA	NA	NA	0	365	96	2001	2,900	100	100	cpton	0.1424	7	1.401	NA	
NSCRICEDS	NOx	NA	NA	NA	NA	0	365	90	2005	9,300	100	100	cpton	0.1098	7	2.45	NA	

Table D-03_SCCs

cmabbreviation	Source Classification Code	Status
NLECICENG	20200252	
NLECICENG	20200254	
NLECICENG	20200255	
NLECICENG	20200256	
NLCICE2SNG	20200252	
NLCICE2SNG	20200254	
NLCICE2SNG	20200255	
NLCICE2SNG	20200256	
NLCICE2SLBNG	20200252	
NLCICE2SLBNG	20200254	
NLCICE2SLBNG	20200255	
NLCICE2SLBNG	20200256	
NLCICE2SLBNG	20200401	
NLCICE2SLBNG	20200402	
NLCICE2SLBNG	20200403	
NAFRCICENG	20200252	
NAFRCICENG	20200254	
NAFRCICENG	20200255	
NAFRCICENG	20200256	
NSCRICE4SNG	20200252	
NSCRICE4SNG	20200254	
NSCRICE4SNG	20200255	
NSCRICE4SNG	20200256	
NSCRICEDS	20200102	
NSCRICEDS	20200107	

Table D-04_Equations

cmabbreviation	cmeqntype	pollutant	costyear	var1	var2	var3	var4	var5	var6	var7	var8	var9	var10
NSCRICE4SNG	linear capital and annual	NOx	2001	107.1	27186	83.64	14718						
NLECICENG	capital and annual	NOx	2001	16019	0.0016	2280.8	0.0016						
NAFRCICENG	linear capital and annual	NOx	2001	1.0337	4354.5	0.1852	619.99						

Table D-06 References

Data Source	Description
ABCD1	OTC 2012. Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final. October 17, 2012.
ABCD2	SJVAPCD 2003. RULE 4702—Internal Combustion Engines—Phase 2. Appendix B, Cost Effectiveness Analysis for Rule 4702 (Internal Combustion Engines—Phase 2). San Joaquin Valley Air Pollution Control District. July 17, 2003. www.arb.ca.gov/pm/pmmeasures/ceffect/rules/sjvapcd_4702.pdf
ABCD3	CARB 2001. Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines. California Environmental Protection Agency, Air Resources Board, Stationary Source Division, Emissions Assessment Branch, Process Evaluation Section. November 2001.
ABCD4	EPA 2010. Alternative Control Techniques Document: Stationary Diesel Engines. March 5, 2010.

APPENDIX E
NOTES PROVIDED HERE TO EPA QUESTIONS ON LEAN BURN RICE

EPA Question 1: What is the applicability of SCR to RICE, especially Lean Burn?

Notes for Question 1

In addition to the two documents cited in Section 5 of the report with costs for selective catalytic reduction (SCR) for Lean Burn (LB) engines, there are several other references that indicate SCR is feasible for LB engines and several that provide input on technical issues related to SCR use for LB engines. In summary, from the references reviewed, SCR seems to be technically feasible in most instances for LB engines, however, SCR application may not be feasible in all cases due to technical issues at individual sites and individual engines. In addition, SCR costs are higher relative to other NOx control techniques for LB engines. See more detailed discussion below.

SCR can be applied to LB engines, achieving greater than 90 percent NOx reductions (Table 4 on p. 6 provides a slightly different value, greater than 95 percent). The costs [assumed this referred to capital costs] ranged from $50/hp to $125/hp. No annual operating costs were provided. In discussions on p. 8 regarding “catalysts on IC engines” in general (including NSCR, SCR, oxidation, and Lean-NOx), it is noted that “Thousands of stationary IC engine catalyst applications have been effectively used for stationary IC engine gaseous emission control for five years or more. Some installations, however, do experience performance loss over time,” however the text goes on to explain remedies for catalyst poisoning issues. Costs [capital] for SCR, LB ranged from $50 to $125/hp (no cost year provided). (MECA 1997)

The literature suggests that SCR is technically feasible for LB engines but there are problems that make SCR installation questionable. Two stroke (2S) LB engines are sensitive to changes in exhaust pressure, which could be problematic for retrofit of SCR on existing engines, but can be alleviated with proper design and sizing of airflow and exhaust components. This reference cited a presentation that indicated the following issues with SCR: applying SCR to pipeline engines is not feasible because the exhaust temperatures (T) are below the operating window for SCR or where SCR effectiveness is reduced; SCR installations are at unmanned facilities; and SCR has not been demonstrated for variable loads. However, the OTC 2012 reference responded to each of these issues, stating that there are several manufacturers and suppliers that offer SCR systems that indicate their catalysts are capable of effectively operating over a wide range of exhaust gas T; modern software based controls and SCADA communication technologies allow operation from a remote location; and SCR can function properly over a broad range of loads given catalysts that are effective over wide T ranges, modern controls regulate fuel and air flows to ensure combustion O_2 and T are at expected levels and to regulate reagent flow. A study conducted for retrofitting existing pipeline engines indicates that SCR is a high cost alternative to combustion improvements, primarily due to the high cost of ongoing reagent consumption. (p. 25-26) (There is a similar discussion for SCR for four stroke (4S) LB on p. 39-40; cited presentation at Gas Machinery Conference in October 2011.) (OTC 2012)

Shell indicated they have installed SCR on diesel engines (LB) that they utilize in drilling rig operations. Shell indicated that have been able to achieve greater than 90 percent reduction in NOx emissions while encountering minimal operational issues (see p. 10). (OTC 2012)

The OTC 2012 document indicated that MECA has noted there have been limited examples to date of SCR retrofit on 2S LB engines as demonstration test programs, but the results of these programs have not been published (see p. 27). It appears that SCR for NOx does not appear to be technically infeasible generically but that individual 2S LB engine characteristics and installations may be greatly problematic or not cost effective, although this site-specific issue is not altogether different than other emission reduction technologies (see p.27, 40). (OTC 2012)

The OTC 2012 document indicated that MECA has stated the commercial use of SCR systems for LB stationary engines have been in place since the mid-1980's in Europe and since the early 1990s in the US. One MECA member company has installed over 400 SCR systems worldwide for stationary engines with varying fuel combinations, including dozens of NG compressor engines in the US. These 4S LB engines with urea-SCR achieve >90% NOx reduction (see p.40). (OTC 2012)

EF&EE announced in November 2010 that is received an order from Clean Air Power Inc. for 6 SCR systems, to be installed on large LB NG compressor engines at gas storage sites in TX and MS (see p.40). (OTC 2012)

Clean Air Power cited: 4 SCRs supplied at Pine Prairie Energy Center, Louisiana; 1 SCR supplied at EXTERRAN/TRESPALACIOS, Texas; and 4 SCRs supplied to EXTERRAN/LEAF River, Mississippi (see p.41). (OTC 2012)

A PowerPoint slide presentation from a MARAMA workshop discusses the use of SCR for RICE and LB. Johnson Mathey (JM) included SCR as a feasible control for LB engines in a presentation at a May 2011 MARAMA Workshop. (The SCR systems included Urea and Ethanol as reagents.) SCR operating temperatures range from 700 to 900°F for internal combustion (IC) engines and achieved 90 percent NOx reductions. The budgetary costs [assumed this referred to capital costs] ranged from $150/ hp for a 500 hp unit (approximately $75,000) to $42/hp for a 3000 hp unit (approximately $126,000) (cost year not provided). No annual operating costs were provided. JM cited 4 LB engine installations of SCR on gas compressors at 2 locations, including Loudon Compressor Station in Clarksburg, WV and Lodi Compressor/Storage in Kirby Hills, CA. (Chu 2011) These engines are listed in the following table:

SCR for Lean Burn Engines—Johnson Mathey presentation at 2007 MARAMA Workshop

Engine Model	Engine hp	NOx, g/bhp-hr	NOx Reduction, %
CAT G3516	1,340	1.5	90%
CAT G3608	2,370	0.7	90%
CAT G3612	3,550	0.7	90%
CAT G3616	4,735	0.7	90%

References

(MECA 1997). *Emission Control Technology for Stationary Internal Combustion Engines: Status Report*. Manufacturers of Emission Controls Association (MECA). July 1997.

(Chu 2011). *NOx Control for Stationary Gas Engines*. W. Chu, Johnson Mathey. Presented at Advances in Air Pollution Control Technology, MARAMA Workshop. May 19, 2011.

(OTC 2012). *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final.* October 17, 2012.

EPA Question 2: What are credible estimates of the percentage of RICE NOx Emissions that are lean burn versus rich burn when RICE emissions are unspecified?

Notes for Question 2

There does not seem to be much information on NOx emission totals for LB and rich burn (RB) engines. A few references attempted to provide information on the numbers or populations of LB and RB engines. Several of the references highlighted surveys of engine populations and summary information from various engine databases. These data in general tend to point to a large LB engine population, however most of the references noted that RB engines are typically not captured or covered in surveys, databases, or by permits because the RB engines tend to be smaller in size. In general, larger engines tend to be LB and smaller engines tend to be RB. The ERLE 2009 study noted that approximately 73% of the 5,600 engines/horsepower capacity covered in their study of NG pipeline systems are LB, and approximately 6% are RB (the balance is not known). In the KSU 2011 database, approximately 66% of the 4,729 engines used in E&P at major sources are LB and 34% are RB. In addition, the EDF 2008 document cited a 2007 survey conducted for DFW NAA and AA that attempted to identify those engines that did not meet reporting requirement thresholds and were therefore not included in the TCEQ inventory. This reference, which included small engines, indicated that for smaller engines <500 hp, approximately 96% are RB and 4% are LB. The reference also indicated that for larger engines >500 hp, there is approximately a 50-50 split of LB and RB engines and of horsepower capacity. The ETCG 2013 reference also highlights engines in the Barnett Shale region. Data from the TCEQ Barnett Shale Special Inventory (Phase I) survey indicated that the majority of engines in the Barnett Shale are RB (84%). For those engines <240 hp, 95% are RB and 5% are LB, however, in looking at those engines >240 hp, 59% are LB and 41% are RB. More details for each of these references are provided in the discussion that follows.

Note also that the emissions rate in g/bhp-hr for LB engines tend to be higher, and the emissions rate for RB engines tends to be lower. (See the tables under Question 4 of this appendix for relative emission rate values for LB and RB engines in various states and local districts.)

A summary of the information available from various references is provided below.

The CARB 2001 reference indicated that LB engines tend to be larger in size, and smaller engines tend to be RB (p.B-4). (CARB 2001)

EPA received comments from the Interstate Natural Gas Association of America (INGAA) on the 2002 proposed rule, where EPA indicated that 156 of 168 large engines listed in the NOx SIP Call Inventory that have SIC codes associated with the NG transmission industry are LB engines (with the exception that the other 12 engines are no longer in service, are owned by a company not included in the industry database, or are duplicates). INGAA recommended that EPA assume all large NG stationary engines in the inventory are LB. (EPA 2003).

One prominent use of large Reciprocating Internal Combustion Engines (RICE) is to drive NG pipeline compressor stations; almost all engines affected by the NOx SIP Call Phase 2 rule in IL (except for 3 engines) are used to compress NG at NG pipeline stations. (IEPA 2007)

A 2009 ERLE study cited in this reference indicated there are 5,600 engines on the NG pipeline systems with a collective rating of 9,150,000 hp. That study further indicated that approximately 80 percent of the rated output was low speed 2S, low speed 4S integral engines and diesel medium speed engines converted to spark ignition (SI). Of these 80 percent of engines, 78 percent were 2S LB, 14 percent were 4S LB, and 8 percent were 4S RB. (On a rated horsepower basis, 80 percent was 2S LB, 15 percent was 4S LB, and 5 percent 4S RB) (p. 16). [On an overall basis, compared to the full 9,150,000 hp collective rating, 2S LB would be roughly 62%, 4S LB would be roughly 11%, and 4S RB would be roughly 6% of the overall rating/engines. So 73% would be LB, 6% would be RB, and the balance is not known.] (OTC 2012)

Engine Type	No. Engines, %	Horsepower, %
2S LB	78	80
4S LB	14	15
4S RB	8	5

The DE 2012 document cited a 2003 Pipeline Research Council International (PRCI) document that identified 5,686 engines: 71% are LB and 29% are RB (based on dropping the turbine numbers in the table below) (p.19). (DE 2012) [These data may be repeated in OTC 2012, as it looks fairly similar to the 2009 ERLE study data cited above from OTC 2012.]

2003 Pipeline Research Council International Data (PRCI)

Unit Type	U.S. Total Units (%)	Avg hp
2S LB	2,955 (44%)	2,113
4S LB	1,059 (16%)	1,844
RB	1,672 (25%)	589
Turbine	1,016 (15%)	6,121

Energy Information Agency (EIA) data cited in the OTC 2012 reference indicated there were 1201 NG mainline compressor stations in the U.S. in 2006, with combined rating of 16,800,000 hp. Between 2007 and 2010, the Federal Energy Regulation Commission (FERC) approved new compressor stations or upgrades to existing compressor facilities that were expected to add 2,600,000 hp (p. 16). (OTC 2012)

The Kansas State University (KSU) 2011 document included a database on 4,729 engines used in Exploration and Production (E&P) at major sources. LB engines accounted for 66 percent of engines (17 percent are 2S and 49 percent are 4S), and RB engines accounted for 34 percent. LB outnumbers RB among engines included in the database; because many engines rating less than 100 hp are not included, and because the majority of the smaller units are 4S RB, RB are actually underrepresented in the database. A listing of the engines (manufacturer and model), air to fuel (A/F) ratio type, cycle, and horsepower are included in Appendix I of the KSU 2011 document. The database was not meant to collect every single engine in use but rather to provide a frequency distribution of engines. The data was pulled from multiple sources, including the State of Wyoming Engine Inventory Database, EPA ICCR Database, GTI/PRCI Engine and Turbine Database, and Database of Colorado and New Mexico Engines (from Universal Compression). The engine database likely includes only permitted engines, and lower-hp engines are underrepresented in the database. (pp. 5-7) (KSU 2011)

The EDF 2008 reference indicated most engines in Barnett Shale area of Texas are 100 to 500 hp but some large engines of 1000+ hp are also used. (EDF 2008)

The EDF 2008 reference indicated that the TCEQ Point Source Emissions Inventory (PSEI) does not include a substantial fraction of compressor engine emissions. Most of the missing engines in the DFW NAA were units with emissions below the reporting thresholds, but the combined emissions from large numbers of these engines can be substantial (pp. 13-14). The 2007 DFW Engine survey indicated there were approximately 680,000 hp of installed engine capacity in DFW NAA not previously reported to the TCEQ PSEI (p. 14). The report also estimated that there is approximately 132,000 hp of engines in Attainment Area (AA) counties within the Barnett Shale that don't report to PSEI (non-PSEI) (p. 14). The LB and RB engine data from the 2007 DFW Engine Survey for the DFW NAA is provided in the table below. In this survey, there seem to be fairly even numbers of LB (51%) and RB (49%) engines in the >500 hp category, and there seems to be fairly even horsepower capacity for the LB and RB engines. For smaller engines that are <500 hp, there are significantly more RB engines (736 engines, or 96%) than LB engines (27 engines, or 4%). In addition, for the smaller engines <500 hp, the horsepower capacity for RB represents 15% and for LB is <1%. (EDF 2008)

Installed Engine Capacity in 2007 DFW Engine Survey by Engine Type and Size, in DFW NAA (EDF 2008)

Engine Type	Engine Size, hp	Number of Engines	Percent of Engines, %	Typical Size, hp	Installed Capacity, hp	Percent of Installed Capacity, %
RB	<50	12	1.03%	50	585	0.086%
RB	50–500	724	62%	140	101,000	15%
RB	>500	200	17%	1,400	280,000	41%
LB	<500	27	2.3%	185	4,940	0.72%
LB	>500	206	18%	1,425	294,000	44%

The EDF 2008 reference looked at all of the compressor engines in the Barnett Shale region, including both the engines located within the DFW NAA and the engines in the DFW AA (including those larger engines that report to the PSEI and those non-PSEI engines). New TCEQ rules became effective in 2009 to reduce NOx from the subset of engines located in the DFW NAA that typically are not reported to the PSEI (due to their small size) for major sources (p. 25). Engines that are located outside the DFW NAA are not subject to the 2009 rule. As shown in the table below, a 50% reduction of emissions from 2007 to 2009 was estimated in DFW NAA, taking into account the growth, regulation affect, and NSCR installations. For AA engines, emissions will increase from 2007 to 2009 due to growth and the fact that no regulation applies (these engines not subject to 2009 engine regulation) (p. 19). (EDF 2008)

NOx Emissions from Compressor Engines in Barnett Shale of Texas (EDF 2008)

Area	2007 NOx Emissions, tpd	2009 NOx Emissions, tpd
DFW NAA engines	32	16
AA engines	20	31
Barnett Shale engines, total	52	47

The reference then looked at emission reductions for extending the 2009 rule to all engines in the Barnett Shale (including those in the AA). By extending the 2009 engine rule, NOx emissions from AA engines would drop by approximately 6.5 tpd (p.25) (this approach reduces emissions from a large number of engines, in particular RB engines between 50 to 500 hp). (EDF 2008)

The ETCG 2013 reference indicated that analysis of test reports at the TCEQ Tyler office showed 68 compressor engines: 9 engines (13%) <240 hp and 59 engines (87%) ≥240 hp (and 69% of all engines ≥500 hp) (p.11). (A graph showing the distribution of the hp for all 68 engines is shown on p.12 of the reference document.) (ETCG 2013)

The ETCG 2013 reference discussed TCEQ Barnett Shale Special Inventory (Phase I) survey data. The table below is a summary of the engine horsepower distribution. (A graph showing the distribution of NG engines in the Barnett Shale region is shown in Figure 5-1 on p. 21 of the reference document.) The majority of engines in the Barnett Shale are RB and are <240 hp, see the two tables below. This data set shows that smaller hp engines are predominantly RB, with 2,089 engines <240 hp are RB (95%) and 104 engines (5%) are LB. For engines >240 hp, 327 engines (59%) are LB and 230 engines (41%) are RB.

2009 Equipment Inventory of Stationary NG Engines by Horsepower for Barnett Shale Region. (ETCG 2013)

Engine Size	Total Engines	Percent of Total Engines	Engine Type, RB or LB	Number of Engines	Percent of Each Size Category
0 to 50 hp	317	12%	RB	302	95%
			LB	15	4.7%
50 to 240 hp	1,876	68%	RB	1,787	95%
			LB	89	4.7%
>240 hp	557	20%	RB	230	41%
			LB	327	59%

Barnett Shale Special Inventory Phase I Equipment Survey Data on Stationary Gas-Fired Engines for 2009. (ETCG 2013)

Engine counts		
<240 hp	**≥240 hp**	**Total**
RB and LB		
2,193	557	2,750
RB only		
2,089	230	2,319
LB only		
104	327	431

The CO DPHE reference indicates that large NG RICE represent 16% of the statewide point source NOx emissions (16,199 tpy of 101,818 tpy) and 73% of the ICE NOx emissions (16,199 tpy of 22,210 tpy) (p. 1). (CO DPHE)

Example Emissions Estimates: It is difficult to draw conclusions for the emissions from LB versus RB from the data provided. However, some assumptions could be made to help draw conclusions for the defined scenario. If assume that the total capacity between LB and RB in the ERLE study is more representative of the total reporting population than the 50–50 split in the EDF study; assume that operating hours are similarly distributed for both LB and RB; and if the EFs tend to be higher for LB than for RB engines, then it is likely that 90% plus of the total emissions are from LB.

References

(CARB 2001). *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines*. California Environmental Protection Agency, Air Resources Board, Stationary Source Division, Emissions Assessment Branch, Process Evaluation Section. November 2001.

(IEPA 2007). Technical Support Document for Controlling NOx Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines. AQPSTR 07-01. Illinois Environmental Protection Agency, Air Quality Planning Section, Division of Air Pollution Control, Bureau of Air. March 19, 2007.

(EPA 2003). Stationary Reciprocating Internal Combustion Engines: Technical Support Document for NOx SIP Call. U.S. Environmental Protection Agency. D. Grano and B. Neuffer. October 2003.

(EDF 2008). *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost Effective Improvements.* Conducted by Department of Environmental and Civil Engineering, Southern Methodist University, for Environmental Defense Fund. Peer-Review Draft. September 30, 2008.

(KSU 2011). *Final Report: Cost-Effective Reciprocating Engine Emissions Controls and Monitoring for E&P Field and Gathering Engines*. K. Hohn and S. Nuss-Warren, Kansas State University. November 2011.

(OTC 2012). *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final.* October 17, 2012. [This document focuses on Offshore Gulf of Mexico, Rocky Mountains, Southwest, and Mid-Continent areas.]

(ETCG 2013). *Gas Compressor Engine Study for Northeast Texas, for East Texas Council of Governments*. Prepared by ENVIRON International Corporation, for East Texas Council of Governments. June 2013.

(CO DPHE). *Reciprocating Internal Combustion Engine (RICE) Source Category, Reasonable Progress Evaluation for RICE Source Category*. Colorado Department of Public Health and Environment—Air Pollution Control Division.

EPA Question 3: What is the effect of NOx SIP call controls on RICE in NOx SIP call states? That is, what percent reduction and types of controls have gone into place in states affected by the NOx SIP call?

Notes for Question 3

The applicability, reduction achieved, and cost for RICE NOx controls are often engine specific and highly variable. (DE 2012) (OTC 2012)

Common NOx control techniques are provided in the table below, along with NOx emission reductions achievable. (References from other areas outside of the NOx SIP call states also provided details on controls and emissions reductions achieved by these controls and are included in the table.)

Effectiveness of Combustion Control Technologies and Add-On Controls

Control Technique	(OTC 2012)	(KSU 2011)	(CARB 2001)	(CO DPHE)
2 Stroke, LB				
Improved combustion air flow, Turbocharger	(p. 18, 31): up to 75%	Up to 90%; 0.5 to 2 g/bhp-hr (increases fuel economy; may increase CO) (p. 9)	—	—
Retard ignition timing	(p. 54): diesel, 10% (reduces engine efficiency; increases PM)	Up to 10% (increase fuel economy; may increase CO) (p. 9)	(p. B-7,8): 15 to 30% (increases fuel consumption; increases VOC, HAP)	20% (pp. 5-7); $310 to $2,000/ton (p. 8)
Improved air fuel mixing, High Pressure Fuel Injection	(p. 18, 31): up to 90%	—	—	—
Advanced In-cylinder mixing	—	30 to 70% (p. 11)	—	—
Precombustion chamber (PCC) ignition system	(p. 19, 31-32): up to 90%	1 g/bhp-hr (p. 10)	—	—
Micro Precombustion chamber (MPCC), hybrid of High energy Ignition system and PCC	—	2 to 4 g/bhp-hr (p. 10)	—	—
Screw-in PCC	—	1 g/bhp-hr (p. 10)	—	—
Autobalance cylinders	(p. 23): not provided	—	—	—

(continued)

Effectiveness of Combustion Control Technologies and Add-On Controls (continued)

Control Technique	(OTC 2012)	(KSU 2011)	(CARB 2001)	(CO DPHE)
2 Stroke, LB (cont.)				
Air to Fuel Ratio Controller (AFRC)	(p. 19, 32): not provided	Not provided; use in combo with Increased air flow, or postcombustion Catalyst; a few thousand $ for small engine to $30K for larger engines (p. 12).	(p. B-8): not provided (fuel consumption penalty of 3%; may increase CO, VOC)	5 to 30% (pp. 5-7); $320 to $8,300/ton (p. 7)
Combustion modifications, Layered Combustion controls	(p. 25): 60 to 90%; range of 0.5 to 3 g/bhp-hr	—	—	—
4 stroke, LB				
EGR and NSCR	(p. 32): (emissions lower than SCR)[a]	—	—	—
Combustion modifications, Layered Combustion controls	(p. 38): 90%; range of 0.5 to 2 g/bhp-hr	—	—	—
Engines (general) or LB				
High energy ignition system (HEIS)	(p. 18, 31, 44): 10%	2.5 to 3 g/bhp-hr (pp. 9-10)	(p. B-12): 200 ppm NOx	—
Low emission combustion (LEC)/precombustion chamber retrofit (PCC) [also applicable to RB]	—	—	(p. B-10): 80% (may increase VOC, CO)	—
Turbocharging/ supercharging, and Aftercooling	(p. 18): Up to 75%	—	(p. B-13): 3 to 35% for Aftercooling (may reduce VOC, CO; increases engine efficiency, power rating)	—
EGR	(p. 55): diesel, >40% (loss of fuel efficiency; loss of engine output)	Still under development for NG engines; not cost effective at this time (p. 11).	(p. B-14): 30% (reduces engine peak power; reduces fuel efficiency by 2 to 12%)	—
Ignition system improvement	—	—	(p. B-11-2): not provided (may increase VOC, CO)	—

(continued)

Effectiveness of Combustion Control Technologies and Add-On Controls (continued)

Control Technique	(OTC 2012)	(KSU 2011)	(CARB 2001)	(CO DPHE)
Engines (general) or LB (cont.)				
Homogeneous charge compression ignition (HCCI), combines best features of SI and CI engines	—	Still in R&D phase, no reduction or cost info available (reduces PM; high efficiency) (p. 11-12).	—	—
Fuel switching, Hydrogen/NG blended fuel	—	40 to 50% (p. 12) Still under development, no cost info available; use of H_2 blend removes need for PCC; H_2 fuel would need to be available in the field.	—	—
Selective Catalytic Reduction (SCR)	(p. 19, 32, 55): 50 to 95% (reduces THC, CO)	80 to 90% (can release NH3) (p. 13)	(p. B-23): >80%	80 to 90% (pp. 5-7); $430 to $4,900/ton (p. 9)
Lean-NOx catalysts	(p. 55): diesel, 10 to 50%	Up to 80% (reduces CO, HC by 60%; reduces fuel economy by 3%) (p. 14)	(p. B-24): diesel, 25 to 50% (increases fuel consumption; may increase VOC, PM)	—
NOxTech	—	—	(p. B-25): 80 to 90%; (decreases CO, VOC, PM by 80%; fuel penalty 5 to 10%)	—
Lean NOx traps	(p. 55): diesel, up to 90%	—	—	—
NOx Adsorber Technology (SCONOx)	—	—	(p. B-27): >90% on diesel engine <100 hp; [2 ppmv on NG turbine]	—
Selective noncatalytic reduction (SNCR) [also applicable to RB]	—	—	—	50 to 95% (pp. 5-7)

(continued)

Effectiveness of Combustion Control Technologies and Add-On Controls (continued)

Control Technique	(OTC 2012)	(KSU 2011)	(CARB 2001)	(CO DPHE)
Engines (general) or LB (cont.)				
Fuel switching, methanol	—	—	(p. B-16): 30% for conversion from NG to methanol (can generate formaldehyde emissions)	—
Hybrid system, modification of dual bed NSCR system	—	—	(p. B-22): 3 to 4 ppm NOx	—
Use of electric motors in place of combustion engines	—	—	(p. B-27): >60%	60 to 100% (pp. 5-7); $100 to $4,700/ton [not include full costs] (p. 9)
RB				
Nonselective catalytic reduction (NSCR) plus AFRC	(p. 45, 49-51): 90 to 99% (reduces CO, VOC)	>90%, < 1 g/bhp-hr (reduces CO, HC) (p. 13)	(p. B-19-20): >90% (reduces CO >80%; reduces CO>50%; increases fuel consumption)	80 to 90% (pp. 5-7); Capital cost is $35,000; O&M is $6,000; Annualized capital is $4,851; TAC is $10,851; $571/ton (p. 8)
Convert RB to LB	(p. 45): not provided	—	—	—
EGR	(p. 49): up to 80% (increase power output by 10%; decrease fuel consumption by 7%)	—	—	—
Pre-stratified charge (converts RB to LB)	—	For 4S, RB, 2 g/bhp-hr (may de-rate engine power by 20%; costs significant) (p. 11)	(p. B-15): >80% (improved fuel efficiency)	—

[a]Some industry literature suggests that some particular 4S RB SI reciprocating engines can be converted to LB configurations with the accompanying LB engine NOx reduction capabilities. One vendor indicates that conversion to a LB configuration and the use of exhaust gas recirculation (EGR) delivers the advantages of a LB engine's efficiency and the RB engine's capability of utilizing NSCR for NOx control. The ability to convert a RB engine to a LB configuration is highly unit specific and does appear to have had widespread application in industry (p. 45). (OTC 2012)

Illinois: IEPA projected 2007 NOx emissions from 28 engines subject to the NOx SIP call to be 6,618 ton/season. NOx emission reductions from these sources were estimated to be 5,422 ton/season, and controlled NOx emissions levels were estimated to be 1,196 ton/season. (So baseline emissions were estimated to be 6,618 ton/season and controlled emissions were estimated to be 1,196 ton/season.) (IEPA 2007)

IEPA 2002 base year emissions inventory was 23,347 tpy NOx emitted from RICE and turbines, or approximately 8.4 percent of total point source NOx emissions (277,899 tpy NOx emissions from all point sources in Illinois) (p. 12). (IEPA 2007)

In addition to the NOx SIP Call requirements, IEPA also included additional units in its NOx regulation. NOx SIP Call units were to comply by May 2007, and additional units in NAA and AA were to comply in 2009, 2011, and 2012 (p. 51). The IL regulation will potentially affect 202 RICE engines and 36 turbines and reduce NOx emissions by 5,422 ton/season in 2007 ozone control season (p. 10). (IEPA 2007) [Full implementation of the IL regulation in 2012, to include additional units in NAA and AA counties down to the 500 hp size [28 NOx SIP Call units plus an additional 246 engines], was projected to reduce NOx emissions statewide by 17,082 tpy and 7,206 ton/season, which is 65 percent reduction on an annual basis and 55 percent reduction in O_3 season emissions (pp. 11 and 56). Uncontrolled NOx emissions in 2012 were projected to be 21,532 tpy and 9,134 ton/season, for those units included under the full implementation of the rule (p. 56). (IEPA 2007)]

Other Available Information

Additional RB control technologies and data are available in the OTC 2012.

Additional Diesel control technologies and data are available in OTC 2012.

References

(CARB 2001). *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines*. California Environmental Protection Agency, Air Resources Board, Stationary Source Division, Emissions Assessment Branch, Process Evaluation Section. November 2001.

(IEPA 2007). *Technical Support Document for Controlling NOx Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines*. AQPSTR 07-01. Illinois Environmental Protection Agency, Air Quality Planning Section, Division of Air Pollution Control, Bureau of Air. March 19, 2007.

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(DE 2012) *Background Information, Oil and Gas Sector, Significant Sources of NOx Emissions*. Delaware Department of Natural Resources and Environmental Quality.

(OTC 2012). *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final*. October 17, 2012.

(CO DPHE). Reciprocating Internal Combustion Engine (RICE) Source Category, Reasonable Progress Evaluation for RICE Source Category. Colorado Department of Public Health and Environment – Air Pollution Control Division.

EPA Question 4: What are typical or realistic baseline and controlled NOx emissions factors (grams/hp-hr) for RICE in the OTC states?

Notes for Question 4

NOx control requirements for several of the Ozone Transport Commission (OTC) states were provided for Connecticut, New Jersey, New York, and Rhode Island, based on a 1994 STAPPA/ALAPCO document (p. 45). (IEPA 2007) These could potentially be used as maximum EF for RICE units. NOx control requirements are listed in the following table.

NOx Control Requirements for RICE in Some OTC States and Other States

State	Covered	NOx Control Level	Reference
Connecticut	≥3 MMBtu/hr (1175 hp)	Liquid-fired, CI: 8 g/bhp-hr (584 ppm)	IEPA 2007
New York	RACT for Major Facilities of NOx, Severe O_3 NAA ≥200 hp and Rest of state ≥400 hp	▪ Thru March 31, 2005, NG, RICE, LB: 3 g/bhp-hr (220 ppm) ▪ After April 1, 2005, LB: 1.5 g/bhp-hr (110 ppm) ▪ Thru March 31, 2005, Liquid-fired, CI: 9 g/bhp-hr (657 ppm) ▪ After April 1, 2005: 2.3 g/bhp-hr (168 ppm)	OTC 2012, DE 2012, IEPA 2007
New York (RACT)	Major facilities >25 tpy, NYC and Lower Orange Co: ≥200 kW Rest of state, major facilities >100 tpy: ≥400 kW	▪ NG: 1.5 g/bhp-hr ▪ Landfill or digester gas: 2.0 g/bhp-hr	
New Jersey		▪ NG, LB, ≥500 hp: 2.5 g/bhp-hr (182 ppm) ▪ Liquid-fired, CI, ≥500 hp: 8 g/bhp-hr (584 ppm)	IEPA 2007
New Jersey (RACT)	≥148 kW Group of 2 or more engines, each at ≥37 to <148 kW, but total combined power ≥148 kW	▪ Gas, LB: 1.5 g/bhp-hr, or 80% reduction ▪ Gas, RB: 1.5 g/bhp-hr	
New Jersey (RACT)	≥37 kW	▪ Commenced on or after March 7, 2007: 0.9 g/bhp-hr ▪ Modified on or after March 7, 2007: 0.9 g/bhp-hr, or 90% reduction	
Maryland	NG pipeline engines with >15% capacity factor	NA	IEPA 2007
Other States and Areas			
Illinois	NA	▪ 3 g/bhp-hr (210 ppm)	NA

(continued)

NOx Control Requirements for RICE in Some OTC States and Other States (continued)

State	Covered	NOx Control Level	Reference
Other States and Areas (cont.)			
SJVAPCD (amended 2011Aug18)	Rule 4702 ICE, SI and CI, nameplate rating ≥25 hp	▪ 2S, LB, NG, <100 hp: 75 ppmvd ▪ LB limited use or Gas compression: 65 ppmvd ▪ LB, all others: 11 ppmvd	OTC 2012
Texas	Oil & Gas Handling and Production Facilities	▪ 2S, SI, LB, ≥500 hp: – Mfg before 9/23/1982: 8 g/bhp-hr – Mfg before 6/18/1992, <825 hp: 8 g/bhp-hr – Mfg btwn 9/23/1982 and 6/18/1992, >825hp: 5 g/bhp-hr – Mfg btwn 6/18/1992 and 6/1/2010: 2 g/bhp-hr (except 5 g/bhp-hr at reduced speed and torque 80-100%) – Mfg after 6/1/2010: 1 g/bhp-hr	OTC 2012
Texas	Oil & Gas Handling and Production Facilities	▪ 4S, SI, LB: – Mfg before 9/23/1982, ≥500hp: 5 g/bhp-hr (except 8 g/bhp-hr at reduced speed and torque 80-100%) – Mfg before 6/18/1992, <825 hp: 5 g/bhp-hr (except 8 g/bhp-hr at reduced speed and torque 80-100%) – Mfg btwn 9/23/1982 and 6/18/1992, >825hp: 5 g/bhp-hr – Mfg btwn 6/18/1992 and 6/1/2010, ≥500hp: 2 g/bhp-hr (except 5 g/bhp-hr at reduced speed and torque 80-100%) – Mfg after 6/1/2010, ≥500hp: 1 g/bhp-hr ▪ After 1/1/2030, no 4S LB SI engine NOx emissions shall exceed 2 g/bhp-hr regardless of manufacture date.	OTC 2012
Texas	Oil & Gas Handling and Production Facilities	▪ 4S SI, LB, <500hp: ▪ Mfg before 7/1/2008: 2 g/bhp-hr ▪ After 1/1/2030: no 4S LB SI engine NOx emissions shall exceed 2 g/bhp-hr regardless of manufacture date.	OTC 2012
Texas (NAA major sources)	RACT, Major ICI, O3 NAA, Beaumont-Port Arthur O_3 NAA Major sources	▪ NG, SI, RICE, LB ≥300 hp: 3 g/bhp-hr ▪ NG, SI, RICE, RB, ≥300 hp: 2 g/bhp-hr	OTC 2012, DE 2012
Texas (NAA minor sources)	Combustion Control at Minor Sources in O_3 NAA, Houston-Galveston-Brazoria	▪ NG, RICE, >50 hp: 0.5 g/bhp-hr	DE 2012, ETCG 2013
Texas	O3 NAA, Dallas Ft. Worth	▪ RB, >50 hp: 0.5 g/hp-hr ▪ LB, >50 hp: – Installed or moved before June 2007: 0.7 g/hp-hr – Installed or moved after June 2007: 0.5 g/hp-hr	EDF 2008; ETCG 2013

(continued)

NOx Control Requirements for RICE in Some OTC States and Other States (continued)

State	Covered	NOx Control Level	Reference
Other States and Areas (cont.)			
Texas	East Texas Combustion Rule (existing engines comply by March 1, 2010; new engines comply at startup.)	▪ RB, NG, RICE, 240 to 500 hp: 1 g/hp-hr ▪ RB, NG, RICE, ≥500 hp: 0.5 g/hp-hr ▪ RB, Landfill gas, RICE, ≥500 hp: 0.6 g/hp-hr	ETCG 2013
Colorado	Regulation 7, RICE, LB, NG, New, modified, relocated	▪ After July 1, 2007, ≥500 hp: 2 g/bhp-hr ▪ After July 1, 2010, ≥500 hp: 1 g/bhp-hr ▪ After January 1, 2008, 100 to 500 hp: 2 g/bhp-hr ▪ After January 1, 2011, 100 to 500 hp: 1 g/bhp-hr	OTC 2012; CO DPHE
USEPA Part 60, subpart JJJJ (NSPS) (final 2008Jan18)	NG, SI, ICE	▪ Mfg after 7/1/2008, ≤25 hp, Class I: 11.0 g/hp-hr of NMHC + NOx combined ▪ Mfg after 7/1/2008, ≤25 hp, Class I-B: 27.6 g/hp-hr of NMHC + NOx combined ▪ Mfg after 7/1/2008, ≤25 hp, Class II: 8.4 g/hp-hr of NMHC + NOx combined ▪ Mfg after 7/1/2008, 25 to 100 hp: 2.8 g/hp-hr of HC + NOx combined	ETGC 2013
USEPA Part 60, subpart JJJJ (NSPS) (final 2008Jan18)	SI, NG and SI, LB, LPG, 100 to 500 hp	▪ Mfg after 7/1/2008: 2 g/bhp-hr ▪ Mfg after 1/1/2011: 1 g/bhp-hr	ETCG 2013
USEPA Part 60, subpart JJJJ (NSPS) (final 2008Jan18)	NG and LPG, SI, LB, 500 to 1350 hp	▪ Mfg after 7/1/2008: 2 g/bhp-hr ▪ Mfg after 7/1/2010: 1 g/bhp-hr	OTC 2012
USEPA Part 60, subpart JJJJ (NSPS) (final 2008Jan18)	SI, NG and SI, LB, LPG (except LB 500 to 1350 hp)	▪ Mfg after 7/1/2007: 2 g/bhp-hr	ETCG 2013

NOx Control Requirements for RICE in Local Areas.

State or Area	Criteria	NOx control level	Reference
SCAQMD (July 2010)	Rule 1110.2 Emissions from Gaseous and Liquid Fueled Engines	▪ ≥500 hp: 0.5 g/bhp-hr (36 ppmvd) ▪ <500 hp: 0.6 g/bhp-hr (45 ppmvd) ▪ After July 1, 2010, ≥500 hp: 0.15 g/bhp-hr (11 ppmvd) ▪ After July 1, 2010, <500 hp: 0.6 g/bhp-hr (45 ppmvd) ▪ After July 1, 2011, All: 0.15 g/bhp-hr (11 ppmvd)	OTC 2012

For engines with unknown pre-rule emissions, NOx emissions were assumed to be 16.4 g/bhp-hr for 2S and 18.9 g/bhp-hr for 4S. (DE 2012)

A list of Stack test results for engines in PA that are >500 hp are given in Appendix A, Table 3 of the PA DEP 2013 reference (p. 53). (PA DEP 2013) [Capital] costs for NSCR, RB ranged from $10 to $12/bhp. (p. 9) NSCR, RB ranged from $10 to $15/bhp (slightly different value given here). (p. 16) (MECA 1997)

IC Engine Typical Emissions Levels (MECA 1997)

Engine Type	Lambda (Actual A/F ratio to Stoichiometric A/F ratio)	Mode	NOx, g/bhp-hr
NG	0.98	Rich	8.3
	0.99	Rich	11.0
	1.06	Lean	18.0
	1.74	Lean	0.7
Diesel	1.6–3.2	Lean	11.6
Dual Fuel	1.6–1.9	Lean	4.1

For RB, CARB 2001 document has Costs for NSCR w/o AFRC achieving 96% reduction. Capital costs ranged from $11,000 to $44,000; Annual costs ranged from $8,200 to $18,000; and cost effectiveness ranged from $2,100/ton to $300/ton NOx reduction (p. V-2 to V-3). (CARB 2001)

For RB, CARB 2001 document has Costs for Pre-stratified Charge, achieving 80% reduction. Capital costs ranged from $10,000 to $47,000; Annual costs ranged from $2,700 to

$11,000; and cost effectiveness ranged from $800/ton to $200/ton NOx reduction (pp. V-2 to V-3). (CARB 2001)

CARB 2001 document has costs for Ignition Timing Retard (ITR), although the description of the combustion technology indicates it is less popular on Stationary engines than mobile source engines (pp. V-2, B-7 to B-8). (CARB 2001)

The EDF 2008 reference provided NOx EF for engines in the Bartlett Shale region. The document notes that extending the 2009 engine rules in Barnett Shale to counties outside the DFW NAA would likely result in many engine operators installing NSCR on RB engines. NSCR costs were cited as follows: $330/ton (IEPA 2007); $92 to $105/ton (EPA 2006); and $112 to $183/ton (northeast Texas 2005 report). Another control technique reviewed in this report included replacement of compressor engines with electric motors. There are multiple compressors driven by electric motors throughout Texas (p. 26). Use of electric motors instead of gas-fired engines eliminates combustion emissions (p. 27). The costs are time and site specific, based on the cost of electricity, cost of NG, hours of operation per year, number of compressors, size of compressor, etc. (EDF 2008)

NOx Emission Factors for Engines Identified in DFW 2007 Engine Survey (EDF 2008)

2007 EF			2009 EF		
Engine Type	**Engine Size, hp**	**NOx, g/hp-hr**	**Engine Type**	**Engine Size, hp**	**NOx, g/hp-hr**
RB	<50	13.6	RB	<50	13.6
RB	50–500	13.6	RB	50–500	0.5
RB	>500	0.9	RB	>500	0.5
LB	<500	6.2	LB, installed or moved before June 2007	<500	0.62
LB	>500	0.9	LB, installed or moved after June 2007,	<500	0.5
___	___	___	LB, installed or moved before June 2007	>500	0.7
___	___	___	LB, installed or moved after June 2007	>500	0.5

References

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(CARB 2001). *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines*. California Environmental Protection Agency, Air Resources Board, Stationary Source Division, Emissions Assessment Branch, Process Evaluation Section. November 2001.

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(OTC 2012). *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions*. Final. October 17, 2012.

PA DEP 2013. Technical Support Document General Permit GP-5. Pennsylvania Department of Environmental Protection, Bureau of Air Quality. January 31, 2013.

(ETCG 2013). *Gas Compressor Engine Study for Northeast Texas, for East Texas Council of Governments*. Prepared by ENVIRON International Corporation, for East Texas Council of Governments. June 2013.

(CO DPHE). *Reciprocating Internal Combustion Engine (RICE) Source Category, Reasonable Progress Evaluation for RICE Source Category*. Colorado Department of Public Health and Environment—Air Pollution Control Division.

EPA Question 5: Using FERC data or other data sources, what is the relationship between RICE model and age, and emissions (both for baseline and with controls)? In particular, what is the relationship for RICE built before the imposition of the SI (spark ignition, natural gas-fired) RICE NSPS in 2007?

Notes for Question 5

The DE 2012 reference stated that many of the installed mainline NG compressors are of the age (in excess of 40 years old) to have pre-dated modern original equipment manufacturer (OEM) installed NOx emission controls and otherwise applicable new source performance standards (NSPS). There is little information on the number of units that may have undergone NOx modifications as a result of federal or State rules and regulations. The reference cited a 2003 Pipeline Research Council International (PRCI) document that identified 5,686 engines: 71% are LB and 29% are RB (based on dropping the turbine numbers in the table below). The average age for each unit type is shown in the following table. [These data are repeated in OTC 2012.] [Based on these data, it is estimated that the LB and RB engines are 37 years old on average (based on dropping the turbine numbers in the table below).] (p. 19) (DE 2012)

2003 Pipeline Research Council International Data (PRCI)

Unit Type	U.S Total Units (%)	Average Age (as of 2003)	Avg hp
2S LB	2,955 (44%)	42	2,113
4S LB	1,059 (16%)	33	1,844
RB	1,672 (25%)	32	589
Turbine	1,016 (15%)	24	6,121

The OTC 2012 reference indicated that many of the reciprocating engines driving mainline NG compressors are in excess of 40 years old, pre-dating any applicable modern OEM installed NOx emission control and any otherwise applicable NSPS NOx controls (p. 16). (OTC 2012)

The DE 2012 reference discussed a 2005 study conducted for NG field gathering engines in Eastern Texas; the study was able to determine the age only for a very small portion of the engines, and the engine age ranged from 2 to 25 years. The output ratings of engines in the study ranged from 26 to 1478 hp, with the majority rated between 50 and 200 hp (p. 12). (DE 2012)

The DE 2012 reference indicated they reviewed MARAMA's 2007 Point Source Inventory and 2007 FERC data. The 2007 FERC data are provided as Attachment III to the reference. The two sets of data did not match: 2007 MARAMA data indicated 107 compressor facilities, and 2007 FERC data indicated 150 compressor facilities. The reviewed databases did not provide any information regarding NOx emission rates (g/bhp-hr, ppmvd). NOx emission rates were obtained for a small number of prime movers, through operating permits: 2SLB range from 1 to 13.3 g/bhp-hr; 4SLB range from 0.5 to 6 g/bhp-hr; and 4SRB were 3 g/bhp-hr. The data are not sufficient to estimate actual NOx emission rates and NOx reductions. Note that the FERC data addresses large entities, and smaller companies may not be required to report data to FERC. The 2007 OTC compressors from FERC are provided in the following table. (DE 2012)

State	No. Compressors	Total Rated hp
CT	10	35,300
MA	15	25,702
MD	17	52,250
ME	4	33,244
NJ	36	129,130
NY	120	359,487
PA	467	1,331,164
RI	6	29,170
VA (OTR area only)	22	49,390

The KSU 2011 reference discussed control technologies testing performed in the laboratory on a 1966 Ajax DP-115 (Lean Burn) that has none of the low emissions controls that are currently OEM standard. The published emission factor (EF) for this engine is 4.4 g/bhp-hr, and the emissions from actual testing were 4.69±0.18 g/bhp-hr (the Lab testing results are discussed on pp. 19-27). There is additional discussion of Field testing conducted on multiple LB engines with NOx emission control techniques, including (1) Increased air flow, and precombustion chamber (PCC) screw-in type, (2) PCC screw-in type and Upgraded turbocharger, (3) Integral PCC and high-output turbocharger (pp. 27-29). Discussion of Field testing conducted on two RB engines with NOx emission control techniques (p. 29). Integrated nonselective catalytic reduction (NSCR) with modeling and enhanced controller is also discussed. (KSU 2011).

References

(KSU 2011). *Final Report: Cost-Effective Reciprocating Engine Emissions Controls and Monitoring for E&P Field and Gathering Engines*. K. Hohn and S. Nuss-Warren, Kansas State University. November 2011.

(DE 2012) *Background Information, Oil and Gas Sector, Significant Sources of NOx Emissions*. Delaware Department of Natural Resources and Environmental Quality.

(OTC 2012). *Technical Information Oil and Gas Sector, Significant Stationary Sources of NOx Emissions. Final.* October 17, 2012.

EPA Question 6: What is the variability in NOx emissions from RICE within each State, both for baseline and with controls?

Notes for Question 6

No data were found. [Likely a review of RICE SCCs in the NEI across states would be a useful exercise to see the relative levels of baseline and/or controlled NOx emissions, however this exercise was not part of this task.]

To: US EPA OAQPS

From: SRA International, Inc.

Subject: Review of CoST Model Emission Reduction Estimates

Date: September 30, 2014

EPA uses the Control Strategy Tool (CoST) to estimate the emission reductions and engineering costs associated with control strategies applied to point, area, and mobile sources of air pollutant emissions to support the analyses of air pollution policies and regulations. CoST accomplishes this by matching control measures to emission sources using algorithms such as "maximum emissions reduction", "least cost", and "apply measures in series". There was a concern that the baseline inventory used by CoST did not completely account for emission control requirements already in place, and that the emission reductions were perhaps overestimated.

SRA reviewed the CoST results and made recommendations for changing the CoST control measure assignment and the estimated reductions for oxides of nitrogen (NOx). The recommendations were based on a review of source permits, state regulations, enforcement actions, and other available information. The analysis was conducted for a 24-state area in the eastern two-thirds of the U.S. The focus was on stationary point sources other than electric generating units (non-EGUs). The purpose of this memo is to document the data used and assumptions made in recommending changes to the CoST results, and to summarize the differences between the CoST results and the recommended changes.

The findings in this memo are based on review of CoST results for a 2018 emissions inventory projected from the 2011 National Emission Inventory (NEI). This work was in support of EPA's current Transport Rule efforts for implementing the 75 ppb ozone standard. If EPA considers establishing a tighter ozone standard in the future, it is likely that a more distant future year will be used and that some of the conclusions reached in this memo could change.

CoST DATA PROVIDED BY EPA

EPA provided SRA with the outputs from a CoST scenario that identified sources for which NOx controls were available at a cost-effectiveness level of less than $10,000 per ton. The CoST outputs included source identifiers, control technology, baseline emissions and estimates of NOx emission reductions. The CoST results were divided into two groups. The first group included sources where CoST estimated NOx emission reductions of more than 100 tons per year. There were 547 sources in this group where CoST controls were initially applied. The second group included sources where CoST estimated emission reductions for sources whose 2018 projected emissions were greater than 25 tons/year, excluding those with reductions greater than 100 tons/year. There were 1,280 sources in this group where CoST controls were initially applied.

Another contractor reviewed the CoST results for additional source categories, and their recommendations were merged with SRA's recommendations in the summary tables and maps that follow. The data used, assumptions made and results for IC engines are documented elsewhere[1].

REVIEW OF CoST RESULTS FOR THE GREATER THAN 100 TPY GROUP

Table 1 summarizes the source categories included in our analysis, the CoST recommendation for NOx control, and the recommendation for changing the CoST control measure assignment and associated emission reduction estimates. Following Table 1, there is a discussion for each source group to provide more detail on the rationale for the recommended changes for each source group. Attachments 1 to 4 are tabular comparisons of the initial CoST emission reduction estimates and the recommended changes. All Attachments present the results in terms of tons per ozone season, simply estimated by assuming that ozone season emissions were equal to 5/12 of the annual emissions. Maps 1A and 1B graphically show the location of sources and the magnitude of the recommended emission reductions.

Table 1 – CoST Controls and Recommended Changes for Greater than 100 TPY Sources

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
Ammonia – NG-fired Reformers	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled.
By-Product Coke Mfg; Oven Underfiring	Selective Non-Catalytic Reduction	Review of a source-specific NOx RACT permit indicated that NOx controls were technically or economically infeasible.
Cement Kilns	Biosolid Injection Technology	Disagreed with CoST recommendation based on concerns about biosolids availability and information from EPA's ISIS (Industrial Sector Integrated Solutions) Model; recommended SNCR for all sources, except those that already have SNCR due to NOx SIP Call, NSR requirement, Consent Decree, or other state regulation.

[1] Update of NOx Control Measure Data in the CoST Control Measures Database for Four Industrial Source Categories: Ammonia Reformers, NonEGU Combustion Turbines,Glass Manufacturing, and Lean Burn Reciprocating Internal Combustion Engines," prepared by Research Triangle Institute, July 2014.

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
Cement Manufacturing - Dry	Selective Non-Catalytic Reduction	Agreed with CoST recommendation except when already controlled due to NOx SIP Call, NSR requirement, Consent Decree, or other state regulation.
Cement Manufacturing – Wet	Mid-kiln Firing	Disagreed with CoST recommendation based on information from EPA's ISIS Model; recommended SNCR for all sources, except those that already controlled
Coal Cleaning – Thermal Dryer	Low NOx Burner	Agreed with CoST recommendation
Comm/Inst Incinerators	Selective Non-Catalytic Reduction	Both sources are already controlled with SNCR
External Combustion Boilers, Elec Gen, Solid Waste	Selective Non-Catalytic Reduction	All 6 sources are already controlled with SNCR
Fluid Catalytic Cracking Units	Low NOx Burner and Flue Gas Recirculation	Nearly all FCCUs are already controlled due to the OECA global refinery consent decrees. There is one small refinery in West Texas that does not appear to be covered by a consent decree, so the CoST recommendation was accepted.
Glass Manufacturing – Container, Flat, Pressed	OXY-Firing	Disagreed with CoST recommendation. OXY-firing is not generally required under recent OECA consent decrees. More common control is oxygen-enriched air staging (OEAS). OXY-firing can only be implemented at the time of furnace rebuild, which is generally done every 10-15 years. Changed recommended control to OEAS with a 50% NOx reduction instead of OXY-firing at 85% NOx reduction, except for sources that already had NOx controls in place due to a consent decree, NSR requirement, or state regulation. Assumed that a furnace with a NOx emission limit of less than 4 lbs/ton of glass pulled was already reasonably controlled.
ICI Boilers – Coal/Cyclone	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled. LADCO/OTC also recommends SCR
ICI Boilers – Coal/Stoker	Selective Catalytic Reduction	Disagreed with CoST recommendation of SCR. CoST has $2200/ton, which appears

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
		very low for ICI boilers. Used LADCO/OTC recommendation of SNCR for Coal-Stokers with a 50% reduction, except for those sources where a permit or state regulation already required the source to be controlled.
ICI Boilers – Coal/Wall	Low NOx Burner and Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled. LADCO/OTC also recommends LNB/SCR
ICI Boilers – Gas, Natural Gas, Process Gas	Selective Catalytic Reduction	Disagreed with CoST recommendation of SCR. CoST has $3456/ton, which appears very low for ICI boilers. Used LADCO/OTC recommendation of Low NOx Burners plus Flue Gas Recirculation for Gas-fire ICI boilers with a 60% reduction, except for those sources where a permit or state regulation already required the source to be controlled
Industrial Incinerators	Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SNCR except for those sources where a permit or state regulation already required the source to be controlled.
Iron & Steel Mills – Reheating	Low NOx Burner and Flue Gas Recirculation	Agreed with CoST recommendation except for those sources where a permit or state regulation already required the source to be controlled.
Municipal Waste Combustors	Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SNCR except for those sources where a permit or state regulation already required the source to be controlled.
Nitric Acid Manufacturing	Nonselective Catalytic Reduction	Agreed with CoST recommendation of NSCR except for those sources where a permit or state regulation already required the source to be controlled.
Petroleum Refinery Process Heaters	SCR-95%	Nearly all refineries are already controlled due to the OECA global refinery consent decrees, which generally require 40-60% reductions across all boilers/heaters that each company operates. Not possible at present to identify the individual boilers/heaters that actually have been controlled or are scheduled to be controlled due to confidentiality agreements between EPA and companies.

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
Taconite Ore Processing – Induration – Coal or Gas	Selective Catalytic Reduction	Disagree with CoST recommendation of SCR. EPA Region V considers SCR/SNCR to be infeasible. Used Low NOx Burners at 70% reduction instead as reasonable control, except for those sources where a permit or state regulation already required the source to be controlled. .
Utility Boilers* – Coal/Wall	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled.
Utility Boilers* – Oil/Gas	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled.

The utility boilers included in the context of this report are non-IPM utility boilers. In the NEI, these units have an SCC of 1-01—xxx-xx (the SCC series generally used for electric generating units. However, the sources included in this analysis do not sell electricity to the grid.

Ammonia – NG-fired Reformers

There are 15 sources in this category. The CoST control technology was selective catalytic reduction (SCR) with a 90% reduction in NOx emissions. We determined that four of these sources were already controlled by either SCR or ultra-NOx burners and recommended no further control/reductions. For all other sources, we agreed with the CoST control and emission reduction estimate.

By-Product Coke Mfg; Oven Underfiring

There are 14 sources in this category. The CoST control technology was selective non-catalytic reduction (SNCR) with a 60% reduction in NOx emissions. We reviewed a detailed RACT analysis for a facility in Pennsylvania that determined that no controls were feasible. For all sources in this category, we recommended that no controls were feasible and thus no reductions were appropriate.

Cement Preheater/Precalciner Kilns

There are 36 sources in this category. The CoST control technology was biosolid injection technology with a 23% reduction in NOx emissions. We reviewed permits and consent decrees to identify those kilns that are already controlled. Several kilns are already controlled based on NOx SIP Call requirements that typically required low NOx burners, mid-kiln firing, or an approved alternative that resulted in a 30% reduction. Other kilns already had SNCR installed due to a consent decree, new source review requirement, or other state-level requirement.

EPA expressed a concern whether there was sufficient biosolids availability for use by the uncontrolled kilns. Also, EPA has done considerable research on cement kiln NOx controls as part of its Industrial Sector Integrated Solutions (ISIS) project. EPA uses the ISIS-cement model help analyze policy options for various rulemakings. Based on the ISIS work, we recommended that low-NOx burners and SNCR as the appropriate control for all types of kilns.

For uncontrolled kilns, we applied a 65% reduction in NOx emissions. For kilns already controlled with low-NOx burners or mid-kiln firing, we applied a 35% incremental reduction to account for the additional reductions from SNCR. For kilns already controlled with SNCR, we applied no additional emission reductions.

Cement Manufacturing - Dry Process

There are 20 sources in this category. The CoST control technology was SNCR with a 50% reduction in NOx emissions. We reviewed permits and consent decrees to identify those kilns that are already controlled. Several kilns are already controlled based on NOx SIP Call requirements that typically required low NOx burners, mid-kiln firing, or an approved alternative that resulted in a 30% reduction. Other kilns already had SNCR installed due to a consent decree, new source review requirement, or other state-level requirement.

As discussed earlier, we recommended that low-NOx burners and SNCR as the appropriate control for all types of kilns based on the ISIS work. For uncontrolled kilns, we applied a 65% reduction in NOx emissions. For kilns already controlled with low-NOx burners or mid-kiln firing, we applied a 35% incremental reduction to account for the additional reductions from SNCR. For kilns already controlled with SNCR, we applied no additional emission reductions.

Cement Manufacturing – Wet Process

There are seven sources in this category. The CoST control technology was mid-kiln firing with a 30% reduction in NOx emissions. We determined that two of these kilns were installing a pilot SCR system as part of a consent decree. One kiln recently went through NSR review and has state-of-the-art control. Another kiln is required to install SNCR as part of a consent decree. No additional reductions were applied for these kilns. For the remaining kilns, we applied low-NOx burners and SNCR as described in the previous sections.

Coal Cleaning – Thermal Dryer

There was one source in this category. The CoST control technology was a low-NOx burner with a 50% reduction in NOx emissions. We could not find any information on this source and accepted the CoST controls.

Comm/Inst Incinerators

There are two sources in this category. The CoST control technology was SNCR with a 45% reduction in NOx emissions. Both of these sources are already controlled by SNCR and we applied no additional emission reductions.

External Combustion Boilers, Elec Gen, Solid Waste

There are six sources in this category. The CoST control technology was SNCR with a 50% reduction in NOx emissions. All six of these sources are already controlled by SNCR and we applied no additional emission reductions.

Fluid Catalytic Cracking Units

There are six sources in this category. The CoST control technology was low-NOx burners and flue gas recirculation with a 55% reduction in NOx emissions. Nearly all sources are already controlled or required to install controls as a result of the EPA's global refinery consent decrees. There is one small refinery in West Texas that does not appear to be covered by a consent decree, so the CoST recommendation was accepted.

Glass Manufacturing – Container, Flat, Pressed

There are 65 sources in this category. The CoST control technology was oxy-firing with an 85% reduction in NOx emissions. There were several concerns about using oxy-firing for this analysis. First, there is a concern about the timing of installing oxy-firing technology. Oxy-firing is typically installed at the time of a furnace rebuild, which is typically done every 10 to 15 years. Second, oxy-firing is not generally required under recent EPA consent decrees. More common control is oxygen-enriched air staging (OEAS). We recommended that OEAS with a 50% NOx reduction instead of OXY-firing at 85% NOx reduction, except for sources that already had NOx controls in place due to a consent decree, NSR requirement, or state regulation. We assumed that a furnace with a NOx emission limit of less than 4 lbs/ton of glass pulled was already reasonably controlled.

ICI Boilers – Coal/Cyclone

There are eight sources in this category. The CoST control technology was SCR with an 80% reduction in NOx emissions. We reviewed the *Evaluation of Control Options for Industrial, Commercial and Institutional (ICI) Boilers Technical Support Document (TSD), March, 2011* prepared by the Lake Michigan Air Directors Consortium (LADCO) and the Ozone Transport Commission (OTC). LADCO/OTC also recommended SCR for coal-cyclone boilers. Since the LADCO/OTC recommendation was consistent with the CoST control, we agreed with the CoST control technology for five sources which we determined were uncontrolled. Two sources were determined to be already controlled. One source appears to have shut down their coal-fired boilers. No reductions were applied for these three sources since they are already controlled.

ICI Boilers – Coal/Stoker

There are 45 sources in this category. The CoST control technology was SCR with an 80% reduction in NOx emissions. The LADCO/OTC recommendation was for combustion tuning and SNCR. We agreed with the LADCO/OTC recommendation and assumed a 50% control efficiency. We determined that most of these sources are currently uncontrolled. Two coal-fired boilers are scheduled to be replaced with gas-fired boilers. Two other boilers recently installed SNCR.

ICI Boilers – Coal/Wall

There are 54 sources in this category. The CoST control technology was low-NOx burners and SCR with a 91% reduction in NOx emissions. The LADCO/OTC recommendation was also for low-NOx burners and SCR. Since the LADCO/OTC recommendation was consistent with the CoST control, we agreed with the CoST control technology and emission reductions.

ICI Boilers – Gas, Natural Gas, Process Gas

There are 130 sources in this category. The CoST control technology was SCR with an 80% reduction in NOx emissions. The LADCO/OTC recommendation was for low-NOx burners, flue gas recirculation, or low-NOx burners combined with flue gas recirculation. We agreed with the LADCO/OTC recommendation of low-NOx burners combined with flue gas recirculation and assumed a 60% control efficiency.

Several of these sources are located in the OTR or ozone nonattainment areas, and as a result already have a RACT control requirement or emission limitation that is consistent with the LADCO/OTC recommendations. A few of these sources are located at petroleum refineries and were assumed to be already controlled due to EPA's refinery enforcement initiative.

Municipal Waste Combustors

There are 55 sources in this category. The CoST control technology was SNCR with a 45% reduction in NOx emissions. We determined that 35 of these sources are already controlled with SNCR and no additional reductions were applied. For the remaining uncontrolled sources, we agreed with the CoST controls and emission reductions.

Nitric Acid Manufacturing

There are seven sources in this category. The CoST control technology was non-selective catalytic reduction (NSCR) with a 98% reduction in NOx emissions. All but one of these sources is already controlled by NSCR or SCR.

Petroleum Refinery Process Heaters

There are 28 sources in this category. The CoST control technology was SCR with a 95% reduction in NOx emissions. All of the sources in this category are covered sources under EPA's global refinery enforcement initiative. The settlements generally require 40-60% reductions across all boilers/heaters that each company operates. Companies have submitted NOx compliance plans to OECA that identify the specific sources that have been controlled or are planned to be controlled, along with the technology used. But it is not possible at present to identify the individual boilers/heaters that actually have been controlled or are scheduled to be controlled due to confidentiality agreements between EPA and companies. No additional reductions were included for this category.

Taconite Ore Processing – Induration – Coal or Gas

There are 10 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. All of the sources in this category are already subject to Best Available Retrofit Technology (BART) requirements under the Regional Haze program. EPA Region V determined that BART is low-NOx burners and agreed that SCR controls are infeasible for indurating furnaces. No additional reductions were included for this category.

Utility Boilers – Coal/Wall, Oil, Gas

There are 11 sources in this category. The CoST control technology was SCR with a 80 to 90% reduction in NOx emissions depending on fuel type. All of the sources in this category appear to be uncontrolled and we agreed with the CoST control and emission reduction estimate.

REVIEW OF CoST RESULTS FOR THE 25 TO 100 TPY GROUP

Due to the large number of sources in this group, we were not able to review individual permits to determine whether the individual source was already controlled. Instead, our recommendations were based on of state regulations, enforcement actions, engineering judgment, and other available information. We generally assumed that sources located in areas with stringent NOx rules are already well controlled and we assumed that no additional reductions were likely from these sources. This assumption was generally applied in New Jersey, New York and sources located in the Houston nonattainment area. Given more time, we would like to have also applied this assumption in other areas with stringent existing regulations, such as Chicago, Milwaukee, and Baton Rouge. In any future analysis, it would be useful to examine the stringency of rules that apply strictly to nonattainment areas.

Table 2 summarizes the source categories included in our analysis, the CoST recommendation for NOx control, and the recommendation for changing the CoST control measure assignment and associated emission reduction estimates. Following Table 2, there is a discussion for each source group to provide more detail on the rationale for the recommended changes for each source group. Attachments 5 to 8 are tabular comparisons of the initial CoST emission reduction estimates and the recommended changes. All Attachments present the results in terms of tons per ozone season, simply estimated by assuming that ozone season emissions were equal to 5/12 of the annual emissions. Maps 3A and 3B graphically show the location of sources and the magnitude of the recommended emission reductions.

Table 2 – CoST Controls and Recommended Changes for 25 to 100 TPY Sources

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
Ammonia – NG-fired Reformers	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a permit or state regulation already required the source to be controlled.
Cement Kilns	Biosolid Injection Technology	Because of low emissions, assume that the kiln is already controlled or have very low usage which would result in a unreasonably high cost-effectiveness
Cement Manufacturing – Wet	Mid-kiln Firing	Because of low emissions, assume that the kiln is already controlled or have very low usage which would result in a unreasonably high cost-effectiveness
Ceramic Clay Mfg; Drying	Low NOx Burner	Questions about technical feasibility for these category, assume zero reductions
Coal Cleaning – Thermal Dryer	Low NOx Burner	Agree with CoST recommendation
Comm/Inst Incinerators	Selective Non-Catalytic Reduction	Agree with CoST recommendation
External Combustion Boilers, Elec Gen, Sub/Bit Coal	Selective Non-Catalytic Reduction	Agree with CoST recommendation, although questions as to whether the source is already controlled or very low usage which would result in a unreasonably high cost-effectiveness
Fluid Catalytic Cracking Units	Low NOx Burner and Flue Gas Recirculation	Nearly all FCCUs are already controlled due to the OECA global refinery consent decrees.
Gas Turbines	Low NOx Burners	Agreed with CoST recommendation except for those sources where a state regulation already required the source to be controlled.
Glass Manufacturing – Container, Flat, Pressed	OXY-Firing	Because of low emissions, assume that the furnace is already controlled or have very low usage which would result in a unreasonably high cost-effectiveness
ICI Boilers – Coal/Stoker	Selective Catalytic Reduction	Disagreed with CoST recommendation of SCR. CoST has $2200/ton, which appears very low for ICI boilers. Used LADCO/OTC recommendation of SNCR for Coal-Stokers with a 50% reduction, except for those sources where a state regulation already required the source to be controlled.
ICI Boilers – Coal/Wall	Low NOx Burner and Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a state regulation already required the source to be

Source Group	CoST Control Recommendation	Summary of Recommended Changes to CoST Controls and Reductions
		controlled. LADCO/OTC also recommends LNB/SCR
ICI Boilers – Distillate Oil or Process Gas	Selective Catalytic Reduction	Because of low emissions, assume that the boiler is already controlled or have very low usage which would result in a unreasonably high cost-effectiveness
ICI Boilers – Natural Gas	Low NOx Burner and Selective Catalytic Reduction	Disagreed with CoST recommendation of SCR. Used LADCO/OTC recommendation of Low NOx Burners plus Flue Gas Recirculation for Gas-fire ICI boilers with a 60% reduction, except for those sources where a permit or state regulation already required the source to be controlled
ICI Boilers – Residual Oil	Low NOx Burner and Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a state regulation already required the source to be controlled.
Industrial Incinerators	Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SNCR except for those sources where a state regulation already required the source to be controlled.
Iron & Steel Mills – Reheating	Low NOx Burner and Flue Gas Recirculation	Agreed with CoST recommendation except for those sources where a state regulation already required the source to be controlled.
Municipal Waste Combustors	Selective Non-Catalytic Reduction	Agreed with CoST recommendation of SNCR except for those sources where a state regulation already required the source to be controlled.
Nitric Acid Manufacturing	Nonselective Catalytic Reduction	Agreed with CoST recommendation of NSCR except for those sources where a state regulation already required the source to be controlled.
Petroleum Refinery Process Heaters	SCR or Ultra-Low NOx Burner	Nearly all refineries are already controlled due to the OECA global refinery consent decrees, which generally require 40-60% reductions across all boilers/heaters that each company operates. Not possible at present to identify the individual boilers/heaters that actually have been controlled or are scheduled to be control due to confidentiality agreements between EPA and companies.
Utility Boilers – Coal/Wall	Selective Catalytic Reduction	Agreed with CoST recommendation of SCR except for those sources where a state regulation already required the source to be controlled
Utility Boilers – Oil/Gas	Selective Catalytic Reduction	Because of low emissions, assume unreasonably high cost-effectiveness for SCR; use LNB/FGR as reasonable control.

Ammonia – NG-fired Reformers

There are seven sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. For all other sources, we agreed with the CoST control and emission reduction estimate.

Cement Kilns

There are six sources in this category. The CoST control technology was either biosolid injection technology with a 23% reduction in NOx emissions or mid-kiln firing with a 30% reduction. Because of the low baseline emissions for these kilns, we assumed that the kilns were already controlled or have low usage which would result in a very high cost-effectiveness. We determined that no reductions be applied for these sources.

Coal Cleaning – Thermal Dryer

There are 10 sources in this category. The CoST control technology was a low-NOx burner with a 50% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

Commercial/Institutional Incinerators

There are four sources in this category. The CoST control technology was SNCR with a 45% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

External Combustion Boilers, Electric Generation, Coal

There are 14 sources in this category. The CoST control technology was SNCR with a 40% reduction in NOx emissions. It appears that the sources in this category are low usage spreader stokers. Although there may be a concern about the cost-effectiveness for these sources, we agreed with the CoST control and emission reduction estimate.

Fluid Catalytic Cracking Units

There are 21 sources in this category. The CoST control technology was low-NOx burners and flue gas recirculation with a 55% reduction in NOx emissions. All sources in this category are assumed subject to existing control requirements resulting from the OECA global refinery enforcement initiative. Additionally, eight of the sources are located in the Houston nonattainment area and are likely subject to stringent controls. For these reasons, we assumed no further control or emission reductions for the FCCUs.

Gas Turbines

There are 438 sources in this category. The CoST control technology was for low-NOx burners with a 68% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate, except for those sources located in the OTR and Houston ozone nonattainment area, where we assumed that these sources already had RACT controls.

Glass Manufacturing – Container, Flat, Pressed

There are eight sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. Because of the low baseline emissions for these furnaces, we assumed that the furnaces were already controlled and determined that no reductions be applied for these sources.

ICI Boilers – Coal/Stoker

There are 133 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. The LADCO/OTC recommendation was for combustion tuning and SNCR. We agreed with the LADCO/OTC recommendation and assumed a 50% control efficiency.

ICI Boilers – Coal/Wall

There are 11 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. The CoST control technology was low-NOx burners and SCR with a 91% reduction in NOx emissions. The LADCO/OTC recommendation was also for low-NOx burners and SCR. Since the LADCO/OTC recommendation was consistent with the CoST control, we agreed with the CoST control technology and emission reductions.

ICI Boilers – Natural Gas

There are 376 sources in this category. The CoST control technology was low-NOx burners and SCR with a 91% reduction in NOx emissions. The LADCO/OTC recommendation was for low-NOx burners, flue gas recirculation, or low-NOx burners combined with flue gas recirculation. We agreed with the LADCO/OTC recommendation of low-NOx burners combined with flue gas recirculation and assumed a 50% control efficiency, except for those sources located in the OTR and Houston ozone nonattainment area, where we assumed that these sources already had RACT controls.

ICI Boilers – Process Gas

There are 57 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. Most of these sources are located at petroleum refineries and are assumed subject to existing control requirements resulting from the OECA global refinery enforcement initiative, or are located in the Houston nonattainment area and are likely subject to stringent controls. For these reasons, we assumed no further control or emission reductions.

ICI Boilers – Residual Oil

There are 28 sources in this category. The CoST control technology was low-NOx burner and SNCR with a 69.5% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate, except for those sources located in the OTR and Houston ozone nonattainment area, where we assumed that these sources already had RACT controls.

Industrial Incinerators

There are 21 sources in this category. The CoST control technology was SNCR with a 45% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate, except for those sources located in the OTR and Houston ozone nonattainment area, where we assumed that these sources already had RACT controls.

Iron & Steel Mills – Reheating

There are 32 sources in this category. The CoST control technology was low-NOx burners and flue gas recirculation with a 77% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

Municipal Waste Combustors

There are 25 sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. RTI identified the sources are already controlled and no additional reductions were applied for these sources. For the remaining sources, we agreed with the CoST controls and emission reductions.

Nitric Acid Manufacturing

There are 14 sources in this category. The CoST control technology was NSCR with a 98% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

Petroleum Refinery Process Heaters

There are 30 sources in this category. The CoST control technology was SCR with a 90-98% reduction or ultra-low NOx burners with a 30-50% reductions in NOx emissions. Most of these sources are located at petroleum refineries and are assumed subject to existing control requirements resulting from the OECA global refinery enforcement initiative, or are located in the Houston nonattainment area and are likely subject to stringent controls. For these reasons, we assumed no further control or emission reductions.

Utility Boilers – Coal/Wall

There are three sources in this category. The CoST control technology was SCR with a 90% reduction in NOx emissions. We agreed with the CoST control and emission reduction estimate.

Utility Boilers – Oil/Gas

There are 27 sources in this category. The CoST control technology was SCR with a 80% reduction in NOx emissions. The LADCO/OTC recommendation was for low-NOx burners or flue gas recirculation. We agreed with the LADCO/OTC recommendation of low-NOx burners combined with flue gas recirculation and assumed a 60% control efficiency.

Attachment 1 – NOx Emission Reductions by State for Sources in the > 100 Ton per Year Reduction Group

State	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Alabama	24	2,855	2,287	568
Arkansas	6	455	293	162
Delaware	2	206	0	206
Florida	20	2,158	1,370	788
Illinois	21	2,659	1,472	1,187
Indiana	41	5,405	4,510	896
Iowa	10	1,226	999	227
Kansas	7	735	452	283
Kentucky	11	915	838	77
Louisiana	57	7,623	3,622	4,000
Maryland	10	1,933	355	1,578
Michigan	27	2,758	1,768	990
Mississippi	7	1,054	516	538
Missouri	15	1,698	1,562	136
New Jersey	15	417	0	417
New York	30	3,091	281	2,810
Ohio	37	4,098	2,039	2,058
Oklahoma	20	2,949	1,864	1,086
Pennsylvania	52	5,637	2,215	3,422
Tennessee	13	4,741	1,987	2,755
Texas	65	8,860	6,383	2,477
Virginia	28	3,337	3,033	303
West Virginia	9	1,180	793	387
Wisconsin	20	4,092	3,416	676
	547	**70,082**	**42,054**	**28,028**

Attachment 2 – NOx Emission Reductions by Source Group for Sources in the > 100 Ton per Year Reduction Group

Source Group	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Ammonia - NG-Fired Reformers	15	2,427	1,551	875
By-Product Coke Mfg; Oven Underfiring	14	1,199	0	1,199
Cement Kilns	36	3,932	6,586	-2,654
Cement Manufacturing - Dry	20	3,672	2,234	1,438
Cement Manufacturing - Wet	7	1,294	1,120	174
Coal Cleaning-Thrml Dryer; Fluidized Bed	1	50	50	0
Comm./Inst. Incinerators	2	137	0	137
External Combustion Boilers, Solid Waste	6	472	0	472
Fluid Cat Cracking Units; Cracking Unit	6	607	52	556
Fuel Fired Equip; Process Htrs; Pro Gas	2	143	143	0
Glass Manufacturing - Container	34	2,759	678	2,081
Glass Manufacturing – Flat	23	10,241	6,024	4,217
Glass Manufacturing - Pressed	8	684	402	282
ICI Boilers - Coal/Cyclone	8	2,987	1,840	1,147
ICI Boilers - Coal/FBC	3	233	180	53
ICI Boilers - Coal/Stoker	45	4,688	2,938	1,750
ICI Boilers - Coal/Wall	54	12,041	7,996	4,045
ICI Boilers – Gas	10	1,266	910	356
ICI Boilers - Natural Gas	84	7,578	3,452	4,126
ICI Boilers - Process Gas	36	3,868	1,229	2,639
ICI Boilers - Residual Oil	2	199	82	117
Indust. Incinerators	9	586	124	461
In-Proc;Process Gas;Coke Oven/Blast Furn	3	299	0	299

Source Group	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
In-Process; Bituminous Coal; Cement Kiln	2	290	295	-5
Iron & Steel - In-Process Coal Combustion	4	419	0	419
Iron & Steel Mills – Reheating	2	156	156	0
Municipal Waste Combustors	55	1,591	876	715
Nitric Acid Manufacturing	7	687	82	605
Petroleum Refinery Gas-Fired Process Heaters	28	2,025	0	2,025
Taconite Iron Ore - Induration - Coal or Gas	10	829	451	379
Utility Boiler - Coal/Wall	5	555	555	0
Utility Boiler - Oil-Gas/Tangential	2	526	526	0
Utility Boiler - Oil-Gas/Wall	4	1,645	1,524	121
	547	**70,082**	**42,054**	**28,028**

Attachment 3 – NOx Emission Reductions by 3-Digit NAICS Code for Sources in the > 100 Ton per Year Reduction Group

3-Digit NAICS Code	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
211 Oil and Gas Extraction	1	46	30	16
212 Mining (except Oil and Gas)	11	879	500	379
221 Utilities	10	1,186	853	333
311 Food Mfg	12	1,181	815	366
312 Beverage and Tobacco Product Mfg	7	761	761	0
322 Paper Mfg	70	11,616	7,968	3,648
324 Petroleum and Coal Products Mfg	49	3,942	239	3,703
325 Chemical Mfg	132	19,689	10,753	8,937
3272 Glass and Glass Product Mfg	64	13,588	7,047	6,540
3273 Cement and Concrete Product Mfg	64	9,113	10,183	-1,070
3274 Lime & Gypsum Product Mfg	1	75	52	22
331 Primary Metal Mfg	50	4,908	1,837	3,070
333 Machinery Mfg	1	57	35	21
336 Transportation Equipment Mfg	2	148	103	46
424 Merchant Wholesalers, Nondurable Goods	2	160	0	160
531 Real Estate	1	72	0	72
562 Waste Mgmt and Remediation Services	65	2,366	843	1,523
611 Educational Services	5	295	34	261
	547	**70,082**	**42,054**	**28,028**

Attachment 4 – NOx Emission Reductions by 3-Digit NAICS Code for Sources in the > 100 Ton per Year Reduction Group

Recommended Change to CoST Control	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Already Controlled	138	12,973	0	12,973
Already Controlled by Glass CD	12	1,034	0	1,034
Already Controlled By Refinery CD	52	4,300	0	4,300
Control Technically or Economically Infeasible	18	1,618	0	1,618
Fuel Switch Already Occurred	4	2,370	0	2,370
Low NOx Burner	7	629	500	129
Low NOx Burner and Flue Gas Recirculation	88	8,792	6,022	2,769
Low NOx Burner and SCR	44	7,996	7,996	0
Low NOx Burner and SNCR	41	5,895	10,236	-4,341
Non-Selective Catalytic Reduction	1	82	82	0
Oxygen Enriched Air Staging	47	12,077	7,104	4,973
Selective Catalytic Reduction (SCR)	27	6,088	6,088	0
Selective Non-Catalytic Reduction (SNCR)	62	5,109	4,026	1,083
Source Already Shutdown	6	1,120	0	1,120
	547	**70,082**	**42,054**	**28,028**

Attachment 5 – NOx Emission Reductions by State for Sources in the 25 to 100 Ton per Year Reduction Group

State	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Alabama	38	641	517	123
Arkansas	14	277	203	74
Delaware	5	73	58	15
Florida	27	532	399	133
Illinois	91	1,519	845	675
Indiana	44	894	580	314
Iowa	19	422	309	113
Kansas	31	562	421	140
Kentucky	33	619	407	212
Louisiana	101	2,046	1,467	579
Maryland	18	353	209	144
Michigan	67	1,149	844	304
Mississippi	22	366	343	23
Missouri	13	224	179	45
New Jersey	7	72	11	61
New York	41	685	59	625
Ohio	86	1,476	1,075	402
Oklahoma	40	749	669	81
Pennsylvania	79	1,359	423	936
Tennessee	42	742	514	228
Texas	374	6,444	3,311	3,133
Virginia	30	450	350	100
West Virginia	21	421	334	87
Wisconsin	37	697	471	226
	1280	**22,774**	**14,000**	**8,774**

Attachment 6 – NOx Emission Reductions by Source Group for Sources in the 25 to 100 Ton per Year Reduction Group

Source Group	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Ammonia - NG-Fired Reformers2	7	200	155	45
Cement Kilns	4	93	0	93
Cement Manufacturing - Wet	2	60	0	60
Ceramic Clay Mfg; Drying	4	29	0	29
Coal Cleaning-Thrml Dryer; Fluidized Bed	10	188	188	0
Comm./Inst. Incinerators	4	47	47	0
Ext Comb Boilers, Elec Gen, Nat Gas (2)	1	28	28	0
Ext Comb Boilers, Elec Gen, Sub/Bit Coal (3)	14	158	158	0
Fbrglass Mfg; Txtle-Type Fbr; Recup Furn	2	9	9	0
Fluid Cat Cracking Units; Cracking Unit	21	393	0	393
Fuel Fired Equip; Furnaces; Natural Gas	3	18	18	0
Fuel Fired Equip; Process Htrs; Pro Gas	7	86	86	0
Gas Turbines - Natural Gas	438	7,193	5,749	1,444
Glass Manufacturing - Flat	8	190	0	190
ICI Boilers - Coal/FBC	1	35	22	13
ICI Boilers - Coal/Stoker	133	2,502	1,629	873
ICI Boilers - Coal/Wall	11	246	246	0
ICI Boilers - Distillate Oil	4	75	0	75
ICI Boilers - Gas	26	601	0	601
ICI Boilers - Natural Gas	350	6,814	3,705	3,109
ICI Boilers - Oil	2	41	0	41
ICI Boilers - Process Gas	31	609	0	609
ICI Boilers - Residual Oil	28	484	437	47

Source Group	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Indust. Incinerators	21	230	118	113
In-Proc;Process Gas;Coke Oven/Blast Furn	4	33	8	25
Iron & Steel - In-Process Comb - Coal	1	19	0	19
Iron & Steel Mills - Reheating	32	481	481	0
Municipal Waste Combustors	25	472	228	243
Nitric Acid Manufacturing	14	363	289	74
Petroleum Refinery Gas-Fired Process Heaters	30	456	0	456
Solid Waste Disp;Gov;Other Incin;Sludge	1	6	6	0
Space Heaters - Natural Gas	2	17	13	4
Steel Foundries; Heat Treating Furn	7	122	122	0
Surf Coat Oper;Coating Oven Htr;Nat Gas	2	11	0	11
Utility Boiler - Coal/Wall	2	48	48	0
Utility Boiler - Coal/Wall2	1	13	13	0
Utility Boiler - Oil-Gas/Tangential	8	99	62	37
Utility Boiler - Oil-Gas/Wall	19	307	137	170
	1280	**22,774**	**14,000**	**8,774**

Attachment 7 – NOx Emission Reductions by 3-Digit NAICS Code for Sources in the 25 to 100 Ton per Year Reduction Group

3-Digit NAICS Code	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
211 Oil and Gas Extraction	146	2,674	2,573	100
212 Mining (except Oil and Gas)	12	247	227	20
213 Support Activities for Mining	1	20	20	0
221 Utilities	96	1,575	1,035	540
311 Food Manufacturing	46	715	450	266
312 Beverage and Tobacco Products	9	151	91	60
313 Textile Mills	1	24	15	9
314 Textile Product Mills	1	12	7	4
316 Leather and Allied Product Manufacturing	1	10	7	3
321 Wood Product Manufacturing	6	100	56	44
322 Paper Manufacturing	79	1,662	1,028	634
324 Petroleum and Coal Products	115	2,083	527	1,556
325 Chemical Manufacturing	332	6,480	3,218	3,262
326 Plastics and Rubber Products	13	206	142	65
327 Nonmetallic Mineral Product Manufacturing	24	417	32	385
331 Primary Metal Manufacturing	87	1,380	1,094	285
332 Fabricated Metal Product Manufacturing	4	80	46	33
333 Machinery Manufacturing	2	20	14	6
334 Computer and Electronic Products	1	9	9	0
336 Transportation Equipment Manufacturing	13	261	192	69
337 Furniture and Related Products	2	18	18	0
447 Gasoline Stations	1	7	0	7
454 Nonstore Retailers	1	9	0	9

3-Digit NAICS Code	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
482 Rail Transportation	3	37	23	14
486 Pipeline Transportation	156	2,551	2,034	517
488 Support Activities for Transportation	1	18	12	6
531 Real Estate	8	147	0	147
541 Professional Services	6	81	77	4
561 Administrative and Support Services	1	8	0	8
562 Waste Mgmt and Remediation Services	21	376	184	192
611 Educational Services	62	963	617	346
622 Hospitals	7	116	36	80
713 Amusement, Gambling, and Recreation	2	49	45	4
721 Accommodation	2	25	10	15
922 Justice, Public Order, and Safety Activities	4	29	17	12
923 Administration of Human Resources	1	12	8	4
928 National Security and International Affairs	13	201	135	66
	1280	**22,774**	**14,000**	**8,774**

Attachment 8 – NOx Emission Reductions by 3-Digit NAICS Code for Sources in the 25 to 100 Ton per Year Reduction Group

Recommended Change to CoST Control	Number of Sources	NOx emissions reduced from controls in CoST (tons/O3 season) (A)	Recommended NOx emissions reduced from controls in CoST (tons/O3 season) (B)	Size of correction in NOx emission reductions (tons/O3 season) (A - B)
Already Controlled	207	3,380	0	3,380
Already Controlled by Refinery CD	40	704	0	704
Low NOx Burner	362	6,087	6,087	0
Low NOx Burner and Flue Gas Recirculation	361	6,726	4,491	2,235
Low NOx Burner and SCR	11	246	246	0
Low NOx Burner and SNCR	24	437	437	0
Natural Gas Reburn	1	28	28	0
Non-Selective Catalytic Reduction	12	289	289	0
Questions About Feasibility	1	22	0	22
Questions About Feasibility - Cement	6	154	0	154
Questions About Feasibility - Ceramic Clay Mfg	4	29	0	29
Questions about Feasibility - Coating Ovens	2	11	0	11
Questions about Feasibility - Distillate Oil	6	116	0	116
Questions About Feasibility - Glass	7	167	0	167
Questions about Feasibility - Process Gas	50	1,070	0	1,070
Selective Catalytic Reduction	8	216	216	0
Selective Non-Catalytic Reduction	178	3,094	2,207	886
	1280	**22,774**	**14,000**	**8,774**

To: US EPA OAQPS

From: SRA International, Inc.

Subject: Summary of State NOx Regulations for Selected Stationary Sources

Date: September 30, 2014

SRA compiled a summary of state/local NOx emission control regulations pertaining six categories of nonEGUs:

- Cement kilns
- Industrial/Commercial/Institutional (ICI) Boilers – Coal-fired
- ICI Boilers – Gas-fired
- ICI Boilers – Oil-fired
- Gas Turbines
- Internal Combustion (IC) Engines

The analysis included 27 states in the eastern two-thirds of the U.S. For each of these states and source categories, we identified state-specific sub-categories (e.g. fuel type or size threshold), the NOx emission limit or control requirement, averaging time for the emission limit, geographic applicability within the state, testing/monitoring requirements, and rule citation. This information is contained in the attached spreadsheet (Draft State NOx RACT Limits 2014_04_01.xlsx).

Attachment 1 is an overall summary of the relative stringency of the NOx requirements by geographic area and source category. We also prepared a 2-page summary for each of the six categories to concisely compare state NOx emission limits or control requirements. These are shown in Attachments 2 to 7, along with notes highlighting the major differences between the state regulations.

Please let us know should you have questions or comments about any of the data presented in this memorandum.

Attachment 1 – Relative Stringency of NOx Requirements

Source Category	States/Areas with Most Stringent Regulations	States/Areas with Less Stringent Regulations	States with No Regulations or Sources
Cement Kilns[1]	*States*: IL, MD, NY, PA, TX *Areas*: Ellis County, TX	*States*: AL (NOx SIP area), IN, KY, MO, MI, OH, SC, TN, VA, WV	*States*: AR, FL, GA, MS, OK *States with no cement kilns*: CT, DE, LA, MA, NC, NJ, WI
Coal-fired ICI Boilers[2]	*States*: NY *Areas*: Chicago, St. Louis (IL portion), Baton Rouge, Houston-Galveston (coke-fired), Milwaukee,	*States*: FL, GA, IN, MA, MD, MI, PA, TN, VA *Areas*: Chicago, St. Louis (MO portion), Baton Rouge, Charlotte, Cleveland	*States*: AL, AR, KY, MS, OK, SC, TX (except Houston-Galveston) WV *NE States with no coal-fired ICI boilers*: CT, DE, NJ
Gas-fired ICI Boilers	*States*: NJ, NY, PA *Areas*: Chicago, St. Louis (IL portion), Baton Rouge, Beaumont-Port Arthur, Cleveland, Dallas, Houston, Milwaukee	*States*: CT, DE, FL,GA, MA, MD, MI, MO, TN, VA *Areas*: Clark/Floyd Counties, St. Louis (MO portion), Charlotte	*States*: AL, AR, KY, MS, OK, SC, WV
Oil-fired ICI Boilers	*States*: NJ, NY, PA *Areas*: Chicago, St. Louis (IL portion), Baton Rouge, Cleveland, Dallas, Houston, Milwaukee	*States*: CT, DE, FL, GA, MA, MD, MI, TN, VA *Areas*: Clark/Floyd Counties, St. Louis (MO portion), Charlotte	*States*: AL, AR, KY, MS, OK, SC, WV
Gas Turbines	*States*: NJ *Areas*: GA 45-county area, Dallas, Houston, Milwaukee	*States*: CT, DE, FL, LA, MA, MD, NY, PA, TN, VA *Areas*: Chicago, St. Louis (IL portion), St. Louis (MO portion), Charlotte, Cleveland,	*States*: AL, AR, IN, KY, MI, MS, OK, SC, WV
IC Engines > about 500 hp	*States*: MD, NJ, NY *Areas*: Chicago, St. Louis (IL portion), Dallas, Houston	*States*: CT, DE, MA, MI, PA, TN, VA *Areas*: Baton Rouge, St. Louis (MO portion), Charlotte, Cleveland, Milwaukee	*States*: AL, AR, IN, KY, MS, OK, SC, WV

1) Cement kiln emission limits imposed by recent EPA enforcement settlements tend to be more stringent than the emission control requirements in state rules.
2) CT, DE and NJ have no active coal-fired boilers, so the stringency of their regulations for coal-fired ICI boilers is difficult to evaluate

Attachment 2 - Cement Kilns

	NOx Limit (lbs/ton clinker)			
State	**Long Dry**	**Long Wet**	**Pre-heater**	**Pre-calciner**
AL	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			
AR	No Limits	No Limits	No Limits	No Limits
CT	No Cement Kilns in State			
DE	No Cement Kilns in State			
FL	No Limits	No Limits	No Limits	No Limits
GA	No Limits	No Limits	No Limits	No Limits
IL	5.1	5.1	3.8	2.8
IN	6.0	5.1	3.8	2.8
IN (Clark/Floyd)	10.8 (op day)/ 6 (30 day)	No Limits	5.9 (op day)/ 4.4 (30 day)	No Limits
KY	6.6	6.6	6.6	6.6
LA	No Cement Kilns in State			
MA	No Cement Kilns in State			
MD	5.1	6.0	2.8	2.8
MI	6.0	5.1	3.8	2.8
MO	6.0	6.8	4.1	2.7
MS	No Limits	No Limits	No Limits	No Limits
NC	No Cement Kilns in State			
NJ	No Cement Kilns in State			
NY	Case-by-case RACT Determination			
OH	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			
OK	No Limits	No Limits	No Limits	No Limits
PA	3.44*	3.88*	2.36*	2.36*
SC	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			
TN	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			
TX	5.1	4	3.8	2.8
TX (Ellis County)	No Limits	3.4	No Limits	1.7
VA	Case-by-case RACT Determination			
WI	No Cement Kilns in State			
WV	Ozone season: low-NOx burners, mid-kiln system firing, or approved ACT			

ACT = Alternative Control Technology
* Pennsylvania has proposed “RACT 2” presumptive RACT limits

Observations Regarding State NOx Rules for Cement Kilns:

- Geographic Applicability
  - All NOx SIP Call states with cement kilns have NOx rules in place
  - Since only portions of Alabama, Michigan, and Missouri were affected by NOx SIP Call, the NOx rules only apply in the affected counties.
  - States not included in the NOx SIP Call do not have NOx RACT for cement kilns, except for Texas. The Texas NOx requirements only apply in in Bexar, Comal, Ellis, Hays, and McLennan Counties.
- Form of NOx Limitation or Control Requirement
  - A few states express the requirement as "at least one of the following: low-NOx burners, mid-kiln system firing, alternative control techniques or reasonably available control technology approved by the Director and the EPA as achieving at least the same emissions decreases as with low-NOX burners or mid-kiln system firing."
  - A few states specify presumptive emission limits in terms of pounds of NOx per ton of clinker.
  - Three states do not set presumptive emission limits but rather require facilities to submit a case-by-case RACT determination. Pennsylvania has a proposed regulation that will specify presumptive RACT limits; current rules require sources to hold 1 trading allowance per ton of NOx calculated by multiplying tons clinker by the presumptive NOx limit.
- Stringency of NOx Limitation or Control Requirement
  - For states requiring "low-NOX burners, mid-kiln system firing, or ACT", it is generally assumed that this will result in a 30% reduction from uncontrolled levels.
  - For states with numerical emission limits, the limits generally represent a 20 – 40 % reduction from uncontrolled levels, depending on the type of kiln.
  - Texas has very stringent limits for kilns in Ellis County.
  - Pennsylvania has proposed presumptive RACT emission limitations in April 2014 that are more stringent than existing presumptive RACT limits in other states.

Attachment 3 – Coal-fired Boilers

		NOx Limit (lbs/mmBtu)		
State	**Geographic Area**	**Boilers 50-100 mmBtu/hr**	**Boilers 100 - 250 mmBtu/hr**	**Boilers >250 mmBtu/hr**
AL	Statewide	No limits	No limits	No limits
AR	Statewide	No limits	No limits	No limits
CT	Statewide	0.29 to 0.43	0.29 to 0.43	0.29 to 0.43
DE	Statewide	LEA, Low NOx, FGR	0.38 to 0.43	0.38 to 0.43
FL	Broward, Dade, Palm Beach Counties	0.9	0.9	0.9
GA	45 county area	No limits	30 ppmvd @ 3% O2	0.7
IL	Chicago & St Louis areas	Tune-up	0.12 CFB 0.25 Other	0.12 CFB 0.18 Other
IN	Clark and Floyd Counties	No limits	0.4 to 0.5	0.4 to 0.5
KY	Statewide	No limits	No limits	No limits
LA	Baton Rouge 5 counties & Region of Influence	0.2	0.1	0.1
MA	Statewide	0.43	0.33 to 0.45	0.33 to 0.45
MD	Select counties	No limits	0.38 to 1.0	0.38 to 1.0
MI	Fine grid zone	No limits	No limits	0.4
MO	St Louis area	No limits	0.45 to 0.86	0.45 to 0.86
MS	Statewide	No limits	No limits	No limits
NC	Charlotte 6 county area	No limits	0.4 to 0.5	1.8
NJ	Statewide	0.43 to 1.0	0.38 to 1.0	0.38 to 1.0
NY	Statewide	No limits	0.08 to 0.20	0.08 to 0.20
OH	Cleveland 8 county area	0.3	0.3	0.3
OK	Statewide	No limits	No limits	No limits
PA	Statewide	0.45	0.45	0.20 to 0.35
SC	Statewide	No limits	No limits	NOx SIP Call
TN	5 Counties	Source specific RACT	Source specific RACT	Source specific RACT
TX	Houston area	0.057 coke-fired	0.057 coke-fired	0.057 coke-fired
VA	Northern VA	No limits	0.38 to 1.0	0.38 to 1.0
WI	Milwaukee 7 county area	0.10 to 0.25	0.10 to 0.25	0.10 to 0.20
WV	Statewide	No limits	No limits	No limits

Observations Regarding State NOx Rules for Coal-fired Boilers:

- Geographic Applicability
  - States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NOx emission requirements that apply statewide, not just in ozone nonattainment areas.
  - Six states (AL, AR, KY, MS, OK, and WV) do not have regulations limiting NOx emissions.
  - For the remaining states (FL, GA, IL, IN, KY, LA, MI, MO, NC, OH, TN, VA, WI), the NOx emission control requirements only apply in ozone nonattainment areas.
  - Texas only has emission limitations for coke-fired boilers in the Houston-Galveston nonattainment area.
- Size Applicability
  - Most of the states do not have NOx emission requirements for boilers less than 100 mmBtu/hour.
  - 10 states do regulation boilers in the 50-100 mmBtu size range.
- Form of NOx Limitation or Control Requirement
  - Nearly all states express the NOx emission limits in terms of lbs/mmBtu.
  - A few states require either a case-by-case RACT determination or specify specific types of control equipment (e.g., low-NOx burners, flue gas recirculation).
- Stringency of NOx Limitation or Control Requirement
  - Most states specify different emission limits for different types of boilers and firing types (e.g., dry bottom tangential-fired) vs. dry bottom wall-fired)
  - A few states in the Northeast have very few or no coal-fired ICI boilers, so the stringency of the regulations in those states is difficult to evaluate. These states are CT, DE, NJ and MA.
  - For boilers greater than 100 mmBtu/hour, the LADCO/OTC[1] Phase I recommended limits are in the 0.2-0.3 lbs/mmBtu range (depending on boiler/firing configuration). The LADCO/OTC Phase II recommended limits are in the 0.1-0.2 lbs/mmBtu range. Four areas have limits that generally meet the LADCO/OTC recommendations (Chicago, Baton Rouge, New York State, and Milwaukee.
  - Texas has a very stringent limit (0.057 lbs/mmBtu) for coke-fired boilers in the Houston-Galveston area.

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[1] *Evaluation of Control Options for Industrial, Commercial and Institutional (ICI) Boilers Technical Support Document (TSD), March, 2011* prepared by the Lake Michigan Air Directors Consortium (LADCO) and the Ozone Transport Commission (OTC).

Attachment 4 – Gas-fired Boilers

		NOx Limit (lbs/mmBtu)		
State	**Geographic Area**	**Boilers 50-100 mmBtu/hr**	**Boilers 100 - 250 mmBtu/hr**	**Boilers >250 mmBtu/hr**
AL	Statewide	No Limits	No Limits	No Limits
AR	Statewide	No Limits	No Limits	No Limits
CT	Statewide	0.2 to 0.43	0.2 to 0.43	0.2 to 0.43
DE	Statewide	LEA, low NOx, FGR	0.2	0.2
FL	Broward, Dade, Palm Beach Counties	0.2 to 0.5	0.2 to 0.5	0.2 to 0.5
GA	45 county area	30 ppmvd @ 3% O2	30 ppmvd @ 3% O2	0.2
IL	Chicago & St. Louis Areas	Tune-up	0.08	0.08
IN	Clark and Floyd Counties	No Limits	0.2	0.2
KY	Statewide	No Limits	No Limits	No Limits
LA	Baton Rouge 5 counties & Region of Influence	0.1 to 0.2	0.1	0.1
MA	Statewide	0.1	0.2	0.2 to 0.28
MD	Select counties	Tune-up	0.2	0.2
MI	Fine grid zone	No limits	Source specific RACT	0.2
MO	St Louis area	No limits	0.2 to 0.5	0.2 to 0.5
MS	Statewide	No limits	No limits	No Limits
NC	Charlotte 6 county area	0.3	0.3	0.3
NJ	Statewide	0.1 to 0.5	0.1	0.1
NY	Statewide	0.05	0.06	0.08
OH	Cleveland 8 county area	0.1	0.1	0.1
OK	Statewide	No limits	No limits	No limits
PA	Statewide	0.08	0.08	0.08
SC	Statewide	No limits	No limits	No Limits
TN	5 Counties	Source specific RACT	Source specific RACT	Source specific RACT
TX	Dallas and Houston areas	0.03 or 90% reduction	0.03 or 90% reduction	0.03 or 90% reduction
TX	Beaumont area	0.10	0.10	0.10
VA	Northern VA	0.2	0.2	0.2
WI	Milwaukee 7 county area	No limits	0.08	0.08
WV	Statewide	No limits	No limits	No Limits

Observations Regarding State NOx Rules for Gas-fired Boilers:

- Geographic Applicability
  - States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NOx emission requirements that apply statewide, not just in ozone nonattainment areas.
  - Six states (AL, AR, KY, MS, OK, and WV) do not have regulations limiting NOx emissions.
  - For the remaining states (FL, GA, IL, IN, KY, LA, MI, MO, NC, OH, TN, TX,VA, WI), the NOx emission control requirements only apply in ozone nonattainment areas.
- Size Applicability
  - About half of the states have NOx emission requirements for boilers less than 100 mmBtu/hour, ranging from combustion tuning to emission limits as low as 0.05 lbs/mmBtu.
- Form of NOx Limitation or Control Requirement
  - Nearly all states express the NOx emission limits in terms of lbs/mmBtu.
  - A few states require either a case-by-case RACT determination or specify specific types of control equipment (e.g., low-NOx burners, flue gas recirculation).
- Stringency of NOx Limitation or Control Requirement
  - The LADCO/OTC Phase I recommendations are combustion tuning for boilers less than 100 mmBtu/hour, and either 0.1 lbs/mmBtu or 50% reduction for boilers greater than 100 mmBtu/hr.
  - The LADCO/OTC Phase II recommendations are either 0.05-0.1 lbs/mmBtu or 60% reduction.
  - New Jersey and New York have state-wide limits that are consistent with the OTC/LADCO Phase II recommendations. Pennsylvania has proposed state-wide limits that are consistent with the OTC/LADCO Phase II recommendations.
  - Five areas (Chicago, Baton Rouge, Beaumont-Port Arthur, Cleveland, and Milwaukee) have limits that are consistent with the OTC/LADCO Phase II recommendations.
  - Dallas and Houston have the most stringent emission limitations – 0.02 lbs/mmBtu for greater that 100 mmBtu/hr units.

Attachment 5 – Oil-fired Boilers

		NOx Limit (lbs/mmBtu)		
State	**Geographic Area**	**Boilers 50-100 mmBtu/hr**	**Boilers 100 - 250 mmBtu/hr**	**Boilers >250 mmBtu/hr**
AL	Statewide	No limits	No limits	No limits
AR	Statewide	No limits	No limits	No limits
CT	Statewide	0.2 Distillate 0.25-0.43 Resid.	0.2 Distillate 0.25-0.43 Resid.	0.2 Distillate 0.25-0.43 Resid.
DE	Statewide	LEA, Low NOx, FGR	0.38 to 0.43	0.38 to 0.43
GA	45 county area	30 ppmvd	30 ppmvd	0.3
IL	Chicago & St Louis areas	Tune-up	0.1 Distillate 0.15 Resid.	0.1 Distillate 0.15 Resid.
IN	Clark and Floyd Counties	No limits	0.2 Distillate 0.3 Resid.	0.2 Distillate 0.3 Resid.
KY	Statewide	No limits	No limits	NOx SIP Call
LA	Baton Rouge	0.2	0.1	0.1
MA	Statewide	Tune-up	0.3 Distillate 0.4 Resid.	0.25 to 0.28
MD	Select counties	No limits	0.25	0.25
MI	Fine grid zone	No limits	No limits	0.3 Distillate 0.4 Residual
MO	St Louis area	No limits	0.3	0.3
MS	Statewide	No limits	No limits	No limits
NC	Charlotte 6 county area	0.2	0.2	0.2
NJ	Statewide	Tune-up	0.1 Distillate 0.2 Resid.	0.1 Distillate 0.2 Resid.
NY	Statewide	0.08 to 0.2	0.15	0.15 to 0.2
OH	Cleveland 8 county area	0.12 Distillate 0.23 Resid.	0.12 Distillate 0.23 Resid.	0.12 Distillate 0.23 Resid.
OK	Statewide	New only	New only	New only
PA	Statewide	0.12 Distillate 0.20 Resid.	0.12 Distillate 0.20 Resid.	0.12 Distillate 0.20 Resid.
SC	Statewide	No limits	No limits	No limits
TN	5 Counties	Case-by-Case RACT	Case-by-Case RACT	Case-by-Case RACT
TX	Dallas and Houston areas	No limits	~0.01	~0.01
VA	Northern VA	0.25 to 0.43	0.25 to 0.43	0.25 to 0.43
WI	Milwaukee 7 county area	No limits	0.10 Distillate 0.15 Resid.	0.10 Distillate 0.15 Resid.
WV	Statewide	No limits	No limits	No limits

Observations Regarding State NOx Rules for Oil-fired Boilers:

- Geographic Applicability
  - States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NOx emission requirements that apply statewide, not just in ozone nonattainment areas.
  - Six states (AL, AR, MS, OK, SC, and WV) do not have regulations limiting NOx emissions.
  - For the remaining states (FL, GA, IL, IN, KY, LA, MI, MO, NC, OH, TN, TX, VA, WI), the NOx emission control requirements only apply in ozone nonattainment areas.
- Size Applicability
  - About half of the states have NOx emission requirements for boilers less than 100 mmBtu/hour, ranging from combustion tuning to emission limits as low as 0.08 lbs/mmBtu.
- Form of NOx Limitation or Control Requirement
  - Nearly all states express the NOx emission limits in terms of lbs/mmBtu.
  - A few states require either a case-by-case RACT determination or specify specific types of control equipment (e.g., low-NOx burners, flue gas recirculation).
- Stringency of NOx Limitation or Control Requirement
  - The LADCO/OTC Phase I recommendations for distillate oil are combustion tuning for boilers less than 100 mmBtu/hour, and either 0.1 lbs/mmBtu or 50% reduction for boilers greater than 100 mmBtu/hr. The LADCO/OTC Phase II recommendations for distillate oil are either 0.08-0.1 lbs/mmBtu or 60% reduction.
  - Only New Jersey has state-wide limits that are consistent with the OTC/LADCO Phase II recommendations for distillate oil.
  - Three areas (Chicago, Baton Rouge, and Milwaukee) have limits that are consistent with the OTC/LADCO Phase II recommendations for distillate oil.
  - The LADCO/OTC Phase I recommendations for residual oil are combustion tuning for boilers less than 100 mmBtu/hour, and either 0.2 lbs/mmBtu or 60% reduction for boilers greater than 100 mmBtu/hr. The LADCO/OTC Phase II recommendations for residual oil are either 0.2 lbs/mmBtu or 50-70% reduction.
  - New Jersey and New York have state-wide limits that are consistent with the OTC/LADCO Phase II recommendations for residual oil. Pennsylvania has proposed state-wide limits that are consistent with the OTC/LADCO Phase II recommendations for residual oil.
  - Four areas (Chicago, Baton Rouge, Charlotte, and Milwaukee) have limits that are consistent with the OTC/LADCO Phase II recommendations for residual oil
  - Dallas and Houston have the most stringent emission limitations – 0.01 lbs/mmBtu for greater that 100 mmBtu/hr units.

Attachment 6 – Gas Turbines

		NOx Limit (ppmvd @15% O2)			
State	**Geographic Area**	**Simple Cycle >25 MW Gas-fired**	**Simple Cycle >25 MW Oil-fired**	**Combined Cycle > 25 MW Gas-fired**	**Combined Cycle > 25 MW Oil-fired**
AL	Fine grid zone	No limits	No limits	No limits	No limits
AR	Statewide	No limits	No limits	No limits	No limits
CT	Statewide	55	258 (0.9 lb/mmBtu)	55	258 (0.9 lb/mmBtu)
DE	Statewide	42	88	42	88
GA	45 county area	6	6	6	6
IL	Chicago & St Louis areas	42	96	42	96
IN	Statewide	No limits	No limits	No limits	No limits
KY	Statewide	No limits	No limits	No limits	No limits
LA	Baton Rouge 5 counties & Region of Influence	54 (0.2 lb/mmBtu)	86 (0.3 lb/mmBtu)	54 (0.2 lb/mmBtu)	86 (0.3 lb/mmBtu)
MA	Statewide	65	100	42	65
MD	Select counties	42	65	42	65
MI	Fine grid zone	No limits	No limits	No limits	No limits
MO	St Louis area	75	100	75	100
MS	Statewide	No limits	No limits	No limits	No limits
NC	Charlotte 6 county area	75	95	75	95
NJ	Statewide	33 (2.2 lb/MWh)	53 (3.0 lb/MWh)	33 (2.2 lb/MWh)	53 (3.0 lb/MWh)
NY	Statewide	50	100	42	65
OH	Cleveland 8 county area	42	96	42	96
OK	Statewide	No limits	No limits	No limits	No limits
PA	Statewide	42	75	42	75
SC	Statewide	No limits	No limits	No limits	No limits
TN	5 Counties	source specific RACT	source specific RACT	source specific RACT	source specific RACT
TX	Dallas and Houston areas	9 (0.032 lb/mmBtu)	9 (0.032 lb/mmBtu)	9 (0.032 lb/mmBtu)	9 (0.032 lb/mmBtu)
VA	Northern VA	42	65/77	42	65/77
WI	Milwaukee 7 county area	25 to 42	65 to 96	9	9
WV	Statewide	No limits	No limits	No limits	No limits

Appendix B

Observations Regarding State NOx Rules for Gas Turbines:

- Geographic Applicability
  - States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NOx emission requirements that apply statewide, not just in ozone nonattainment areas.
  - Nine states (AL, AR, IN, KY, MI, MS, OK, SC, and WV) do not have regulations limiting NOx emissions.
  - For the remaining states (GA, IL, LA, MO, NC, OH, TN, TX, VA, WI), the NOx emission control requirements only apply in ozone nonattainment areas.
- Other Applicability Criteria
  - States use a variety size thresholds. For example, Ohio’s rules differentiate between units < 3.5 MW and > 3.5 MW. Wisconsin has requirements for three size ranges: 10-25 MW, 25-50 MW, and >50 MW.
  - State limits generally differ by type of fuel – gas or oil. Wisconsin also includes limits for biologically derived fuel.
  - Some states have different limits for simple-cycle and combined-cycle units. Other states have a single limit that applies to both types of units.
- Form of NOx Limitation or Control Requirement
  - States do not specify specific types of control techniques, but rather set a numerical emission limit.
  - Most states express limits in terms of “ppmv at 15% oxygen”. Some states use lbs/mmBtu, and the equivalent limits shown in the table above were calculated using based on Part 75 Eq-F5 and F-factors. New Jersey’s limits are in terms of lbs/MHr.
- Stringency of NOx Limitation or Control Requirement
  - Three areas have very low limits compared to other states/areas: the 45 county area in Georgia, Dallas and Houston-Galveston

Attachment 7 – IC Engines Greater than ~500 hp

		NOx Limit (g/hp-hr)			
State	**Geographic Area**	**Gas-fired, Lean Burn**	**Gas-fired, Rich Burn**	**Diesel**	**Dual Fuel**
AL	Fine grid zone	No limits	No limits	No limits	No limits
AR	Statewide	No limits	No limits	No limits	No limits
CT	Statewide	2.5	2.5	8.0	8.0
DE	Statewide	Technology Stds.	Technology Stds.	Technology Stds.	Technology Stds.
GA	45 county area	?	?	?	?
IL	Chicago & St Louis areas	210 ppmvd @ 15% O2 (2.9 g/hp-hr)	150 ppmvd @ 15% O2 (2.2 g/hp-hr)	660 ppmvd @ 15% O2 (9.1 g/hp-hr)	660 ppmvd @ 15% O2 (9.1 g/hp-hr)
IN	Statewide	No limits	No limits	No limits	No limits
KY	Statewide	No limits	No limits	No limits	No limits
LA	Baton Rouge 5 counties & ROI	4.0	2.0	?	?
MA	Statewide	3.0	1.5	9.0	9.0
MD	Select counties	150 ppmvd @ 15% O2 (1.7 g/hp-hr)	110 ppmvd @ 15% O2 (1.6 g/hp-hr)	175 ppmvd @ 15% O2 (2.0 g/hp-hr)	125 ppmvd @ 15% O2 (1.4 g/hp-hr)
MI	Fine grid zone	3.0	1.5	2.3	1.5
MO	St Louis area	3.0 10.0	2.5 to 9.5	2.5 - 8.5	2.5 - 6.0
MS	Statewide	No limits	No limits	No limits	No limits
NC	Charlotte Area	2.5	2.5	8.0	8.0
NJ	Statewide	2.5	1.5	8.0	8.0
NY	Statewide	1.5	1.5	2.3	2.3
OH	Cleveland	3.0	3.0	3.0	3.0
OK	Statewide	No limits	No limits	No limits	No limits
PA	Statewide	3.0	2.0	8.0	8.0
SC	Statewide	No limits	No limits	No limits	No limits
TN	5 Counties	Source specific RACT	Source specific RACT	Source specific RACT	Source specific RACT
TX	Dallas and Houston area	0.5	0.5	2.8 to 6.9	0.5
VA	Northern VA	Source specific RACT	Source specific RACT	Source specific RACT	Source specific RACT
WI	Milwaukee 7 county area	3.0	3.0	3.0	3.0
WV	Statewide	No limits	No limits	No limits	No limits

Observations Regarding State NOx Rules for IC Engines:

- Geographic Applicability
  - States in the OTR (CT, DE, MA, MD, NJ, NY, and PA) have NOx emission requirements that apply statewide, not just in ozone nonattainment areas.
  - Eight states (AL, AR, IN, KY, MS, OK, SC, and WV) do not have regulations limiting NOx emissions.
  - For the remaining states (GA, IL, LA, MI, MO, NC, OH, TN, TX, VA, WI), the NOx emission control requirements only apply in ozone nonattainment areas.
- Other Applicability Criteria
  - States use a variety size thresholds. For example, Louisiana's rules have separate limits for IC engines that are 150-300 hp, >300 hp, and >1500 hp. New York uses > 200 hp and > 400 hp. Delaware uses > 450 hp, while North Carolina uses > 650 hp.
  - State limits generally differ by type of fuel – gas, oil, dual-fuel or landfill/digester gas.
  - A few states have different limits lean-burn and rich-burn engines. Other states have a single limit that applies to both types of units.
- Form of NOx Limitation or Control Requirement
  - Most states express limits in terms of "gram per brake horsepower hour".
  - Some states use "ppmvd @ 15% O2", and the equivalent limits shown in the table above were calculated using conversion factors from ppmv @ 15% O2 to g/hp-hr from EPA ACT, July 1993 EPA453-R-93-032.
  - Delaware specifies control technology standards rather than numerical emission limits.
- Stringency of NOx Limitation or Control Requirement
  - Maryland, New Jersey, New York and the Dallas/Houston areas of Texas have limits that are more stringent than other states/areas.

STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF:

PROPOSED NEW REGULATION
20.2.50 Oil and Gas Sector — Ozone Precursor Pollutants **No. EIB 21-27(R)**

PRE-FILED TECHNICAL TESTIMONY OF MR. JOHN DUTTON,
A WITNESS ON BEHALF OF THE GAS COMPRESSOR ASSOCIATION

I. Introduction to My Testimony

My name is John Dutton. I am testifying as a technical witness on behalf of The Gas Compressor Association (The GCA) in this proceeding. My testimony supports The GCA's proposed amendments to the New Mexico Environment Department's (Department) proposed regulation set out as 20.2.50.113.B(2) NMAC and 20.2.50.113.B(3) NMAC in the Department's proposed rule 20.2.50 NMAC (Proposed Rule). The GCA's proposed amendments to the parts of the Proposed Rule that are the subject of my testimony, the emission standards for engines, are set forth in redline in GCA Exhibit 1.

This testimony begins with an overview of my credentials. I will then discuss the Department's proposed engine emissions standards, as set forth in the Proposed Rule at 20.2.50.113.B(2) NMAC and 20.2.50.113.B(3) NMAC and The GCA's proposed amendments thereto. As discussed in this testimony, The GCA's proposed changes to these subsections seek to preserve the Department's central goal of reducing NOx emissions while better accounting for practical realities involving the availability and use of lean-burn engine designs, and avoiding prohibitive cost burdens that would bear little or no relationship to the goal of promoting emission reductions.

I will specifically offer testimony regarding the proposed NOx emissions limits for lean-burn engines over 1000 horsepower in 20.2.50.113.B(2), Table 1 NMAC and the proposed horsepower break in 20.2.50.113.B(3), Table 2 NMAC, and offer testimony to support why four-stroke lean-burn engines in Table 2 that are required to meet 0.3 g/bhp-hr NOx should start at 1875 horsepower rather than 1000 horsepower, as currently proposed in the rule, to accurately reflect the capabilities of lean-burn engines. I will further explain in my testimony engine driver selection as it relates to natural gas compressor packages and the importance of having viable options from more than one manufacturer and that some post combustion controls, *i.e.,* selective catalytic reduction, for lean-burn engines are not economically viable. I will go on to explain why retrofitting existing engines can be cost prohibitive. Finally, I will explain why the NOx requirements for lean-burn engines as set forth in the Proposed Rule at 20.2.50.113.B(2), Table 1 NMAC and 20.2.50.113.B(3), Table 2 NMAC should be revised, and why the Department's proposed inclusion of "Construction" as defined in the rule and "Installation" as a criteria in Table 1 and Table 2 is not appropriate. The applicability of the emission standards should be based on an engine's date of manufacture or reconstruction.

II. Statement of My Qualifications and Relevant Experience.

My resume is attached as GCA Exhibit 13. I received my Bachelor of Science degree in mechanical engineering from the University of Oklahoma in 1991. Since 1991, I have worked in the natural gas compression and midstream pipeline segments. I am a Professional Engineer in the State of Oklahoma.

I began my career as an engineer with a midstream pipeline company in Oklahoma. During that time, I designed pipeline segments and facilities, including the selection of natural gas compressor packages. I also performed reserve estimates and calculated discounted cash flow economics. In 1998, I joined J-W Operating Company (now J-W Energy Company). For the last twenty-three years, I have served in various capacities for the J-W Energy family of companies, working in financial analysis, operations and executive roles in our midstream gathering and compression services businesses. I currently work as President of J-W Power Company, a subsidiary of J-W Energy Company. My current job responsibilities include determining and implementing short and long-term strategic plans to create value for all stakeholders. I am responsible for all aspects of leading and managing the company including safety, daily operations, sales, financial performance, strategic planning, regulatory compliance, economic evaluation and investment of capital.

J-W Power Company is an industry leader in the natural gas compressor business. J-W Power Company has been involved in natural gas compression since 1966, and currently operates one of the largest privately-owned compression leasing fleets in the United States. J-W and other compression services providers rely heavily on the types of engines that are regulated under the Proposed Rule. Through my many years at J-W Power Company, I have become intimately familiar with these engines, their specifications, and how they perform, and how they are regulated. Throughout my career, I have dealt with the engines regulated by the Proposed Rule on a daily basis, both as a consumer who purchases these engines from the manufacturers, and as part of a company that manufactures natural gas compression packages that incorporate those engines and as a compression services provider that must rely on those engines to provide reliable and compliant compression services for our customers.

The GCA is an association whose members include the owners and operators of the engine-driven natural gas compressors that are utilized to provide compression services to oil and gas producers and to midstream companies in the oil and gas industry in New Mexico and throughout the United States. The GCA members serve a vital function in the New Mexico oil and gas industry, and The GCA members' operations in New Mexico are affected by many parts of the Proposed Rule. J-W Power Company is a member of The GCA. In The GCA, I have served as chairman of the environmental committee, as a member of the board of directors, and, in 2017, as chairman of the board.

III. The Proposed Rule's Emission Standards for Existing and New Engines in 20.2.50.113.B(2)&(3) NMAC

(i) The Proposed Emissions Standards for New Engines Set Forth in 20.2.50.113.B(3) NMAC Limit Engine Driver Selection.

There are two major engine manufacturers with established natural gas fired reciprocating engines in the natural gas compression industry for engines with over 1000 horsepower. Those manufacturers are Waukesha, whose primary offerings utilize rich-burn technology, and Caterpillar, whose offerings utilize lean-burn technology.

Lean-burn technology achieves low emissions levels by controlling the actual combustion process, but has limits to the level it can achieve based on physical size constraints which primarily affects the ability to use pre-combustion chamber technology. *See* Pre-filed Technical Testimony of Vic Sheldon, GCA Exhibit 9. The newest larger bore engines have more capability and can achieve the Department's proposed 0.3 g/bhp-hr NOx level as set forth in 20.2.50.113.B(3) NMAC, but these larger bore engines are 1875 horsepower and larger and are 2015 and newer vintage. The Department's proposal in 20.2.50.113.B(3), Table 2 NMAC requiring new four-stroke lean-burn engines over 1000 horsepower to meet 0.3 g/bhp-hr NOx is not consistent with the available technology and would effectively eliminate the use of four-stroke lean-burn engines between 1000 and 1875 horsepower.

Rich-burn technology utilizes precise air-fuel ratio control and must use post combustion treatment via non-selective catalytic reduction (NSCR). The rich-burn technology is scalable down to smaller engines with a reasonable cost per ton of NOx reduction, and with the available NSCR control technology can achieve the emission standards in 20.2.50.113.B(2), Table 1 NMAC or 20.2.50.113.B(3), Table 2 NMAC. As such, the remainder of my testimony applies only to four-stroke lean-burn spark ignited engines.

Both rich-burn and lean-burn technologies have certain advantages, and neither technology should be excluded as part of this rulemaking process. Historically, competition within the space has driven continuous improvement; including technology utilized to reduce emissions and continued support by the manufacturers. The choice of an engine manufacturer and associated combustion technology is a complicated decision and is dependent upon many variables. First, the engine must be matched to the driven equipment by power and speed ratings. Site conditions such as elevation and fuel quality can affect the performance of the engine and result in power being de-rated under some circumstances. Transportation and installation constraints are also part of site conditions, and can limit the ability to use larger engines. Second, other factors such as expertise of operator, supply chain quality, manufacturer support and life cycle costs must be considered. The economic life of a reciprocating natural gas compressor stationary engine this size is 20 to 50 years with scheduled overhauls throughout the life.

The proposed NOx emission standard for new engines would significantly interfere with the market by effectively eliminating the use of an entire class of reliable, efficient, high-performing engines that are important to the compression services providers that operate in New Mexico. The Department should revise the NOx standard in the final rule to avoid forcing a choice on market participants and banning a group of engines that meet and exceed federal standards and operate in compliance with emissions standards across the rest of the country.

(ii) It is Not Economically Viable to Use Post-Combustion Controls to Comply with the Department's Proposed New Engine Emission Standards Set Forth in 20.2.50.113.B(3) NMAC.

The proposed emission standards in Table 2 included in the Proposed Rule at 20.2.50.113.B(3) NMAC would effectively eliminate the lean-burn option from 1000 bhp to 1875 bhp, because the technology to achieve 0.3 g/bhp-hr NOx does not exist without post-combustion controls. The Proposed Rule does provide optional limits for NOx emissions "with control" (i.e., using add-on emission controls). For lean-burn engines, the method for post-combustion control is Selective Catalytic Reduction (SCR). SCR is not operationally or economically viable for the lean-burn engines regulated by the Proposed Rule. The technical spreadsheet supplied by the Department "ICE-Reductions-andCosts-NO2-6-4-21.xls" (NMED Calculations), GCA Exhibit 14, estimates the cost for SCR are approximately $10,206 to $13,555 per ton of NOx on a lean-burn engine of this size range, compared to $101 to $112 per ton of NOx for rich-burn engines with NSCR. The relevant provisions of this table are set forth below in Image 1. These cost estimates are suspect, as very little actual cost data is available because of the impracticable nature of SCR in engines of this size range and the estimates are founded on application of SCR to compression-ignition (diesel) engines. Even if those lean-burn engine cost figures are assumed to be accurate, however, at well over $10,000 per ton of NOx reduction, they represent an unreasonable cost of control.

Image 1

Cost of Control Per Ton Pollutant Reduced for Spark Ignited Internal Combustion Engines. From Bradley Nelson, Alpha-Gamma Technologies, Inc., to Jaime Pagán, EPA/OAQPS/ESD/Combustion Group. May 11, 2006. EPA-HQ-OAR-2005-0030-0060. p. 3.

Horse Power	SCR for Lean Burn Engines ($/ton)	NSCR for Rich Burn Engines ($/ton)
750-1200	$ 10,206	$ 109
1200-2000	$ 13,555	$ 101
>2000	$ 15,813	$ 112

(iii) The Proposed Rule's Emission Standard for Existing Lean-Burn Engines is Based on Faulty Assumptions.

Based on the Department's conclusions as set forth in another excerpt of the NMED Calculation Spreadsheet, Image 2 below, it appears that the Department is assuming that Low Emission Combustion (LEC) technology can be applied to existing four-stroke lean-burn engines that are less than 3,000 horsepower (as a retrofit) to reduce the NOx emissions to the rule limits proposed in 20.2.50.113(B)(2) NMAC.

Image 2

See the "%Reductions" tab for the reduction assigned to each engine based on age, horsepower, controls, and current regulation.

Engine Type	Control Type	Cost Factor Reference
2SLB < 3,000 hp	LEC for NOX	CSAPR TSD and the EPA's Control Strategy Tool (CoST)
4SLB < 3,000 hp	LEC for NOX	CSAPR TSD and the EPA's Control Strategy Tool (CoST)
2SLB > 3,000 hp	LEC for NOX	INGAA
4SLB > 3,000 hp	LEC for NOX	INGAA
Rich Burn	AFR/NSCR for NOX & VOC	2010 NESHAP for RICE
Compression Ignition	SCR for NOX	
	For costs, if engines type is unknown from the SCC, we assumed it was 4SLB for engines >= 1,000 HP.	

The reference for the LEC cost equation in the NMED Calculations is approximately twenty years old (circa 2001). At that time, it was assumed that LEC could be applied and achieve an 80% NOx reduction from a starting point of 9.0 g/bhp-hr. The reference cited by the NMED Calculations, Technical Support Documentation for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS Docket ID No. EPA-HQ-OAR-2015-0500, GAC Exhibit 11, states "*LEC* *are described as retrofit kits that allow engines to operate on extremely lean fuel mixtures to minimize NOx emissions. The LEC retrofit may include: (1) redesign of cylinder head and pistons to improve mixing (on smaller engines), (2) Precombustion chamber (on larger engines), lower cost, simple versions, (3) Turbocharger, (4) High energy ignition system, (5) Aftercooler, and (6) Air-to-fuel ratio controller. (CSAPR TSD, p. 5-3).*" GAC Exhibit 11 at p. 5-3. Although the cost recovery factor was updated to current assumptions and the capital cost has been escalated to represent current levels, the underlying assumption that the LEC retrofit technology can still be applied to these engines is false. The vast majority of high speed four-stroke lean-burn engines in the natural gas compression space have been utilizing the LEC technology for years and most are capable of 2.0 g/bhp-hr, which approximates the 80% reduction from the original 2001 assumption of 9.0 g/bhp-hr.

The above-referenced EPA document that the Department relies upon for its description of LEC, GCA Exhibit 11, recognizes the limitation of using pre-combustion chambers on smaller engines. The use of pre-combustion chambers is significant, because it enables the engine to use an extremely lean mixture and thus achieve the lowest possible NOx emissions level. The Pre-filed Technical Testimony of Vic Sheldon, CGA Exhibit 9, details the limitation of using pre-combustion chambers on smaller engines as applied to Caterpillar G3500J LE and G3600 A4 engine families. The engine family distinction is important when determining the threshold to achieve 0.3 g/bhp-hr NOx emissions for new four-stroke lean-burn engines for 20.2.50.B(2), Table 2 NMAC.

As shown in Image 3 below, another excerpt from the NMED Calculation Spreadsheet, GCA Exhibit 14, the Department's calculations appear to use AP-42 Emissions factors of 0.98

g/bhp-hr for uncontrolled emissions factors which further shows that LEC has already been applied.

Image 3

AP-42 Emission Factors for NOx Emissions for Natural Gas Fired Reciprocating Engines <90% of Load:			These were the EF's used to e
Engine Type:	lb/MMBtu	g/hp-hr	Reference (from AP-42, July 2000 edition, section 3.2 Natural Gas-fired Reciprocating Engines):
2 Stroke Lean Burn	1.94	2.24	TABLE 3.2-1 UNCONTROLLED EMISSION FACTORS FOR 2-STROKE LEAN-BURN ENGINES (SCC 2-02-002-52)
4 Stroke Lean Burn	0.847	0.98	Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES (SCC 2-02-002-54)
4 Stroke Rich Burn	2.27	2.62	Table 3.2-3. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE RICH-BURN ENGINES (SCC 2-02-002-53)

It appears that the Department is assuming that 0.5 g/bhp-hr NOx on existing engines can be achieved through the further application of LEC ("further" because the starting point for this calculation already assumes that LEC is employed). The assumed reduction of NOx from 0.98 g/bhp-hr to 0.5 g/bhp-hr would thus result in a 49% reduction as provided in the Reduction Matrix from the NMED Calculations as shown in Image 4 below.

Image 4

Reduction matrix			
NG	Controlled by SCR / NSCR /		0%
NG	Uncontrolled	LeanBurn 4-stroke >1000	49%
NG	Uncontrolled	LeanBurn 2-stroke >1000	78%
NG	Uncontrolled	RichBurn >1000	81%
NG	NSPS JJJJ Before 2011	LeanBurn 4-stroke >1000	49%
NG	NSPS JJJJ Before 2011	LeanBurn 2-stroke >1000	75%
NG	NSPS JJJJ Before 2011	RichBurn >1000	75%
NG	NSPS JJJJ 2011 +	LeanBurn 4-stroke >1000	49%
NG	NSPS JJJJ 2011 +	LeanBurn 2-stroke >1000	50%
NG	NSPS JJJJ 2011 +	RichBurn >1000	50%
Diesel	Controlled	>1000 hp	55%

The ability to apply LEC technology again to achieve further reductions in NOx from existing lean-burn engines greater than 1000 bhp varies drastically based on the make and model of the engine. The Department should not base the engine NOx standards on an assumption that LEC can be broadly applied again, or that it would reduce NOx emissions by 49%.

Retrofit control technology on an existing lean-burn engine in a compression package or replacement of an engine with a different engine may not be technically feasible or physically possible. A natural gas compressor package is designed and built around a specific engine. The engine pedestal has a specific size and height to precisely position the engine centerline with the compressor and to accommodate the specific engine mount locations which are unique to each engine model. In addition, the overall package size (width and length) are built to accommodate a specific combination of engine and compressor combination. The cooler for the package is also designed around the heat rejection characteristics of the engine. Converting an engine to a different combustion design usually results in changes to the cooler and associated piping which adds significant cost.

In addition to heat rejection and cooler design factors, installing a different engine type is likely cost prohibitive especially if the replacement engine is physically larger. In some cases, the cost to retrofit exceeds the cost of a new engine. For example, a conversion of a G3606 A3 (1775 horsepower with 0.5 g/bhp-hr NOx) to a G3606 A4 (1875 horsepower with 0.3 g/bhp-hr NOx) along with the necessary package modifications is approximately 120% of the cost of a new engine. The high cost is driven by the significant differences in engine components including the turbocharger, aftercooler, pistons, rods, camshafts, inlet air connections and exhaust outlet.

(iv) Consequences of the Proposed 20.2.50.113.B(2) NMAC NOx Emission Standards for Existing Engines.

Because SCR is not practicable and LEC is already incorporated in the vast majority of the high speed lean-burn engine population, the result of the Department's proposed NOx emission standards for engines at 20.2.50.113.B(2) NMAC would be wide-spread elimination and replacement of *existing* lean-burn engines above 1000 bhp. Table 1 and the timeline set forth in proposed 20.2.50.113.B(2) NMAC effectively mandates replacement of a large number of "existing" lean-burn engines that employ LEC to reduce NOx emissions, but nonetheless are not capable of achieving the NOx limits as-proposed. Table 1 of 20.2.50.113.B(2) NMAC should be amended to reflect NOx standards for existing engines that are consistent with the application of LEC technology as shown below:

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

Engine Type	Rated bhp	NOx	CO	NMNEHC (as propane)
Lean-burn	> 1,000	~~0.50~~2.0 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

(v) Consequences of the Proposed 20.2.50.113.B(3) NMAC NOx Emission Standards for New Engines.

If the Proposed Rule is adopted in its current form, operators who require engines from 1000 to 1875 bhp would not even be able to purchase a *new* lean-burn engine that complies with the applicable NOx emission standard. Instead, they would have to purchase new rich-burn engines or utilize multiple smaller engines on one location to achieve the combined horsepower needs. Alternatively, a larger-than-necessary engine that is capable of achieving the required emissions levels could be used and operated at partial load. However, this would result in unnecessary and wasteful capital investment and increased operating expenses. Operating an engine at partial load also causes challenges with emissions compliance testing and creates permitting issues because potential to emit would still be based on nameplate power. Combining gas streams or nodes to enable the additional horsepower to be utilized for the sole reason of utilizing larger engines would rarely be economical. By eliminating a whole class of engines, the proposed NOx standard would effectively shrink the market for consumers of new engines for use in New Mexico. Moreover, it would create a host of unnecessary operational challenges for compressor service providers seeking a work-around, particularly in the many situations where a lean-burn engine between 1000 and 1875 horsepower is the appropriate size of engine. Therefore, 20.2.50.113.B(3), Table 2 NMAC should be amended as follows:

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

Engine Type	Rated bhp	NOx	CO	NMNEHC (as propane)
Lean-burn	>500 - <~~1000~~1,875	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Lean-burn	≥ ~~1000~~1,875	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

(vi) Applicability of the Engine Emission Standards Should Be Based Only on Date of Manufacture or Reconstruction.

As proposed, 20.2.50.113.B(2), Table 1 NMAC and 2.2.50.113.B(3), Table 2 NMAC currently determine applicability based on whether an engine is "constructed, reconstructed, or installed" (emphasis added) either before (Table 1) or after (Table 2) the effective date of the rule. "Construction" is defined in the Proposed Rule at 20.2.50.7.J NMAC as "…fabrication, erection, installation or relocation of a stationary source, including but not limited to temporary installations and portable stationary sources." This definition and how the Proposed Rule determines new or existing standard applicability is not consistent with how the EPA determines applicability for spark-ignition engines. EPA's standards for spark-ignition engines in 40 CFR Part 60, Subpart JJJJ bases applicability on the "date of manufacture" – which is when an engine is originally produced, or when it is reconstructed. See 40 CFR § 60.4230 (basing applicability on manufacture date) and 40 CFR § 60.4248 (defining "date of manufacture").

The language in the Proposed Rule would consider an engine to be "new" (and therefore subject to the new engine emission standards in Table 2 of 20.2.50.113.B(3) NMAC instead of the existing engine emission standards in Table 1 of 20.2.50.113.B(2) NMAC) if it is relocated. As discussed in the Pre-filed Technical Testimony of Vic Sheldon, GCA Exhibit 9, the technology to achieve 0.3 g/bhp-hr NOx level for lean-burn engines is built into the engine (and the remainder of the package as well, as described in my testimony above) and it can be cost prohibitive if not technically infeasible to retrofit older engines with technology that was not part of the original design. An engine should not be considered "new" just because the engine is moved and "installed" at a new location. Relocation of compressor packages is common, and nothing about the relocation should provide a basis for converting the engine in that package from an existing engine into a new engine subject to significantly more-stringent emission standards.

The GCA has proposed to change the applicability triggers for new and existing engine emission standards under the Proposed Rule to make them consistent with the applicable federal standards and to avoid the arbitrary and unreasonable new-source trigger based on "installation" at a new location. "Installed" should not be a criteria for determining if an engine is "new" as opposed to "existing." For these reasons, the amendments to 20.2.50.113.B(2), Table 1 NMAC and 20.2.50.113.B(3), Table 2 NMAC as set forth above, changing "Constructed" to "Manufactured" and removing the word "Installed," is appropriate.

Determining the applicability of emission standards for engines only makes sense if based on the date of manufacture or reconstruction. The GCA's recommended horsepower levels and NOx limits in 20.2.50.113.B(2), Table 1 NMAC and 20.2.50.113.B(3), Table 2 NMAC are predicated on and dependent upon these changes to how applicability of the emission standards is determined. If the Department does not change the engine applicability to remove the concepts of "constructed" and "installed" as suggested, then the Department should provide emission limits specific to individual manufacturers, models and vintage, because these factors affect an engine's ability to achieve a given NOx limit.

IV. Conclusion

The Department's proposed emissions standards for natural gas-fired spark-ignition four-stroke lean-burn engines as set forth in 20.2.50.113.B(2), Table 1 NMAC and 20.2.50.113.B(3), Table 2 NMAC of the Proposed Rule should be amended as set forth in GCA Exhibit 1 to accurately reflect the capabilities of four-stroke lean-burn engines of this size. The GCA's proposals are dependent upon also changing "Constructed" to "Manufactured" and removing "Installed" from the description of the tables.

This concludes my direct technical testimony in this matter.

JOHN DUTTON, P.E.

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jdutton@jwenergy.com

Mechanical Engineer with 30 years of Experience in the natural gas compression and midstream pipeline segments. For the last 23 years, I have served in various capacities for the J-W Energy Family of companies, working in financial analysis, operations and executive roles.

EXPERIENCE

DECEMBER 2017 – PRESENT

PRESIDENT, J-W POWER COMPANY

Determine and implement short and long term strategic plan to create value for all stakeholders. Responsible for all aspects of leading and managing the company including safety, daily operations, sales, financial performance, strategic planning, regulatory compliance, economic evaluation and investment of capital.

2008 – 2017

VICE PRESIDENT OF OPERATIONS, MANAGER OF OPERATIONS, J-W POWER COMPANY

Directly Supervised Technical Service Department which was responsible for training and troubleshooting natural gas compressor packages. Provided leadership as a partner with commercial and field operations managers to develop strategies and process related to safety, regulatory compliance, economic guidance and operational performance. Evaluated and oversaw acquisition opportunities including the acquisition of Enerven in December 2012.

2002 – 2004

MANAGER OF OPERATIONS, J-W GATHERING COMPANY

Responsible for engineering and field operations of 8 midstream gathering and processing systems assets with a throughput of 100 MMCFD located in Texas, Wyoming and Colorado. Oversaw regulatory compliance including air permitting and DOT requirements.

1998 – 2002

FINANCIAL ANALYST, J-W OPERATING COMPANY

Performed financial analysis and discounted cash flow calculations in support of acquisitions and divestitures. Completed 14 acquisitions over a 4 year period. Assisted in due diligence and initial assimilation of acquired companies.

1991 – 1998

ENGINEER, DELHI GAS PIPELINE

Operations and supply engineer for a midstream pipeline company in Western Oklahoma. Designed pipelines segments and related components. Performed compressor sizing calculations and optimization. Assisted with safety and regulatory compliance. Estimated well production and reserves and evaluate economic viability of projects using discounted cash flow modeling.

EDUCATION

DECEMBER 1991

B.S. MECHANICAL ENGINEERING, UNIVERSITY OF OKLAHOMA

National Merit Scholar

OTHER

- Served 4 years as chairman of GCA Environmental Committee
- Eagle Scout
- Instrument Rated private pilot with multi-engine rating.
- Served 1 year as Vice President and 5 years as President of the Dallas Area Pontiac Association
- Professional Engineer in the State of Oklahoma

STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF:

PROPOSED NEW REGULATION **No. EIB 21-27 (R)**
20.2.50 Oil and Gas Sector — Ozone Precursor Pollutants

PRE-FILED TECHNICAL TESTIMONY OF MR. MARK COPELAND, A WITNESS ON BEHALF OF THE GAS COMPRESSOR ASSOCIATION

I. Introduction to My Testimony

My name is Mark Copeland. I am testifying as an expert witness with respect to certain aspects of the New Mexico Environment Department's ("NMED") proposed regulation, 20.2.50 NMAC ("Proposed Rule"), as summarized in The Gas Compressor Association's ("The GCA") Notice of Intent to Present Technical Testimony filed in this proceeding. This testimony begins with an overview of my credentials. I will then go on to discuss certain provisions of the Proposed Rule that The GCA respectfully requests be reconsidered by the NMED and/or modified by the Environmental Improvement Board ("EIB").

I fully understand the importance of sound and appropriate processes and procedures geared toward minimizing to the extent feasible the release of ozone precursor pollutants. However, I also know from my multiple decades in the natural gas compression industry—including my responsibilities associated with my employers' compliance with federal and state air emission standards—that certain aspects of the proposed regulations are simply too onerous to be practically implemented and, even if future implementation is viable at some point, will not achieve any recognizable reduction in those emissions. I believe that The GCA's suggested changes to the Proposed Rule will retain the environmental and air quality benefits of the rule while eliminating limited aspects of the Proposed Rule that appear unduly burdensome with no corresponding benefit to the environment.

II. Statement of My Qualifications and Relevant Experience

My resume is attached as GCA Exhibit 16. I received a Bachelor of Science degree in mechanical engineering from Southern Methodist University in 1983. I have over thirty-two years of experience working in the energy industry, in particular, the natural gas contract compression space, a niche that sells, services and owns and operates equipment that aids our customers' production of oil and gas (e.g., gas lift) and makes the post-production transportation of their natural gas to market possible by increasing the pressure of that gas as it moves from wellhead to market. Outsourced natural gas compression services represent approximately 30% of the total natural gas compression space, with the remaining estimated 70% being provided by our customers utilizing their owned natural gas compression equipment. Natural gas compression is a must-run function and, as a result, we operate and maintain our compression equipment so that it is as capable as possible of operating at optimal efficiently, with material longevity (measured in decades) and in compliance with laws 24 hours a day, 7 days a week and 365 days a year.

My career has been spent with three companies, all involved in the natural gas compression industry, two of which are members of The GCA. Over twenty-one years of my career were spent with my current employer, Archrock, including three years as a Regional Manager in New Mexico. For the past fifteen years, my focus has included:

- overseeing company-wide development of operations and maintenance processes and improvements to, among other things, ensure efficient operations; maintain our must-run availability for our customers; and ensure compliance with applicable law, including state and federal emission regulations;
- overseeing the operation of our Operations Support Center through which our

customers can reach us regarding operational issues 24/7/365; and

- monitoring our compliance with relevant emissions regulations, including NESHAP Subpart ZZZZ and NSPS Subpart OOOO. As an industry and a group of organizations, we have worked closely with regulatory authorities—notably including the Environmental Protection Agency ("EPA") during the NESHAP Subpart ZZZZ rulemaking in 2013 and 2014—to ensure our mutual goal of minimizing emissions to the extent practicable based on proven technology while satisfying the market need and demand for clean-burning natural gas by helping transport it to market.

III. Technical Issues Posed by Specific Provisions of Proposed Rule 20.2.50 NMAC

A. The Proposed Rule's Engine Maintenance Requirements: Requirement to Follow Manufacturer's Recommended Maintenance Schedule

i. Proposed Rule 20.2.50.113.C(1) NMAC

Proposed Rule 20.2.50.113.C(1) NMAC calls for the maintenance and repair of spark-ignition engines (such as those contained in our natural gas compression packages), among others, and requires the owner or operator to "meet the minimum manufacturer recommended maintenance schedule." As set forth below, there are a number of reasons that render this constraint on the maintenance flexibility of experts in the operation of these engines in a contract compression services application impractical, overly burdensome, unnecessarily expensive and counterproductive.

ii. Manufacturers' Maintenance Recommendations are Generic Attempts to Make One-Size Fit All, And Frequently They Require Prudent Adjustments to Fit Various Conditions

Whereas manufacturers' maintenance recommendations are generally the same across engine uses without taking into account specific operating and fuel conditions—each of which has a material impact on the most efficient and successful means of operating and maintaining the subject compression package—contract compression service providers and compression package operators tailor their maintenance plans to serve a wide variety of customer sites and are specifically tailored for the provision of compression services. Impactful operating variables include, without limitation and in no particular order:

- Altitude
- Ambient Temperature
- Weather Conditions
- Fuel Gas Conditions (e.g., wet versus dry, H2S content, CO2 content)
- Process Gas Conditions (similar variables as fuel gas)

Manufacturers' recommended maintenance practices cannot and do not aptly address the entire spectrum of engine uses, gas conditions and operating conditions. Some uses are on-road whereas ours is off-road. Some uses are periodic and intermittent, with frequent wear-increasing idling, starting and stopping, whereas ours use ideally involves continuous, consistent uptime.

Engine operators in industrial applications—like contract compression services—have well-established operations and maintenance programs that include "condition-based" maintenance, which allows for experiential maintenance decisions based on the aforementioned operating conditions and real-time diagnostic information.

There are no circumstances under which I can envision a generic, application-wide manufacturer-recommended maintenance plan could have better operational and/or emissions-related results relative to the expert operator-tailored, time-tested and "conditions-based" maintenance plans under which we operate.

iii. Compression Package Operators are Highly Incentivized to Properly Maintain Their Expensive, Revenue-Generating Equipment and Should Not be Hindered in Those Efforts by the Imposition of Inflexible, Generic Requirements

Compression package operators are financially incentivized to ensure their compression packages, especially the engines that power those compression packages, are extremely well-maintained and properly and promptly repaired, as any failure to do so can be extremely costly to them and their customers.

Contract compression service providers' revenues can be significantly reduced through lost business and "downtime credits" if their provision of contract compression services is interrupted through equipment malfunction or excessive downtime for avoidable repairs. Preventive maintenance must be conducted expeditiously and successfully.

Additionally, a poorly maintained and operated compression package, including its engine, can suffer catastrophic failure requiring significant capital outlays if the equipment is not subject to a robust and time-tested preventive maintenance program.

Similarly, the life expectancy of the compressor package can be materially reduced from in excess of thirty years to significantly less, absent highly focused maintenance and repair efforts. Those additional capital outlays for replacement equipment are otherwise avoided by the development and application of expert-driven preventive maintenance plans, which is the domain of the operators, not the manufacturers and sellers.

iv. Expertise in the Operation, Maintenance and Repair of Engines Placed in Service Resides with the Operators, Not Manufacturers

Compression package operators are the experts in the operation, maintenance and repair of these engines, not manufacturers. My employer for the last twenty-one years, Archrock, has been doing this work for in excess of sixty-six years and owns the largest contract compression fleet in the United States. In addition to owning and operating the largest fleet of natural gas compressor packages in the United States, we also have an "aftermarket services" business segment that is engaged by third parties to maintain, repair and sometimes even operate the engines they own.

Manufacturers manufacture the engines and their operational experience comes in the form of (i) laboratory or other controlled testing environments involving controlled operating conditions and the use of pipeline-quality natural gas and (ii) the indirect experiences of the full spectrum of engines owners and operators, of which contract compressions providers are a part.

v. Air Regulators, Engine Manufacturers and Involved Stakeholders Agreed to Workable Framework

Operators and manufacturers of these engines, including The GCA members on whose behalf I am testifying, worked very closely with the EPA during the NESHAP Subpart ZZZZ comment period and collectively devised an approach that they concluded best serves all interested constituents. I continue to believe it is the right approach, and I rely on NESHAP Subpart ZZZZ §63.6625 as I continue to oversee the development, assessment, refinement and improvement of Archrock's operations and maintenance program.

That section reads in relevant part:

> "**§63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?**
>
> (e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) *according to the manufacturer's emission-related written instructions* ***or develop your own maintenance plan which must provide to the extent practicable for the maintenance***

and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. . . .” (emphasis added)

The GCA supports the adoption of the NESHAP Subpart ZZZZ approach to operation and maintenance plans and note that deviating from this federal standard in this regard would create inconsistencies that are overly difficult to track, complicated to follow and challenging to apply with respect to contract compression service providers' compression packages, which move interstate from time to time between various customers' various jobsites. Most importantly, a requirement to meet the manufacturer's minimum recommended maintenance schedule will provide no environmental benefit over alternative language that allows for a tailored plan consistent with good air pollution control practices.

vi. Examples of Differences between Manufacturers' Maintenance Schedules and Compressor Package Operators' Maintenance Schedules and Absence of Emissions Reduction Impact

There is no change that we would make to meet manufacturers' recommended maintenance practices that would result in reduced emissions. To the contrary, an inability to apply our time-tested maintenance practices would actually increase ozone precursor emissions, including through increased travel to and from our customers mostly remote sites, through otherwise unnecessary starts and stops of the compression package and through the premature replacement of still functional components (i.e., new ones need to be manufactured and shipped and old ones need to be transported away).

Using the G3516J Caterpillar engine as an example, we typically perform these preventive maintenance visits approximately every 112 days (but with an inspection every 56 days), whereas manufacturer recommendations might call for the maintenance to be performed every 30 days.

Mandating the latter results in a three-fold increase in vehicle emissions as well as compression package emissions associated with the required starts and stops, and without any evidence of improved engine operations or offsetting emissions reductions as a result of the tripled workload.

vii. Conclusion

Based on my experience and in light of the foregoing testimony, I strongly recommend Proposed Rule 20.2.50.113.C(1) NMAC be revised to allow owners or operators of natural gas compressor packages to operate, maintain and repair that equipment, including its engine, according to its own time-tested, contract compression application-specific, experience-based and expertized plan, as long as that plan is consistent with good air pollution control practices for minimizing emissions, as provided under existing NESHAP Subpart ZZZZ.

Specifically, I propose the following addition be made to the Proposed Rule 20.2.50.113.C(1) NMAC, as set forth in GCA Exhibit 2:

20.2.50.113 ENGINES AND TURBINES:

C. **Monitoring requirements:**

(1) Maintenance and repair for a spark-ignition engine, compression-ignition engine, and stationary combustion turbine shall ~~meet~~ be consistent with the minimum manufacturer recommended maintenance schedule or a schedule developed by the owner or operator that must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. 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.

B. The Proposed Rule's Equipment Monitoring Tags and Compliance Database Regulations

i. Proposed Rule 20.2.50.112.A(3)-(10) NMAC

Proposed Rule 20.2.50.112.A(3)-(10) NMAC contains requirements for "owners and operators of a source" to attach Equipment Monitoring Tags ("EMT") to each source requiring such physical tags and for the creation, population with source data and maintenance of that data related to those sources in a Compliance Database Report ("CDR").

For the reasons outlined below, it is my opinion, based on significant experience and responsibility for environmental compliance as part of the regulated community, that such requirements are too unclear to follow; too onerous to implement and abide by; highly impractical; create an unnecessary potential for controversy between equipment suppliers and operators; and result in significant costs for source owners and operators without any apparent environmental benefit. Moreover, they simply add an unnecessary administrative layer of burden on top of more substantive compliance requirements in the Proposed Rule that already fundamentally assure protections.

ii. Lack of Clarity

Industry participants, including contract compression service providers, cannot assess, plan for, address, and measure compliance with regulatory requirements that are drafted in a way that create uncertainty through their lack of clarity and specificity. For example, what is a "unit" for purposes of physically tagging with an EMT? Each of our compressor packages is defined by our customers and our industry as a "unit," but, as further detailed below, each such unit consists of a significant number of components, some of which might be considered "sources."

The non-exclusive list of examples of "type of source[s]" found in Proposed Rule 20.2.50.112.A(3)(c) NMAC begins broadly on what might be referred to in the industry as a "unit of equipment" or the like (e.g., tanks, VRU and dehydrators), but, the list then quickly jumps to a small component, one or more of which is embedded on some units of equipment (i.e., pneumatic controllers), and ends with an indeterminate and undeterminable "etc."

The combined lack of clarity around the meaning of a "unit" and a "source" subjects the core requirements of this Proposed Rule to varying interpretations and, therefore, later disagreements between industry participants and the NMED, as well as among industry participants, likely including disagreements between contract compression service providers and our customers.

The Proposed Rule 20.2.50.112.A(3) NMAC goes on to impose these requirements on the "owners and operators of a *source*" whereas Proposed Rule 20.2.50.112.A(4) NMAC requires that the EMT be installed and maintained by the "owner or operator of the *facility*." Since not all sources, such as contracted compression equipment, are owned or operated by the facility owner or operator, this unreconciled disparity creates yet another source of potential dispute between contract service providers like those represented here by The GCA and our customers, as to applicability and associated responsibilities.

Proposed Rule 20.2.50.112.A(3) NMAC also provides that the EMT shall provide, "at minimum," a list of seven different types of information. The "at minimum" qualifier leaves the Proposed Rule open to interpretation and later unilateral expansion of the information requirements by the NMED, all while imposing on owners and operators the burden of setting up systems, including a database, into which they must input and must store and maintain this data. The absence of clarity around the full scope of what might be required creates confusion and uncertainty, impairs database design (likely increasing burdens and costs associated with designing and maintaining undefined data entry slots for this yet to be defined information), and complicates compliance.

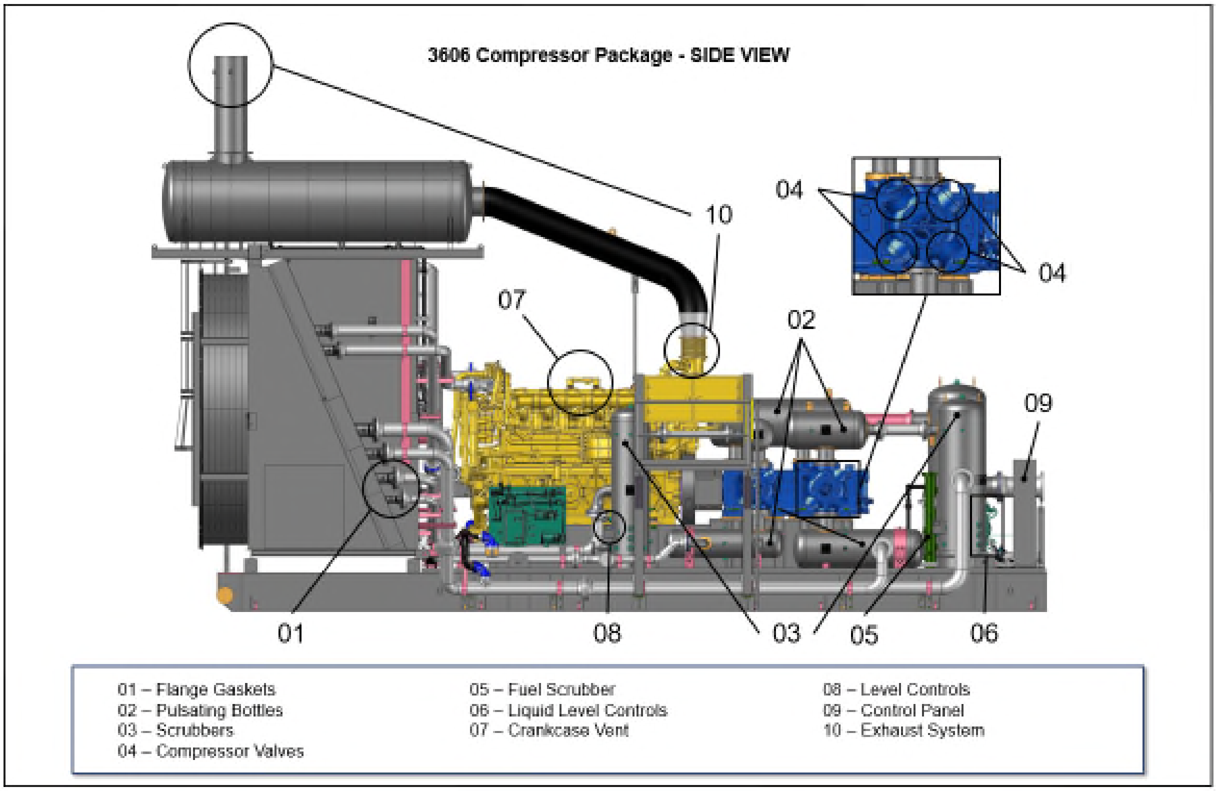
iii. Extremely Onerous and Impractical

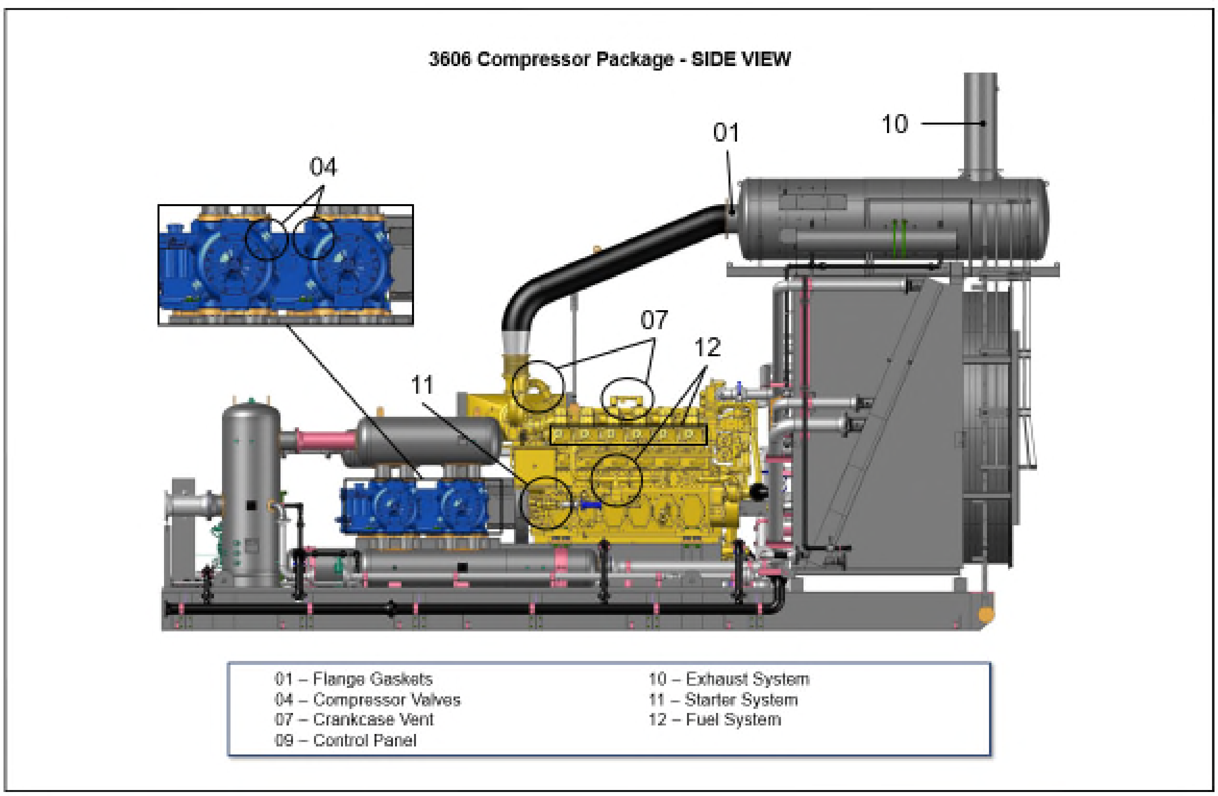
Acknowledging the lack of clarity of this Proposed Rule, which could result in varying interpretations of the nature and scope of the requirements, an analysis of those requirements makes clear that they are extremely onerous and overly burdensome on source owners and operators, including contract compression service providers, even if those requirements are read in their most constrained and limited light.

(1) Too Many Tagging Points Depending on How the Proposed Rule is Interpreted

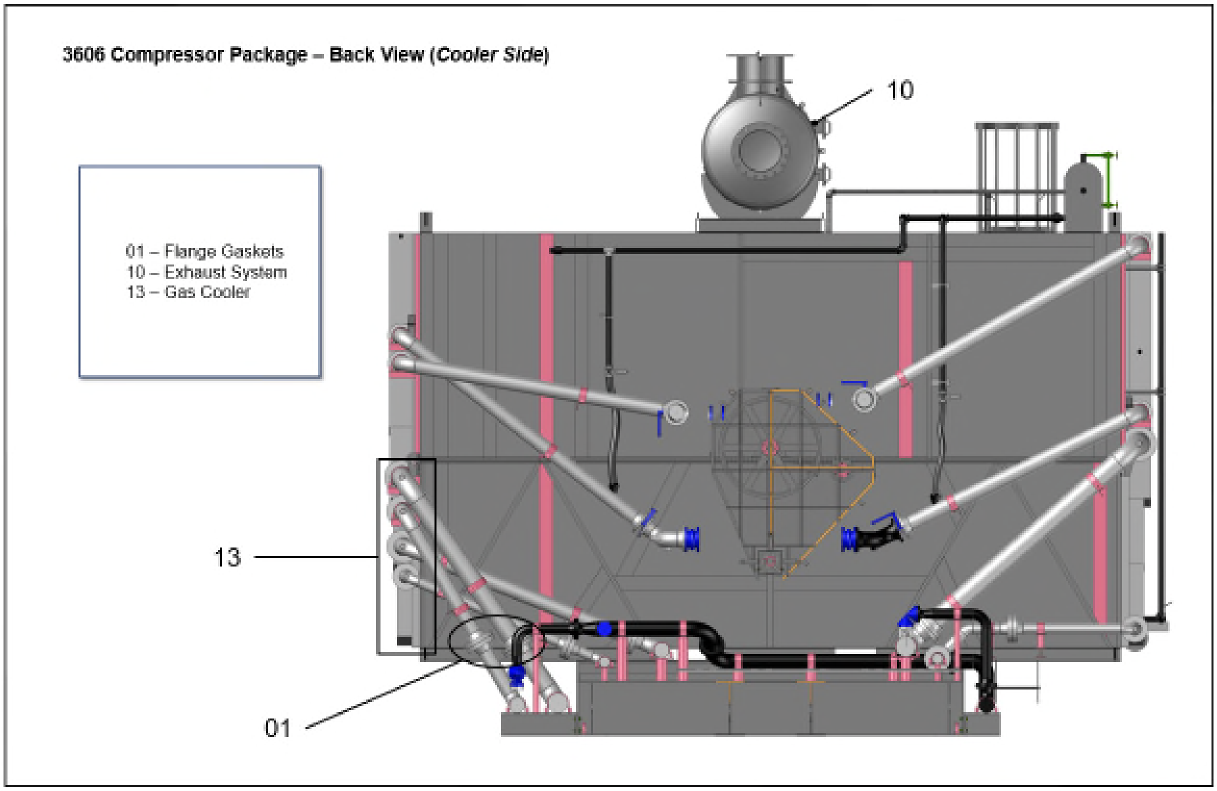
Our compression packages at the major component level consist primarily of an engine (which may employ an air/fuel ratio control system and catalyst), a compressor, a control panel, a cooler and a "skid" which serves as the foundation for the entire compression package. Depending on the size and type of the compressor package involved, there could be between 10 and 20 smaller components and devices, such as pneumatic controllers. Factoring in every pipe, hose, joint, valve, flanges and the like that could conceptually leak natural gas if it were to suffer a failure, there are another 145 "sources" on average. In total, the "sources" subject to the requirements as drafted could average 160 per compression package. That is 160 tagging, database entry, maintenance record maintaining obligations on each and every natural gas compression package deployed in New Mexico, or an estimated 76,200 EMT tags among the GCA members alone as of December 2020.

To illustrate the complexity of our natural gas compression packages, below are images depicting a relatively standard piece of equipment.





GCA Exhibit 15



(2) Many Sources Are Replaced, Not Maintained

The Proposed Rule is drafted as if all “sources” are of a type that is repaired and maintained and provides no accommodation for the numerous “sources” that are removed and replaced when they fail, their function diminishes or they are otherwise proactively replaced as part of a preventive maintenance plan, such as fuel valves.

For expended and expendable “sources,” the Proposed Rule’s requirements are not just burdensome, but seem wholly unjustified.

(3) Compression Packages and Their Individual Components are Swapped Out and Move In and Out of Various Jurisdictions

Contract compression service providers provide those services using compression packages that move all over the United States and under contracts ranging anywhere from six months to multiple years depending on the customer’s needs. At the end of a compression services contract, these compression packages are transported to another site in need of compression services, often resulting in them moving from state-to-state.

Because of their non-permanent placements, our compression packages may be in New Mexico for a relatively short period of time before being moved to another site for another customer, and it might never return. Utilizing an EMT in the context of sometimes relatively short contract compression service assignments would result in service providers tagging, logging and tracking information into the EMT related databased that operationally will not in any way require maintenance, repair or replacement before the compression services contract term ends. Specifically, the EMT-embedded information for the estimated 160 “sources” on a compression package deployed on a six-month compression services contract would not change during its term at that site, providing no valuable or actionable data to NMED, providing no emissions benefit (but likely causing an emissions detriment, as explained elsewhere) and simply creating a significant burden and resulting in a significant cost for service providers, facility owners and operators and ultimately New Mexico energy consumers.

When a component is replaced on a compression package, the replacement does not always come from within New Mexico. As a result, the EMT tagging requirement—at least to the extent it is tied to the other components on the same compression package and/or the compression package as a whole—becomes ineffectual, and at a high cost in terms of time and effort, as that new component would be assigned a new EMT that would not correlate with the original compression package. In other words, the EMT system would track individual components independently and not provide any longer term value as it relates to the original compression package as a cohesive whole.

(4) Tagging Impracticalities

Many "sources" are too small to adhere a tag sufficient to bear a RFID, QR or barcode and those of sufficient size to allow such attachment pose other problems, such as heat destroying the integrity of adhesive options and welding creating significant burdens, potential structural integrity problems and our safety concerns (i.e., welding at a natural gas operation).

Some perceived "sources" are not conducive to bearing hanging tags and hanging tags could pose a safety risk (e.g., interfering with the safe use of repair tools or risking "grabbing" the clothing of our field service technicians ("FSTs")).

Some tag-requiring sources could be physically inaccessible for tagging and/or for safe reading. Few tags could be read without the necessity of shutting off the equipment for safety reasons, which creates shut down and start up emissions otherwise avoidable absent this EMT concept.

Additionally, compression service sites are outdoors and involve large, industrial equipment that operates 24/7/365, so the tags would quickly become unreadable absent an FST manually cleaning each of the estimated 160 tags regularly before scanning them, tags will become corroded, tags will become faded from UV rays, tags will fall off and tags will become damaged and non-readable. Once a tag is missing, the data associated with that tag is lost unless there is also a "directory" of tags that shows each and every source that can be used to create a new tag with the same readable code.

(5) Contract Compression Service Providers Serve Many Customers

Contract compression service providers serve hundreds of discreet customers throughout New Mexico. Each such customer could choose a different tagging protocol and tagging format (RFID, QR or bar code) and impose those differing requirements on their service providers. A significant amount of time would be required to analyze, adopt and comply with those disparate requirements, and would require each of our FSTs to carry different readers and different tag types to each customer site since most FSTs serve multiple customers.

Similarly, each such customer will have its own unique database that contract compression service providers might be obliged to navigate to get data into and reports out of with respect to the "sources" on those service providers' supplied equipment. Additionally, if the database is created and maintained at the customer/facility owner or operator level and the contract compression services are terminated and the compression package is redeployed to a different customer, there is no way to preserve the history of the compression package's "sources" because the tags would be specific to the customer.

The Proposed Rule's implication of contract equipment and service providers by necessity creates a labyrinth-like maze of systems and processes that make our safe, environmentally compliant provision of that equipment and those services materially more challenging and, as outlined below, more expensive.

(6) Relies on Non-Existent Database System

Compliance with this Proposed Rule hinges on the development of an owner or operator-created database, a database that does not currently exist, that NMED has not offered to create and that would instead need to be created independently by each of the hundreds of owners and operators in New Mexico.

(7) Voluminous and Often Unavailable Data Required to be Accessible in the EMT

Proposed Rule 20.2.50.112.A(3) NMAC provides the minimum data each EMT must provide. While a limited portion of that data is viable for most or all sources (e.g., a unique unit identification number and type of source (subject to NMED clarification of the meaning of "source"), as set forth below, the other information on this non-exclusive list is either impossible, challenging or impractical/unnecessary to provide:

- **20.2.50.112.A(3)(b) NMAC requires location of the source.**
    - As mentioned above, some components of compression packages—and often the entire compression package itself—are fluid as to location and, as a result, this EMT system would, in the context of our industry, provide little or no consistent data, in particular as it relates to location.
- **20.2.50.112.A(3)(d) NMAC requires for each source, the VOC (and NOx, if applicable) PTE in lbs./hr. and tpy.**
    - The lack of clarity around the meaning of "source" means it might include any device that has the potential to be a source of emissions. Not all such sources have a defined release rate and, instead, only release emissions on an unexpected, unplanned basis and this information is not available for these types of sources. Furthermore, component manufacturers do not guarantee a PTE emissions factor, so there is no basis to make this determination. Even if they did, these values would vary depending on operating, site and gas conditions, which are different from facility to facility.
- **20.2.50.112.A(3)(e) NMAC requires for a control device, the controlled VOC and NOx PTE in lbs./hr. and tpy.**
    - Control device manufacturers do not guarantee a PTE emission factor. Rather, their guarantee provides a statement of what the control device can achieve under lab conditions, not what the control device may achieve with variable operating, site and gas conditions, namely fuel. Further, even if applicable to real world conditions, control device guarantees are provided

in percent reduction and would need to be converted to pound per hour (lb/hr) and ton per year (TPY) measurements. Currently, there is not a standard provided federally or by a state to calculate such numbers, so each EMT would have entirely different data that would likely be incomparable to other control devices or even other users of the same control device, therefore providing no value. These measurements are better tracked through the existing permit application process.

- **20.2.50.112.A(3)(f) NMAC requires make, model, and serial number.**
  - Either this information is visible on the source already or the information does not exist (namely serial number).
- **20.2.50.112.A(3)(g) NMAC requires a link to the manufacturer's maintenance schedule or repair recommendations.**
  - These are not always available online and, even if they are, my testimony explains at length why a contract compression service provider's maintenance schedule and repair recommendations are the appropriate measure. These schedules and recommendations are refined over decades of industry effort, expense and experience and, as such, should not be made available in any non-confidential form, including a scannable EMT, as they represent proprietary intellectual property and/or competitively sensitive trade secrets.

For all of the above mentioned reasons it is my opinion that the minimum required EMT data does not mitigate precursor ozone emissions, the viable data is already provided to NMED by the Permit/NOI holders (i.e., our customers) and is, therefore, repetitive without benefit, and the other information on the non-inclusive list is either impossible or impracticable/challenging to obtain with little to no merit and largely negatively impacts to safety.

v. Extremely Expensive

Development, implementation, maintenance, monitoring and reporting as called for by these requirements will be extremely expensive both for facility owners and for the service providers that utilize equipment that might contain "sources," such as we contract compression service providers.

Our back office operations already run leanly so that we can focus our labor attention to the safe, compliant and continuous provision of contract compression services to our customers. The development of the tools, equipment, systems and processes that would be required to comply with these requirements would require the engagement of additional staff members in our Information Technology Department and on my team, which develops systems and processes necessary to comply with applicable law in the field. Technology projects such as this at minimum cost in the hundreds of thousands of dollars. By way of example, a contracts database implementation we undertook a few years ago cost in excess of $400,000, and that was with a well-defined scope and clearly defined roles and responsibilities.

Our Supply Chain Management Department would likely need to add staff to source the scanning tools (one of each type for each of our >900 FSTs to ensure compliance with our customers' varying systems) and the tags (thousands of unique tags carrying one or more of the scanning formats).

We would probably need to add staff to our Air Quality Team and Health Safety & Environment Department to review, manage and maintain the data from the thousands of sources associated with our contract compression packages and to produce quality review and submit the CDR.

Most impactful and costly is the increase in headcount that would be required in the field to apply, maintain, clean and scan the EMT and research and replace lost EMT's. The market for FSTs is already extremely tight as a result of a high demand for highly skilled technicians, not just from within the energy industry, but also from other industries competing for the same low supply. If we were fortunate enough to find the additional FSTs to perform these requirements, we would have to do so at a pay rate inflated artificially by, among other things, customers and service providers in New Mexico scrambling to add them as a result of the Proposed Rule, notably including Proposed Rule 20.2.50.112.A (3)-(10) NMAC.

Adding to all of those expenses is the requirement of owners or operators to retain and pay for third party data and system auditors, which cost is accompanied by the administrative burden that any audit imposes on the audited entity.

vi. Without Clear Environmental Benefit and Proposed Changes are Without Environmental Detriment

Despite my decades of developing and implementing policies, practices and procedures geared toward complying with environmental requirements, I am unable to articulate a tangible environmental benefit that would justify these requirements even if they were non-onerous and free to implement. The EMT and CDR requirements would not be free to implement, of course, and appear to establish an extremely onerous program that would significantly increase our costs of operations, which costs ultimately gets passed on to and paid for by New Mexico energy consumers – all without increasing the enforceability of the Proposed Rule or the compliance demonstration information available to NMED.

As mentioned above, some tag-requiring sources could be physically inaccessible for tagging and/or for safe reading without the necessity of shutting off the equipment, which creates shut down and start up emissions otherwise avoidable absent this EMT concept.

Customer demand to add and/or scan EMT tags would result in additional emissions stemming from our FSTs driving to and from these mostly remote locations.

It is important to note that The GCA is not seeking to eliminate the extensive compliance demonstration and recordkeeping requirements established in the Proposed Rule. While The GCA seeks to eliminate the unnecessary overlay of the EMT and CDR requirements, this change would not eliminate the underlying requirement to contemporaneously track each compliance event for each source subject to emissions standards and monitoring under the Proposed Rule. See GCA Exhibit 8.

Likewise, the Proposed Rule would retain the requirement to create an electronic record of all monitoring events that includes: date and time of the testing, monitoring, or inspection event; name of the personnel conducting the testing, monitoring, or inspection; identification number and type of unit; a description of any maintenance or repair activity conducted; and result of any required testing, monitoring, or inspections. Proposed Rule 20.2.50.112.C(1) NMAC. As set forth in Proposed Rule 20.2.50.112.C(2) NMAC, those records must be retained for five years.

The Proposed Rule would also require an owner or operator to provide requested compliance demonstration information to the NMED upon request. Proposed Rule 20.2.50.112.D(1) NMAC. In an attempt to ensure prompt responses to such requests but also to account for weekends and holidays, The GCA has suggested a change to the proposed rule that would provide an owner or operator three business days, as opposed to 24 hours, to respond to such a request. See GCA Exhibit 8. The compliance demonstration requirements of the Proposed Rule are comprehensive and, even with the changes requested by The GCA, generally exceed the compliance demonstration requirements established in federal or other state rules that regulate sources in the oil and gas industry.

vii. Conclusion

Proposed Rule 20.2.50.112.A(3)-(10) NMAC would impose requirements that are too unclear to comply with; would be extremely onerous and impractical; are conditioned upon a database that does not exist; and would be extremely expensive to implement without any evidence of a resulting emissions benefit. As an energy industry and contract compression service professional for in excess of three decades, I do not see how these requirements can be assessed, implemented, followed or measured as currently written. As such, and unlike the other Proposed Rule sections upon which I am testifying, it is my expert opinion that these sections of the Proposed Rule be stricken in their entirety from Proposed Rule 20.2.50 NMAC rather than being modified.

The changes to the EMT/CDR requirements in the Proposed Rule that The GCA is seeking will not adversely affect the enforceability of the Proposed Rule, or diminish an owner or operator's obligation to create and keep records demonstrating compliance with all of the requirements of the Proposed Rule. The GCA simply seeks to eliminate the EMT/CDR overlay for the reasons outlined above.

C. The Proposed Rule's Fugitive Emissions/LDAR Regulations: Time to Tag Any Leak Discovered by AVO Inspection

i. Proposed Rule 20.2.50.116.C(1)(e) NMAC

Proposed Rule 20.2.50.116.C(1)(e) NMAC calls for a leak discovered by AVO inspection to be tagged and reported to "management [of the facility] or their designee" within three "calendar days" of discovery. Although contract compression service providers do not own facilities and will not be a part of the reporting to management process (unless we discover a leak on our equipment), our customers—the facility owners and/or operators—will likely ask that we tag any leaks discovered on our equipment on their behalf.

For a variety of logistical reasons explained below, The GCA simply asks that "calendar days" be changed to "business days" so that The GCA can more readily satisfy the requirement if asked to do so on our customers' behalf. Noteworthy is the fact that this recommendation does not include any requested extension of the time period during which the associated leak must be repaired under Proposed Rule 20.2.50.116.E NMAC, so The GCA's modest proposal has no real impact from the standpoint of emissions control. The GCA is not seeking a change to the repair deadline, and that deadline flows from when a leak is detected, not when the leaking component is tagged.

ii. Indirect Responsibility Requires Time to Convey

Although this proposed rule applies to the owner or operator of a facility, not the owner or operator of the contract equipment located at that site, it is not uncommon for responsibilities like these to be delegated to or expected of the contract service provider and equipment owner/operators, like contract compression service providers.

This indirect implication on our industry provides the basis for The GCA to comment, and the additional time required (a) for our directly obliged customers to convey the leak discovery and the tagging need to us and (b) for us to queue up the appropriate FSTs for the task is one of the reasons this modest additional time to conduct the tagging is warranted if there is an interceding weekend or holiday.

iii. Remote Facility Sites

Our customers' facilities at which we provide contract compression services using our compression packages are often quite remote and, unlike our average customers' personnel, our FSTs are not always present at those facilities. As such, travel is almost always required, sometimes from regional maintenance offices that serve as a central hub for multiple customers and those customers' multiple sites.

iv. Reduced Labor Availability on Weekends and Holidays / Increased Labor Costs

Although contract compression services are a must-run service with 24/7/365 operations, in light of the nature of the labor market for qualified FSTs, we try to honor holidays and weekends for all but a limited number of "on-call" FSTs. With that reduced weekend and holiday manpower, we attempt to direct those limited on-call FSTs toward highly impactful, urgent and emergency-type priorities. The reallocation of limited weekend and evening labor resource to administrative, non-technical, non-environmentally impactful tagging of identified leaks could result in a longer response time for the more urgent and technical service needs. These latter more urgent and technical tasks have the potential to have an environmental impact, whereas the completion of the tagging process does not.

While we do call upon the services of non-on-call FSTs in the case of unexpected urgencies, we endeavor to limit our reliance on our FST labor force during their hard-earned periods of downtime.

If we are required to address the administrative task of tagging within three "calendar days" rather than the proposed three "business days," we will be compelled to either (a) reprioritize our weekend and evening work among our limited number of on-call FSTs away from higher priority, higher impact tasks toward administrative tagging efforts, (b) increase the number of FSTs on-call (reducing their aggregate weekend and holiday time) or (c) increase FST headcount, which results in increased prices for our customers and end consumers, and which is increasingly more difficult in this technical service niche.

v. Potentially Detrimental Environmental Impact

The day or two delay in the administrative task of tagging in these instances creates no harm to the environment and the "calendar day" related earlier tagging creates no benefit. However, as mentioned earlier, if tagging is required on weekends and holidays, the assigned FSTs might be delayed in responding to environmentally impactful tasks. The reliance on "calendar days" rather than "business days" has no environmental upside, but does have a potential downside.

vi. "Business Day" Acknowledgment in the Proposed Rule and in NESHAP Subpart ZZZZ

Perhaps in light of the aforementioned logistical reasons, among other reasons, both this Proposed Rule and NESHAP Subpart ZZZZ refer to "business days."

The Proposed Rule refers to "business days" three times: 20.2.50.112.A(9)(a), 20.2.50.112.C(1) and 20.2.50.115.C(1)(e) NMAC.

NEHSAP Subpart ZZZZ refers to "business days" no less than seven times, including as it relates to oil changes instigated by bad samples, which must be performed with two "business days."

vii. Conclusion

Based on my experience and in light of the foregoing testimony, I believe Proposed Rule 20.2.50.116.C(1)(e) NMAC should be revised to allow three "business days" rather than three "calendar days" to manage the task of tagging if requested by the responsible party, our customers.

D. Deadline for NMED Approval of Alternative Monitoring Requests

i. Proposed Rule 20.2.50.112.B(1) and (2) NMAC

Proposed Rule 20.2.50.112.B(1) NMAC establishes inspection requirements that apply to the owner or operator of sources subject to emission standards and monitoring, to ensure proper maintenance and operation. Proposed Rule 20.2.50.112.B(2) NMAC further establishes a process by which an owner or operator can seek approval for "an equally effective, enforceable, and equivalent alternative monitoring strategy" and requires NMED to issue a written response approving or denying the requested alternative monitoring strategy, but does not establish any timeline for that response.

The GCA requests that a timeline be established for NMED's response to a request for approval of an alternative monitoring strategy. Such a request should not be allowed to languish or be denied by omission if NMED fails to act, as operational decisions and processes are dependent on the timely receipt of the requested response.

The GCA requests that language be added to Proposed Rule 20.2.50.112.B(2) NMAC to the effect that NMED will respond within a reasonable time, but in no event more than 90 days after receipt of an owner or operator's request for approval of an alternative monitoring strategy. *See* GCA Exhibit 5. This is a reasonable period of time to respond, and is supported by principles of good governance.

ii. Conclusion

As a person who has significant experience working with sources subject to environmental monitoring requirements, I recognize the value that the Proposed Rule adds by creating the potential for use of an alternative monitoring strategy. Similar concepts are found throughout state and federal environmental regulations. At the same time, as a person who has significant experience working to establish policies and procedures tied to environmental regulations, I appreciate the value that would be added by a requirement that NMED respond within a reasonable time, as well as a 90-day deadline for NMED's response.

The GCA's requested change will help with regulatory certainty, and also help ensure that an unreasonably delayed approval could not frustrate the purpose of the alternative monitoring program included in the Proposed Rule.

IV. Testimony Conclusion

In conclusion, I and The GCA ,on whose behalf I submit this written testimony, understand and respect our collective obligation to do what we feasibly can to protect the environment in all jurisdictions in which we operate, including New Mexico, while also helping, together with our customers, provide New Mexico citizens' jobs and the fuels that help power their vehicles and homes.

The GCA's proposed modifications to the Proposed Rule are offered with a goal of maintaining the integrity of NMED's core objectives, while helping make the Proposed Rule's requirements clearer to those affected, more feasible, more cost-effective, less environmentally detrimental, more technologically viable, and less unduly administrative and burdensome. We believe The GCA's proposed modifications satisfy those objectives, and respectfully ask the EIB to enact our suggested changes after giving them due consideration.

This concludes my direct testimony in this matter.

Mark Copeland

Experience

Archrock (and predecessors) — 06/2000 - Present

Director, Field Operations Support and Service 03/2006 – Present Houston, TX

- Oversee development of operations and maintenance process improvements
- Oversee Operation Support Center (24/7/365 call-in center)
- Develop budgetary objectives and plans to meet expectations
- Implement plan and rollout of new Service Delivery Model for North America
- Reliability and Warranty group responsibilities
- Field Compression Analytics
- Monitor compliance with NESHAP ZZZZ and NSPS OOOO

Regional Manager 03/2003 – 03/2006 Farmington, NM

- Directed all business activities within the Southern Rockies Region, including Service Delivery, Sales and Facilities
- Managed budgetary responsibilities for P&L of $60M revenue

General Manager 06/2000 – 03/2003 Houston, TX

- Directed all business activities for 120,000 sq ft facility, including Sales, Engineering, Inventory and Fabrication
- Managed budgetary responsibilities for P&L of $80M revenue

PAMCO Services International — 08/1998 – 06/2000

Senior Project Manager Houston, TX

- Managed all packaging of compression fleet in the Houston facility
- Directed sales and office staff to reach targets set by management team
- Ensured effective utilization of company assets and resources

J-W Operating — 05/1989 – 08/1998

District Manager 04/1994 – 08/1998 Midland, TX

- Opened new office for J-W
- Directed all business activities for the Permian Basin, including Service Delivery, Sales and Facilities
- Ensured effective utilization of company assets and resources

District Manager 05/1989 – 03/1994 Lafayette, LA

- Directed all business activities for the Gulf Coast Region, including Service Delivery, Sales and Facilities
- Ensured effective utilization of company assets and resources

Education

Southern Methodist University Graduated 1983

BS Mechanical Engineering

STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF:

PROPOSED NEW REGULATION
20.2.50 Oil and Gas Sector — Ozone Precursor Pollutants **No. EIB 21-27(R)**

PRE-FILED TECHNICAL TESTIMONY OF MR. RAYMOND CARR,
A WITNESS ON BEHALF OF THE GAS COMPRESSOR ASSOCIATION

I. Introduction to My Testimony

My name is Raymond Carr. I am testifying as a technical witness on behalf of The Gas Compressor Association (The GCA) in this proceeding. My testimony supports The GCA's proposed amendments to the New Mexico Environment Department's (Department) proposed regulations set out as 20.2.50.7 NMAC and 20.2.50.122 NMAC in the Department's proposed rule, 20.2.50 NMAC (Proposed Rule). The GCA's proposed amendments to these provisions are set forth in GCA Exhibit 3.

This testimony begins with an overview of my credentials. I will then go on to discuss the Department's proposed regulations concerning pneumatic controllers, specifically as proposed in 20.2.50.122 NMAC. I will then go on to describe The GCA's proposed amendments to the Proposed Rule related to pneumatic controllers, and will explain why these proposed amendments are necessary.

II. Statement of My Qualifications and Relevant Experience.

My resume is attached as GCA Exhibit 18. I received a Bachelor of Science degree from the University of Tulsa in engineering physics, with a specialization in electrical engineering, in May 1988. While in school, I worked as a student technician for the Tulsa University Artificial Lift Projects, a research consortium funded by major oil companies to research artificial lift methods for crude oil production. Since May 1988, I have been a registered Engineering Intern in the State of Oklahoma.

I have been working for Frank W. Murphy Mfr. (later renamed FW Murphy Production Controls) since May 1988. During my thirty-three year career at FW Murphy Production Controls (FW Murphy), I have served as R&D Engineer, a Chief Engineer in the Automation Division, an Engineering Supervisor of Corporate Sales, an Engineering Supervisor for Corporate Development, a Sales Engineering Manager for FW Murphy's Southern Division in Rosenberg, Texas, a Manager for Murphy Communications Solutions, a Manager Oil & Gas Market Development, a Manager Technical Marketing Support, a Manager for Technical Services, a Senior Engineer of Technical Services, a Manager of Technical Services, and an ASC Centurion Integration Specialist.

During my tenure with FW Murphy, I have learned about all Murphy products and applications, primarily in the oil and gas marketplace. My first experience with Murphy's scrubber level products in the field and in manufacturing was in 1988. I have given technical and training presentations at oil and gas industry trade shows and have taught the Instrumentation and Controls section of the EGSA Rowley Schools of On-Site Power Generation. My experience makes me an expert on FW Murphy Production Controls Scrubber Level Systems (SLS).

I am also familiar with pneumatic controllers and how they are used in the oil and gas industry. A Pneumatic controller is a mechanical device designed to measure temperature, pressure, or liquid level and transmit a pneumatic signal that will direct an event to occur – for example, a controller will measure liquid level and then direct a valve to open when the measured level reaches a pre-set point. Natural gas-driven pneumatic controllers are pneumatic controllers powered by pressurized natural gas, and are commonly used in New Mexico oil and gas operations.

For purposes of my testimony, there are three basic categories of controllers: continuous bleed controllers, which have a continuous flow of natural gas to the process control device (and are further divided between high-bleed and low-bleed, depending on whether the bleed rate is greater or less than six standard cubic feet per hour (scfh)); intermittent controllers, which reduce emissions when compared to continuous-bleed controllers by performing a similar function while not experiencing continuous bleed or venting; and zero-emitting controllers, which are either electric or, if natural-gas driven, are closed-loop and release gas not to the atmosphere but back into a pipeline.

III. The New Mexico Environment Department's Proposed Regulations Concerning Pneumatic Controllers and Pumps and GCA's Proposed Amendments to Them

The Department's Proposed Rule includes regulations specifically applicable to pneumatic controllers and pumps. *See* Proposed Rule, 20.2.50.122 NMAC. The Department's Proposed Rule further includes pneumatic control emissions standards, which are set forth in proposed regulation 20.2.50.122.B(4) NMAC. The Department's proposed regulations concerning the emission standards for pneumatic controllers provide standards for new and existing natural gas-driven pneumatic controllers and pumps, but omits an important class of pneumatic controllers whose design align with the emissions reduction goals of the Department's Proposed Rule — snap-acting (intermittent bleed) pneumatic controllers. As set forth in GCA Exhibit 3, The GCA proposes specific amendments to the Department's Proposed Rule concerning pneumatic controllers in order to clarify, fully capture and appropriately regulate the types of pneumatic controllers and pumps that are subject to the Department's Proposed Rule. I will now discuss the amendments and the basis for adopting them.

The GCA first suggests adding a definition of "intermittent pneumatic controllers" in 20.2.50.7 NMAC to clarify that such controllers are very different from continuous bleed controllers. This clarification is needed to ensure that emission standards under the Department's Proposed Rule that are made applicable to continuous bleed controllers are not applied to intermittent pneumatic controllers. Without the distinction, the beneficial use of intermittent pneumatic controllers in the oil and gas industry would be discouraged rather than encouraged. Intermittent pneumatic controllers are used widely in the oil and gas industry as a practical and effective means of limiting emissions.

The GCA's proposed amendments contemplate removing intermittent pneumatic controllers from regulatory provisions applicable to continuous bleed controllers in 20.2.50.122 NMAC, and instead proposes combining them with non-emitting devices, based on the fact that emissions are limited and often de minimus, as shown by the FW Murphy SLS (Scrubber Level System) Gas Emissions Calculator Spreadsheet attached as GCA Exhibit 19. As background, FW Murphy Production Controls product, LS200NDVO is an intermittent, low-bleed device. See FW Murphy Liquid Level Switches (LS200 Series), attached as GCA Exhibit 20, and FW Murphy Scrubber Level Control Systems, attached as GCA Exhibit 21. It qualifies as a low-bleed device based on the traditional threshold of 6 SCFH that is used to determine whether a continuous-bleed controller is high or low-bleed – though it has even lower emissions than a continuous, low-bleed controller, due to its intermittent operation. See the Report on Oil and Natural Gas Sector Pneumatic Devices, p. 41, by the U.S. EPA Office of Air Quality Planning and Standards, attached as GCA Exhibit 22. The LS200NDVO has connections for the venting of gas to an available Closed Vent System to further limit emissions. These types of devices should be exempted from monitoring and recordkeeping requirements by language The GCA proposes in 20.2.50.122.C(1) and 20.2.50.122.D NMAC, and their use should be encouraged along with non-emitting controllers, or where non-emitting controllers are not technically or economically feasible, by language The GCA proposes in 20.2.50.122.B NMAC.

By emitting only during the actuation cycle, intermittent controllers represent a significant reduction in emissions over traditional continuous-bleed pneumatic controllers, and the New Mexico ozone precursor rule should be revised to recognize that environmental benefit and to reward (and incentivize) their use. For that reason, the Department should treat intermittent pneumatic controllers like non-emitting controllers in the Proposed Rule. As shown in GCA Exhibit 3, The GCA has suggested changes that require owners or operators to maintain information about the number and design of intermittent controllers in their controller database, but otherwise exempt intermittent controllers from ongoing monitoring and maintenance requirements that are unnecessary as applied to intermittent controllers.

Treating intermittent controllers like non-emitting controllers in the ozone precursor rule makes sense from a technical standpoint. For example, the LS200NDVO intermittent controller model mentioned above is factory calibrated for the application for which it is intended, and no field adjustment should be necessary. The type of ongoing inspection, monitoring, and maintenance program that would be employed for a traditional, continuous-bleed controller does not serve the same purpose or provide the same benefits in the context of intermittent pneumatic controllers. An intermittent controller, which has no activity or emissions outside of the actuation cycle, will have nothing to inspect during the type of periodic inspection that one might conduct for continuous-bleed controllers. Moreover, if some equipment component of the system has a fugitive emissions leak, that leak will be subject to and captured by the fugitive emissions monitoring leak detection and repair (LDAR) program that is established elsewhere in the Proposed Rule.

Finally, GCA proposes language changes to 20.2.50.122.C(1) NMAC to refer to a controller's "emission rate" rather than it "bleed rate." This is because certain controllers that may not have a bleed rate of zero, such as certain low-bleed controllers, can effectively have an emission rate at or close to zero where the kind of Closed Vent System described above is employed. Consistent with the Department's goals of limiting emissions, it makes sense to use emission rates rather than bleed rates in the regulation of pneumatic controllers or pumps.

Conclusion

In conclusion, the amendments The GCA has proposed would encourage, rather than discourage, the continued use of intermittent pneumatic controllers in the oil and gas industry. The GCA's proposed amendments address the Proposed Rule's neglect of these types of pneumatic controllers by offering a definition that explicitly recognizes intermittent pneumatic controllers in the regulation and avoiding application of the emission standards that are applied to continuous bleed controllers.

This concludes my direct technical testimony in this matter.

Contact

www.linkedin.com/in/raymond-carr-26969431 (LinkedIn)

Top Skills

Testing
Engineering
Manufacturing

Raymond Carr

ASC Centurion Integration Specialist at FW Murphy Production Controls
Tulsa

Experience

FW Murphy Production Controls

4 years 9 months

ASC Centurion Integration Specialist
January 2020 - Present (1 year 7 months)
Tulsa, Oklahoma, United States

Mgr., Technical Services
November 2016 - January 2020 (3 years 3 months)
Tulsa, Oklahoma Area

Enovation Controls

Mgr., Technical Services
January 2013 - November 2016 (3 years 11 months)
Tulsa, OK

Co-manage department, provide problem solving services and technical support to customers

FW Murphy

10 years

Sr. Technical Services Engineer
September 2009 - December 2012 (3 years 4 months)
Tulsa

Perform problem solving on projects as directed by the Director of Quality and Customer Service

Mgr., Technical Services
January 2003 - September 2009 (6 years 9 months)
Tulsa

Managed department, provided customer support and problem solving services

FW Murphy

2 years

Mgr., Technical Marketing Support

GCA Exhibit 18

2001 - 2002 (1 year)

Mgr., Oil & Gas Market Development
2000 - 2001 (1 year)

Created Product Specifications based on Customer Input, Edited and Created Marketing literature, Promoted products at customer and internal presentations

FW Murphy
Mgr., Murphy Communications Solutions
1999 - 1999 (less than a year)

Managed department, explored communications technologies for remote monitroing of equipment, created packaged solutions for monitoring, directed one engineer and one adminstrative assistant

Frank W. Murphy, Mfr.
Engineering Supervisor, Corporate Development
1997 - 1999 (2 years)
Tulsa

Developed product specifications based on customer input, developed and executed product testing, edited and created marketing literature in conjunction with marketing department, promoted products by performing presentations to customers and internal associates

Frank W. Murphy Mfr.
Sales Engineering Manager, Southern Division
November 1997 - November 1998 (1 year 1 month)
Rosenberg, TX

Managed a team of engineers providing quotations to customer specifications, programming and designing custom control systems, performing shop tests and start-up assistance, and problem solving. Provided training and guidance to build team capabilities.

Frank W. Murphy, Mfr.
5 years

Engineering Supervisor, Corporate Sales
1993 - 1996 (3 years)
Tulsa

Traveled extensively working with outside sales force to promote product, provide training on newer products and technology. Supported distributors,

GCA Exhibit 18

assisted in developing custom control panel sales and design in Mexican subsidiary

Chief Engineer, Automation Division
1991 - 1993 (2 years)
Catoosa, OK

Provided quotations and designs for custom control panels to customers' requirements, programmed controllers, and worked with team of sales engineers. Performed shop testing and acceptance testing and equipment start-up assistance. Performed problem solving and troubleshooting as needed.

Frank W. Murphy, Mfr.
R & D Engineer
May 1988 - 1990 (2 years)
Catoosa, OK

Education

University of Tulsa
Bachelor of Science in Engineering Physics, Physics and Electrical Engineering · (1984 - 1988)

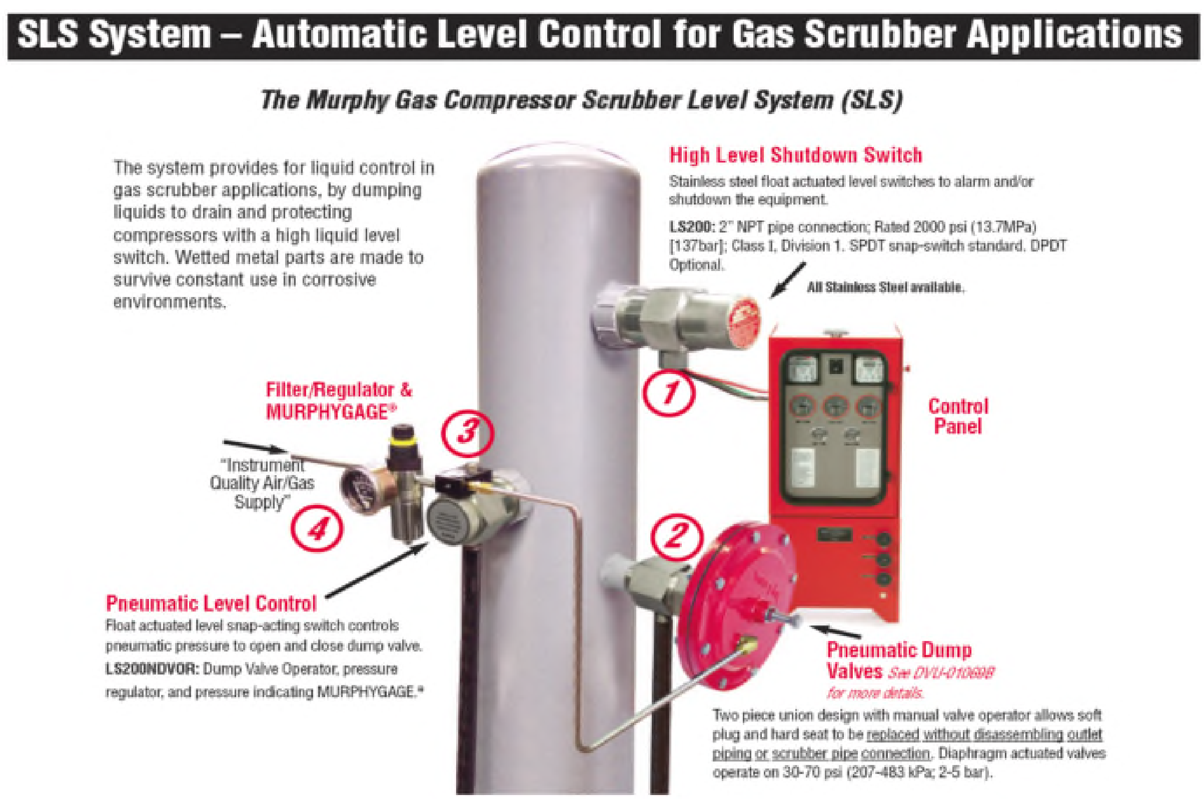
Edison High School
· (1977)

GCA Exhibit 18

FW Murphy SLS (Scrubber Level System) Gas Emissions Calculator

Please answer the following questions about your application		
How many times per hour does you scrubber dump?	10	
How long is one dump cycle in seconds?	10	seconds
Select from the list the nominal size of your DVU supply line.	1/4	inches
How long is the tubing or hose between the LS200NDVO and the DVU in feet?	6	feet
What is the supply pressure to the LS200NDVO in psi?	30	psi
What is the ambient temperature (°F) at the time of concern?	90	°F

Total System Emission of Gas per hour	0.626 scfh

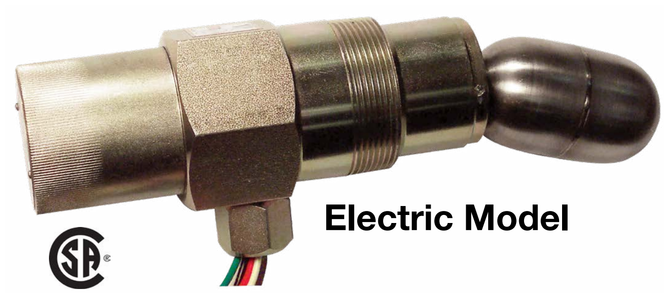


Liquid Level Switches
LS200 Series

Designed for harsh gas compressor scrubber applications, the LS200 Series Liquid Level Switches feature a robust design that trips on rising liquid level only. With both electric and pneumatic models available, the instruments screw directly into the vessel or can be mounted via an external float chamber. The nickel-plated body provides enhanced corrosion protection while the 304 stainless steel float operates in 0.55 specific gravity and heavier fluids. Additional features include:

- Rated for 2000 psi (13.8 MPa) [138 bar] working pressure
- Listed for cCSAus Class I, Div 1, Grps C & D locations
- Canadian registered
- Stainless steel models available for corrosive atmospheres

The LS200 Series replaces the FW Murphy Series L1200 Liquid Level Switches. The MSLS (Scrubber Level System) replaces the LS200 high-level shut-down switch with the MLS-020 magnetic level switch.



Electric Model

Pneumatic Model

Models

LS200 Liquid Level Switches with 2 in. NPT mounting are float activated to operate an electrical SPDT snap-switch (optional DPDT on some models) for alarm or shutdown of an engine or electric motor. The LS200 connects directly into the vessel wall and can be used with an FW Murphy weld collar or FW Murphy external float chamber.

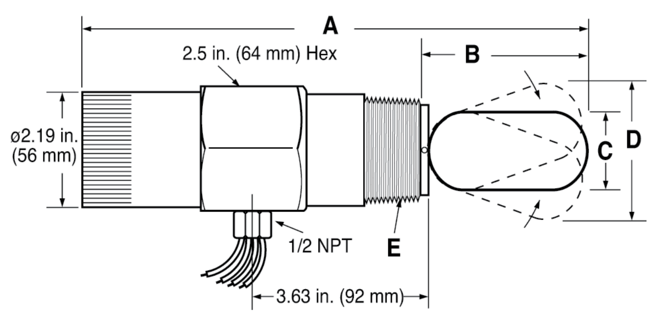
LS200NDVOR is a float-activated, pneumatic-vent level device used to operate DVU Series dump valves or similar devices. It provides a 2 in. NPT mounting with a pneumatic output for interfacing with pneumatic devices such as the FW Murphy pneumatic dump valve or other pneumatic instrumentation.

LS200NDVO is the Dump Valve Operator (DVO) without the pressure regulator for those applications where the system provides a filter regulator for instrument-quality air or gas as the control medium.

LS200N is the pneumatic level switch without the DVO or filter regulator. Please note: pneumatic media devices require clean, dry, instrument-quality air or gas.

Dimensions

LS200, L1100



	LS200	L1100*
A	10.16 in (258 mm)	11 in. (279 mm)
B	3.44 in. (87 mm)	3.50 in. (189 mm)
C	1.75 in. (44 mm)	1.56 in. (40 mm)
D	2.80 in. (71 mm)	3.4 in. (71 mm)
E	2 NPT	1-1/2 NPT

* The L1100 has been discontinued and remains in the table for reference purposes only.

GCA Exhibit 20

Application Data

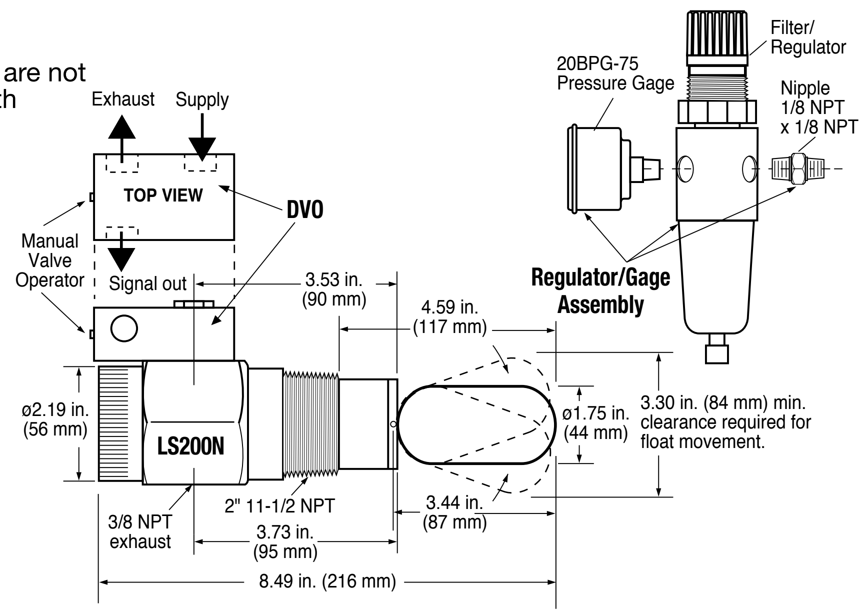
Pipe Data				
Nom. Size (inches)	O.D. (inches)	Schedule Number	Wall Thickness (inches)	Inside Diameter (inches)
3	3.5	40ST	0.216	3.068
3	3.5	80XS	0.3	2.9
4	4.5	40ST	0.237	4.026
4	4.5	80XS	0.337	3.826

Minimum Clearance				
	Insertion Depth (inches)		Vertical Clearance (inches)	
Product	Std.	w/ 1" Extension	Std.	w/ 1" Extension
LS200	4.6	5.6	2.8	3.15
LS200N	5.43	6.4	3.3	3.9
L1200	4.65	5.7	3.9	4.55
L1200N	5.6	6.7	5.3	6.9
L1100	4.4	5.4	3.4	4.05

Models L1200, L1200N and L1100 are discontinued and remain in the table for reference purposes only.

LS200N, LS200NDVO and LS200NDVOR with Dump Valve Operator, Pressure Regulator and Gage

CAUTION:
LS200 Series parts are not interchangeable with the L1200 Series.



Accessories

Refer to LS200 installation and operation manual for additional information.

External Float Chamber
Operating Pressure: 2000 psi (13.8 MPa) [138 bar]
Operating Temperature: 400° F (204° C)

Weld Collar
Operating Pressure: 2000 psi (13.8 MPa) [138 bar]
Operating Temperature: 400° F (204° C)

Float Shaft Extension
LS200 Series: 1 in.

LS200 Minimum Allowable Specific Gravity			
Model	Float Extension Length (inches)	Pressure (psi)	Specific Gravity
LS200	0	2000	0.55
	1		0.7
LS200NDVO	0	2000	0.63
	1		0.73

Specifications

<u>All Models</u>
Listed for cCSAus Class 1, Div 1, Grps C & D Locations
Canadian Registration Numbers (issued by ABSA):
LS200: 0F01476.2
L1200, L1200N and L1100 Series: 0F01476.0
Body: Nickel-plated; optional 316 stainless steel
Float: 304 stainless steel
Pressure Rating: 2000psig (13.8 MPa) [138 bar]

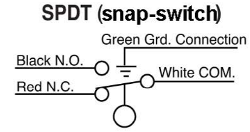
LS200
O-ring: Viton
Process Connection: 2" NPT
Temperature Rating: -20° to 300°F (-29° to 149°C)
Electrical: SPDT std.
Wiring: 18 AWG x 36 in. (1.0 mm^2 x 916 mm)

LS200NDVOR
Process Connection: 2" NPT
DVO Valve: 3-way N.C. w/manual operator, all connections 1/8" NPT (minimum 30 psig required)
Filter/Pressure Regulator Set:
Regulator: 0 to 75 psig (0 to 517 kPa) [0 to 5.17 bar] range
Maximum Input Pressure: 300 psig (2.07 MPa) [20.7 bar]

LS200NDVO
Process Connection: 2" NPT
DVO Valve: 3-way N.C. w/manual operator, all connections 1/8" NPT
LS200N
Process Connection: 2" NPT
Vent Valve: 2-way N.C. w/ 1/16 in. (2 mm) orifice and Viton seat; Inlet: 1/8" NPT; Outlet: 3/8" NPT

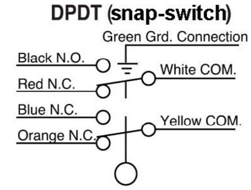
Electrical

SPDT (snap-switch)



Switch Rating: 5 A @ 125-250- 480 VAC
1/2 A @ 125 VDC
1/4 A @ 250 VDC
2A @ 6-30 VDC Resistive
1A @ 6-30 VDC Inductive

DPDT (snap-switch)



Switch Rating: 10 A @ 125-250 VAC
1/2 A @ 125 VDC
1/4 A @ 250 VDC
10 A @ 6-24 VDC
Inductive/Resistive

How to Order

Options listed below. All configurations may not be available. Call your sales representative or FW Murphy for more information.

LS200	–	D

Base Model
LS200
LS200N
LS200NDVO
LS200NDVOR
LS200SS
LS200NSS
LS200NSSDVO
LS200NSSDVOR

Options
D = DPDT

Approximate Shipping Weight and Dimensions		
Model	Weight	Dimension
LS200	6 lb. 12 oz.	13-1/2 x 4-1/2 x 3-1/2 in.
LS200SS	6 lb. 13 oz.	13-1/2 x 4-1/2 x 3-1/2 in.
LS200N	5 lb. 1 oz.	13-1/2 x 4-1/2 x 3-1/2 in.
LS200NDVO	5 lb. 15 oz.	13-1/2 x 4-1/2 x 3-1/2 in.
LS200NDVOR	6 lb. 8 oz.	13-1/2 x 4-1/2 x 3-1/2 in.

Part Number	Description	Notes
15700799	External Float Chamber	
15050375	Weld Collar	Shipping Weight: 6 lb. (2.7 kg)
15000478	1 in. Float Shaft Extension	LS200 Series
15010216	Dump Valve Operator Assembly	DVO, new style

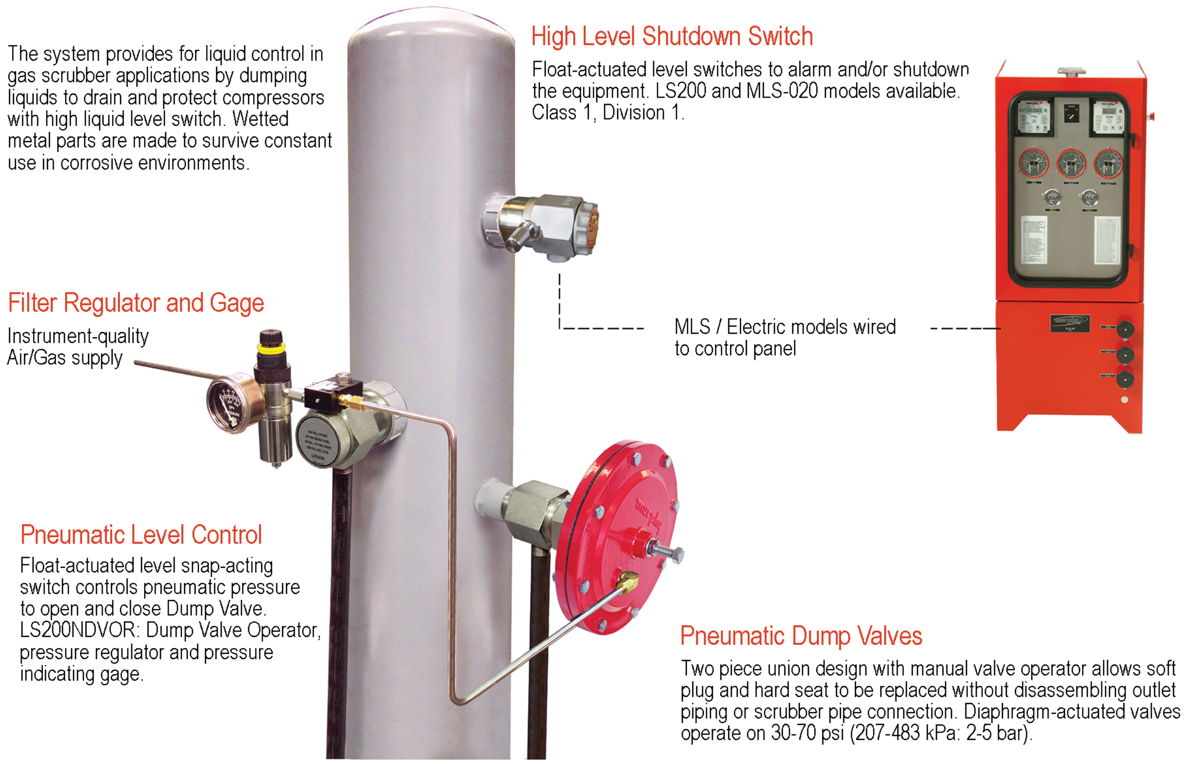
Note: Refer to the Installation and Operation manual 00-02-0671 for replacement parts at fwmurphy.com.

FW MURPHY™
PRODUCTION CONTROLS

Scrubber Level Control System (SLS)

Automatic Level Control for Gas Scrubber Applications

The FW Murphy Gas Compressor Scrubber Level System



You Save Money By Purchasing The SLS System Which Includes the Following:

- **LS200, MLS-020*** High Level Shutdown Switch
- **DVU**** Pneumatic Dump Valve
- **LS200NDVOR** Pneumatic Level Control with:
- **Filter Regulator with Gage**

  For detailed information on Level Switches and Dump Valves visit www.fwmurphy.com.

* Choose model using the How To Order matrix.

**Specify Dump Valve model when ordering.

Service Tip

The Gage and Filter/Regulator on the LS200NDVOR help keep the control medium clean and dry. It also allows operator to adjust pressure to recommended level of 30-70 psig. The Gage and Filter/Regulator are recommended to help increase system life and trouble-free operation.

Level Switches

- Designed for Harsh Gas Compressor Scrubber Applications
- Stainless Steel Float: Specific gravity varies by model and configuration, see Specific Gravity.
- For Separators/Scrubbers rated for up to 2000 psi (13.8 MPa) [138 bar] Working Pressure
- Electric and Pneumatic Models Available

Dump Valve Operator/ Dump Valve

- Hex Union Allows Plug and Seat Replacement Without Piping Removal
- Operates on 30–70 psi (207–483 kPa) [2.07–4.83 bar] Control Pressure
- Manual Valve Operator

GCA Exhibit 21

Specific Gravity

Minimum Allowable Specific Gravity			
Model	Float Extension Length (inch)	Pressure (psi)	Specific Gravity
LS200	0	2000	0.55
	1		0.7
LS200NDVO	0	2000	0.63
	1		0.73
MLS-020	0	2000	0.5
	1		0.65

How To Order

Approximate Shipping of SLS2120 model
Weight:19 lb. 6 oz. (8.7 kg)
Dimensions: (w x h x d) 15 x 15 x 12 in. (381 x 381 x 305 mm)

SLS

The SLS Kits Include LS200, LS200NDVO and a DVU Valve.

SLS150 – LR

Options		
Blank	=	Include Filter/ Regulator
LR	=	Less Regulator

Model	Dump Valve	Inlet	Outlet	Trim Size	Maximum Working Pressure
SLS150	DVU150	1" NPT	1/2" NPT	0.359 IN. (9 MM)	1800 psi
SLS175	DVU175	1" NPT	3/4" NPT	0.359 IN. (9 MM)	1800 psi
SLS2120	DVU2120	2" NPT	1" NPT	0.436 IN. (11 MM)	2000 psi

MSLS

The MSLS Kits Include MLS-020, LS200NDVO and a DVU Valve.

MSLS150 – LR TF

Options		
Blank	=	Include Filter/ Regulator
LR	=	Less Regulator

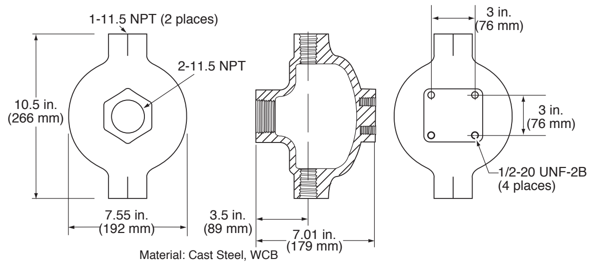
Options		
Blank	=	Without Test Function
TF	=	Test Function

Model	Dump Valve	Inlet	Outlet	Trim Size	Maximum Working Pressure
MSLS150	DVU150	1" NPT	1/2" NPT	0.359 IN. (9 MM)	1800 psi
MSLS175.5*	DVU175	1" NPT	3/4" NPT	0.359 IN. (9 MM)	1800 psi
MSLS175	DVU175	1" NPT	3/4" NPT	0.359 IN. (9 MM)	1800 psi
MSLS2120	DVU2120	2" NPT	1" NPT	0.436 IN. (11 MM)	2000 psi

*Substitutes L1200NDVO for LS200NDVO for 0.5 specific gravity applications

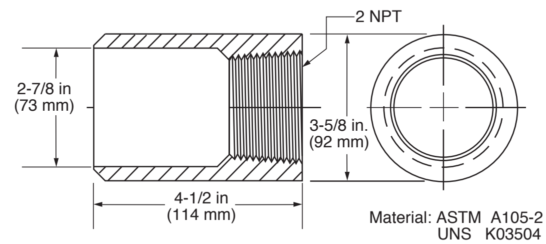
Accessories

Float Chamber 15051098



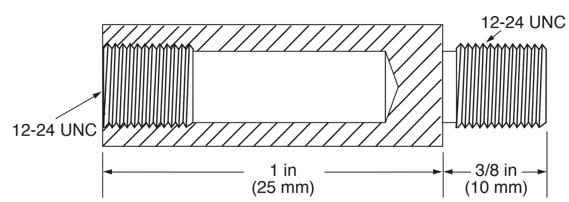
Operating Pressure: 2000 psi (13.8 MPa) [138 bar]
Operating Temperature: 400 deg F (204 deg C)
Shipping Weight: 32 lb. (14.5 kg)

Weld Collar (LS200 only) 15050375



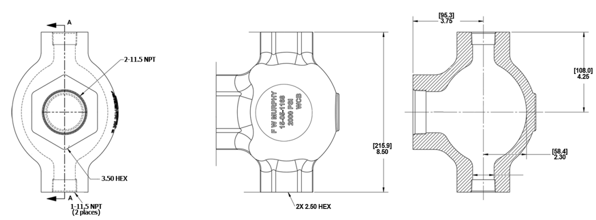
Operating Pressure: 2000 psi (13.8 MPa) [138 bar]
Operating Temperature: 400 deg F (204 deg C)
Shipping Weight: 6 lb. (2.7 kg)

Float Shaft Extension 15000478



Material: AISI 303, UNS-S30300

Series 100 Float Chamber 15700799



Operating Pressure: 2000 psi (13.8 MPa) [138 bar]
Operating Temperature: 400 deg F (204 deg C)
Shipping Weight: 18 lb. (8.16 kg)

FW MURPHY PRODUCTION CONTROLS
SALES, SERVICES & ACCOUNTING
4646 S. HARVARD AVE.
TULSA, OK 74135

CONTROL SYSTEMS & SERVICES
105 RANDON DYER ROAD
ROSENBERG, TX 77471

MANUFACTURING
5757 FARINON DRIVE
SAN ANTONIO, TX 78249

DOMESTIC SALES & SUPPORT
FW MURPHY PRODUCTS
PHONE: 918 957 1000
EMAIL: INFO@FWMURPHY.COM
WWW.FWMURPHY.COM

FW MURPHY CONTROL SYSTEMS & SERVICES
PHONE: 281 633 4500
EMAIL: CSS–SOLUTIONS@FWMURPHY.COM

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Oil and Natural Gas Sector Pneumatic Devices

Report for Oil and Natural Gas Sector Pneumatic Devices

Review Panel

April 2014

Prepared by

U.S. EPA Office of Air Quality Planning and Standards (OAQPS)

GCA Exhibit 22

Table of Contents

PREFACE 1

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PREFACE

On March 28, 2014 the Obama Administration released a key element called for in the President's Climate Action Plan: a Strategy to Reduce Methane Emissions. The strategy summarizes the sources of methane emissions, commits to new steps to cut emissions of this potent greenhouse gas, and outlines the Administration's efforts to improve the measurement of these emissions. The strategy builds on progress to date and takes steps to further cut methane emissions from several sectors, including the oil and natural gas sector.

This technical white paper is one of those steps. The paper, along with four others, focuses on potentially significant sources of methane and volatile organic compounds (VOCs) in the oil and gas sector, covering emissions and mitigation techniques for both pollutants. The Agency is seeking input from independent experts, along with data and technical information from the public. The EPA will use these technical documents to solidify our understanding of these potentially significant sources, which will allow us to fully evaluate the range of options for cost-effectively cutting VOC and methane waste and emissions.

The white papers are available at:

www.epa.gov/airquality/oilandgas/whitepapers.html

1.0 INTRODUCTION

The oil and natural gas exploration and production industry in the U.S. is highly dynamic and growing rapidly. Consequently, the number of wells in service and the potential for greater emissions from oil and natural gas sources is also growing. There were an estimated 504,000 producing gas wells in the U.S. in 2011 (U.S. EIA, 2012a), and an estimated 536,000 producing oil wells in the U.S. in 2011 (U.S. EIA, 2012b). It is anticipated that the number of gas and oil wells will continue to increase substantially in the future because of the continued and expanding use of horizontal drilling combined with hydraulic fracturing (referred to here as simply hydraulic fracturing).

Due to the growth of this sector and the potential for increased air emissions, it is important that the U.S. Environmental Protection Agency (EPA) obtain a clear and accurate understanding of emerging data on emissions and available mitigation techniques. This paper presents the Agency's understanding of emissions and available emissions mitigation techniques from a potentially significant source of emissions in the oil and natural gas sector.

1.1 Definition of the Source

The focus of this white paper is natural gas-driven pneumatic controllers and natural gas-driven pneumatic pumps. Such pneumatic controllers and pumps are widespread in the oil and natural gas industry and emit natural gas, which contains methane and VOCs. In some applications, pneumatic controllers and pumps used in this industry may be driven by gases other than natural gas and, therefore, do not emit methane or VOCs.

1.1.1 Pneumatic Controllers

For the purposes of this white paper, a *pneumatic controller* means an automated instrument used for maintaining a process condition such as liquid level, pressure, pressure difference and temperature. Based on the source of power, two types of pneumatic controllers are defined for this paper:

- *Natural gas-driven pneumatic controller* means a pneumatic controller powered by pressurized natural gas.
- *Non-natural gas-driven pneumatic controller* means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Natural gas-driven pneumatic controllers come in a variety of designs for a variety of uses. For the purposes of this white paper, they are characterized primarily by their emissions characteristics:

- *Continuous bleed pneumatic controllers* are those with a continuous flow of pneumatic supply natural gas to the process control device (e.g., level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator. For the purposes of this paper, continuous bleed controllers are further subdivided into two types based on their bleed rate:
    - *Low bleed*, having a bleed rate of less than or equal to 6 standard cubic feet per hour (scfh).
    - *High bleed*, having a bleed rate of greater than 6 scfh.
- *Intermittent pneumatic controller* means a pneumatic controller that vents non-continuously. These natural gas-driven pneumatic controllers do not have a continuous bleed, but are actuated using pressurized natural gas.
- *Zero bleed pneumatic controller* means a pneumatic controller that does not bleed natural gas to the atmosphere. These natural gas-driven pneumatic controllers are self-contained devices that release gas to a downstream pipeline instead of to the atmosphere.

1.1.2 Pneumatic Pumps

Pneumatic pumps are devices that use gas pressure to drive a fluid by raising or reducing the pressure of the fluid by means of a positive displacement, a piston or set of rotating impellers. Pneumatic pumps are generally used at oil and natural gas production sites where electricity is not readily available (GRI/EPA, 1996d). The supply gas for these pumps can be compressed air, but most often these pumps use natural gas from the production stream (GRI/EPA, 1996e).

1.2 Background

1.2.1 Pneumatic Controllers

Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, pressure differential, and temperature. In many situations, across all segments of the oil and gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate control of a valve. In these natural gas-driven pneumatic controllers, natural gas is released with every actuation of the valve, i.e., valve movement. In some designs, natural gas is also released continuously from the valve control pilot. The rate at which the continuous release occurs is referred to as the bleed rate. Bleed rates are dependent on the design and operating characteristics of the device. Similar designs will have similar steady-state rates when operated under similar conditions. There are three basic designs of natural gas-driven pneumatic controllers: (1) continuous bleed controllers are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time; (2) intermittent controllers release gas only when they open or close a valve or as they throttle the gas flow; and (3) zero bleed controllers, which are self-contained devices that release gas to a downstream pipeline instead of to the atmosphere (EPA, 2011a).

As noted above, intermittent controllers are devices that only emit gas during actuation and do not have a continuous bleed rate. Thus, the actual amount of emissions from an intermittent controller is dependent on the amount of natural gas vented per actuation and how often it is actuated. Continuous bleed controllers also vent an additional volume of gas during actuation, in addition to the device's continuous bleed stream. Thus, actual emissions from a continuous bleed device also depend, in part, on the frequency of activation and the amount of gas vented during activation. As the name implies, zero bleed controllers are considered to emit no natural gas to the atmosphere (EPA, 2011a).

In general, intermittent controllers serve functionally different purposes than bleed controllers and, therefore, cannot replace bleed controllers in most (but not all) applications. Furthermore, zero bleed controllers are "closed loop" systems that can be used only in applications with very low pressure and therefore may not be suitable to replace continuous bleed pneumatic controllers in many applications.

Non-natural gas-driven pneumatic controllers can be used in some applications. These controllers can be mechanically operated or use sources of power other than pressurized natural gas, such as compressed "instrument air." Instrument air systems are feasible only at oil and natural gas locations that have electrical service sufficient to power an air compressor. At sites without electrical service sufficient to power an instrument air compressor, mechanical or electrically powered pneumatic controllers can be used. Non-natural gas-driven controllers do not directly release methane or VOCs, but may have secondary impacts related to generation of required electrical power (EPA, 2011a).

1.2.2 Pneumatic Pumps

There are two types of pneumatic pumps that are commonly used in the oil and natural gas sector: piston and diaphragm (GRI/EPA, 1996d). These pumps have two major components, a driver side and a motive side, which operate in the same manner but with different reciprocating mechanisms. Pressurized gas provides energy to the driver side of the pump, which operates a piston or flexible diaphragm to draw fluid into the pump. The motive side of the pump delivers the energy to the fluid being moved in order to discharge the fluid from the pump. The natural gas leaving the exhaust port of the pump is either directly discharged into the atmosphere or is recovered and used as a fuel gas or stripping gas (GRI/EPA, 1996d).

The majority of pneumatic pumps used in oil and natural gas production are used for chemical injection or glycol circulation (GRI/EPA, 1996d). Pneumatic pumps used for chemical injection are needed in oil and natural gas production to inject small amounts of chemicals to limit processing problems and protect equipment. Typical chemicals that are injected into the process include: biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers and hydrogen sulfide scavengers (GRI/EPA, 1996d). These chemicals are normally injected using pneumatic pumps at the wellhead, and into gathering lines or at production separation facilities (GRI/EPA, 1996d). Pneumatic pumps, commonly referred to as "Kimray" pumps, used for glycol circulation recover energy from the high-pressure rich glycol/gas mixture leaving the absorber and use that energy to pump the low-pressure lean glycol back into the absorber (GRI/EPA, 1996e).

1.3 Purpose of the White Paper

This white paper provides a summary of the EPA's understanding of the emissions from natural gas-driven pneumatic controllers and pumps in the oil and natural gas sector, the mitigation techniques available to reduce these emissions, the efficacy of these techniques and the prevalence of these techniques in the field. Section 2 of this document provides the EPA's understanding of emissions from pneumatic controllers and pumps, and Section 3 provides our understanding of available mitigation techniques. Section 4 summarizes the EPA's understanding based on the information presented in Sections 2 and 3, and Section 5 presents a list of charge questions for reviewers to assist the EPA with obtaining a more comprehensive understanding of pneumatic controller and pump VOC and methane emissions and emission mitigation techniques.

2.0 AVAILABLE EMISSIONS DATA AND ESTIMATES

There are a number of studies that have been published that have estimated VOC and methane emissions from pneumatic controllers and pneumatic pumps in the oil and natural gas sector. These studies have used different methodologies to estimate these emissions including the use of equipment counts and emission factors and direct measurement of emissions. Section 2.1 discusses the studies relevant to pneumatic controllers, and Section 2.2 discusses the studies relevant to pneumatic pumps. These studies are listed in Table 2-1, along with an indication of the type of information contained in the study.

Table 2-1. Summary of Major Sources of Pneumatic Controller and Pump Information

Report Name	Affiliation	Year of Report	Activity Factor	Pneumatic Controllers	Pneumatic Pumps
Methane Emissions from the Natural Gas Industry (GRI/EPA, 1996c)	Gas Research Institute / EPA	1996	Nationwide	X	X
Estimates of Methane Emissions from the U.S. Oil Industry (ICF Consulting, 1999)	EPA	1999	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014)	EPA	2014	Nationwide/ Regional	X	X
Greenhouse Gas Reporting Program (U.S. EPA, 2013)	EPA	2013	Basin	X	X
Measurements of Methane Emissions from Natural Gas Production Sites in the United States (Allen et al., 2013)	Multiple Affiliations, Academic and Private	2013	Nationwide	X	
Determining Bleed Rates for Pneumatic Devices in British Columbia (Prasino, 2013)	The Prasino Group	2013	British Columbia	X	
Air Pollutant Emissions from the Development, Production, and Processing of Marcellus Shale Natural Gas (Roy et al., 2014)	Carnegie Mellon University	2014	Regional (Marcellus Shale)	X	
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF, 2014)	ICF International	2014	Nationwide	X	X

2.1 Discussion of Data Sources for Pneumatic Controllers

This section presents and discusses pertinent studies and data sources that estimate emissions from pneumatic controllers.

2.1.1 Methane Emissions from the Natural Gas Industry (GRI/EPA, 1996c)

This report's main objective was to quantify annual methane emissions from pneumatic controllers from the natural gas production, processing, transmission, and distribution sectors. The methane emissions were determined by developing average annual emissions factors for the various types of pneumatic controllers used in each of the natural gas segments. The annual emission factors were then extrapolated to a national estimate using activity factors for each of the natural gas segments.

Production

The data used to develop emission factors for pneumatic controllers in the natural gas production sector were obtained from a study performed by the Canadian Petroleum Association (CPA)[1], manufacturers' data, measured emission rates[2], data collected from site visits, and literature data for methane composition.

The CPA study consisted of methane and VOC emission measurements from pneumatic controllers in two types of service: 19 in on/off service and 16 in throttling service.[3] The CPA study determined the average natural gas emission rate for on/off controllers was 213 standard cubic feet per day per device (scfd/device), and the average natural gas emission rate for throttling controllers was 94 scfd/device. For throttling controllers, the CPA study did not distinguish between the throttling controllers with intermittent bleed rates and throttling controllers with continuous bleed rates. In addition, only one throttling controller actuated during the emission measurement. Therefore, these measurements are lower in comparison to field measurements of similar devices in the U.S. (GRI/EPA, 1996c).

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[1] Picard, D.J., B.D. Ross, and D.W.H. Koon, *A Detailed Inventory of CH_4 and VOC Emissions from Upstream Oil and Gas Operations in Alberta*. Canadian Petroleum Association, Calgary, Alberta, 1992.
[2] Controller survey data provided by Tenneco Gas Transportation, 1994 and Chevron, 1995.
[3] Controllers in on/off service wait until a specific set point is reached before actuating (e.g., a high or low liquid level). Controllers in throttling service maintain a desired set point (e.g., pressure).

The manufacturers' data were obtained from four manufacturers of pneumatic controllers and were based on laboratory testing of new controllers. The manufacturers' noted that emissions in the field can be higher due to operating condition, age, and wear of the device. The gas consumption rates for the manufacturers' pneumatic controllers ranged from 0 to 2,150 scfd. The manufacturers noted that the emissions from these controllers in the field may be higher than the reported maximum value (GRI/EPA, 1996c).

The measured emissions data[4] were collected by connecting a flow meter to the supply line between the pressure regulator and the controller to measure the gas consumption of the controller. The duration of the test depended on the operating conditions. For steady operating conditions, one data point was measured for 15-20 minutes. For variable operating conditions, several one-hour measurements were taken. The data set contained a total of 41 measurements from a combination of continuous bleed controllers from offshore and onshore production sites and transmission stations. The average gas emissions rates for continuous bleed controllers were determined to be 872 scfd/device for onshore and offshore production sites and 1,363 scfd/device for transmission stations.

The measured emission data[5] also provided data for intermittent bleed controllers that were measured using the same techniques that were used for the continuous bleed pneumatic controllers. A total of seven measurements were performed on intermittent bleed controllers located at onshore natural gas production sites. No measurements were available for intermittent bleed controllers in the offshore or transmission segments. The average natural gas emission rate for the intermittent pneumatic controllers was determined to be 511 scfd/device.

Site visit data were collected from a total of 22 sites to determine the number of pneumatic controllers located at natural gas production sites, and to determine the fraction of these controllers that were intermittent or continuous bleed. The study determined that 65% of

[4] Controller survey data provided by Tenneco Gas Transportation, 1994 and Chevron, 1995.
[5] Controller survey data provided by Tenneco Gas Transportation, 1994 and Chevron, 1995.

the pneumatic controllers were intermittent bleed and 35% of the pneumatic controllers were continuous bleed.

The measured emission data, the CPA study emissions data, and the pneumatic controller counts were used to develop a single emission factor for a “generic” pneumatic device. For the production segment, the “generic” pneumatic controller emission factor was calculated using:

- 323 scfd/device for intermittent bleed controllers,
- 654 scfd/device for continuous bleed controllers,
- a methane content of 78.8%, and
- the ratio of intermittent bleed to continuous bleed controllers at natural gas production sites.

The “generic” emission factor was determined to be 345 scfd/device of methane for a pneumatic controller at natural gas production sites.

Transmission

The transmission “generic” emission factor was calculated using data from three types of gas-operated pneumatic controllers: continuous bleed controllers and two types of intermittent bleed controllers used to operate isolation valves[6] (isolation valves with turbine operators and isolation valves with displacement-type pneumatic/hydraulic operators). The continuous bleed emission factor was obtained from the transmission station measured emission data, which was determined to be 1,363 scfd/device. The isolation valve with displacement-type pneumatic/hydraulic operators emission factor was determined using data provided by Shafer Valve Operating Systems[7,8] and the count of the isolation valves at four sites. Using these data,

[6] Isolation valves at transmission stations are very large and are most often actuated either pneumatically or by electric motor. Isolation valve pneumatic controllers only discharge gas when they are actuated and are considered to be intermittent.

[7] Shafer Valve Operating Systems. Gas Consumption Calculation Method for Rotary Vane, Gas/Hydraulic Actuators. Technical Bulletin Data, Bulletin GC-00693. June 1993.

the average annual emission factor was determined to be 5,627 standard cubic feet per year per device (scfy/device). For turbine-operated isolation valves, the natural gas emissions were estimated using information provided by Limitorque Corporation[9] and information from two transmission sites. This information was used to calculate an emission factor of 67,599 scfy/device. The above emission factors, a methane content of 93.4% and proportions of each of these controllers at transmission sites was used to calculate a "generic" emission factor of 162,197 scfy/device of methane for pneumatic controllers at transmission stations.

Processing

The site visit information from nine natural gas processing plants found that plants used compressed air to operate the majority of pneumatic controllers at the plants. Only one of the plants used natural gas-powered continuous bleed controllers, and five had natural gas-driven pneumatic controllers for the isolation valves on the main pipeline emergency shutdown system or isolation valves used for maintenance. The same type of pneumatic controllers used in the transmission sector are used at natural gas processing sites; therefore, the same emission factors were used to calculate a facility pneumatic emission factor. Using the survey data and the transmission sector pneumatic controller emission factors, the annual methane emissions were determined to be 165 thousand standard cubic feet per facility (Mscfy/facility).

Summary

A summary of the pneumatic controller emission factors, activity factors, and annual methane emission rates estimated by this report are provided in Table 2-2 for the natural gas production, processing and transmission segments. The total methane emissions from pneumatic controllers was estimated to be 45,634 million standard cubic feet per year (MMscfy) or 861,704 metric tons (MT).

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[8] Shafer Valve Operating Systems. Gas Consumption Calculation Method for Rotary Vane, Gas/Hydraulic Actuators. Technical Bulletin Data, Bulletin GC-2-00394. March 1994.

[9] Personal correspondence with Belva Short of Limitorque Corporation, Lynchburg, VA, April 5, 1994.

Table 2-2 GRI Nationwide Pneumatic Controller Methane Emissions in the United States (1992 Base Year)

Natural gas Segment	Methane Emission Factor	Activity Factor	Annual Methane Emission Rate (MMscf/yr)	Annual Methane Emission Rate (MT)
Production	125,925 scfy/device	249,111 controllers	31,369	592,349
Processing	165,000 scfy/facility	726 facilities	120	2,262
Transmission	162,197 scfy/device	87,206 controllers	14,145	267,093
Total			45,634	861,704

2.1.2 Estimates of Methane Emissions from the U.S. Oil Industry (ICF Consulting, 1999)

ICF Consulting (ICF Consulting, 1999) prepared a report for the EPA that estimated methane emissions from crude oil production, transportation and refining, identified potential methane mitigation techniques and provided an analysis of the economics of reducing methane emissions. The report estimated that 97% of the annual methane emissions occur during crude oil production (59.1 billion cubic feet, Bcf or 1,116,000 MT) in 1995. The transportation and refining sectors generate 0.3 Bcf (5,700 MT) and 1.3 Bcf (24,500 MT) of the annual methane emissions, respectively. The annual methane emissions were estimated using methane emission factors and activity factors to calculate the annual methane emissions from the oil industry.

In the production segment, annual vented methane emissions from 13 sources account for 91% (53.8 Bcf or 1,016,000 MT) of the total 1995 methane emissions from crude oil production. Two of these sources: high bleed pneumatic controllers and low bleed pneumatic controllers account for 37% (19.9 Bcf or 376,000 MT) and 7% (3.7 Bcf or 69,900 MT) of the annual vented methane emissions, respectively.

The high bleed pneumatic controller methane emissions were calculated using an emission factor of 345 scfd (GRI/EPA, 1996c). The activity factor for high bleed pneumatic controllers was determined to be 157,581 and assumes that tank batteries with heater treaters have four pneumatic controllers (three level controllers and one pressure controller). Tank batteries without heater treaters were assumed to have three pneumatic controllers. In addition, it was assumed that 35% of the total pneumatic controllers were high bleed, which is based on the percentage of continuous bleed pneumatic controllers determined in the GRI/EPA study (GRI/EPA, 1996c).

The low bleed pneumatic controller methane emission factor was estimated to be 10% of the high bleed methane emission factor or 35 scfd.[10] The activity factor for low bleed controllers was calculated to be 292,650 controllers and was determined using the assumption that 65% of the total pneumatic controllers are intermittent bleed (GRI/EPA, 1996c), which this report assumed to be low bleed pneumatic devices.

No methane emissions from pneumatic controllers were estimated in this report for the transportation and refining segments of the oil industry.

2.1.3 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014)

The EPA leads the development of the annual Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHG Inventory). This report tracks total U.S. greenhouse gas (GHG) emissions and removals by source and by economic sector over a time series, beginning with 1990.

The U.S. submits the GHG Inventory to the United Nations Framework Convention on Climate Change (UNFCCC) as an annual reporting requirement. The GHG Inventory includes estimates of methane and carbon dioxide for natural gas systems (production through distribution) and petroleum systems (production through refining).

[10] EPA Natural Gas STAR default value for low bleed pneumatic controllers.

Table 2-3 summarizes the 2014 GHG Inventory's (published in 2014; containing emissions data for 1990-2012) estimates of 2012 national methane emissions from pneumatic controllers in the natural gas production, processing, transmission and storage segments and the petroleum production segment. Where presented in the GHG Inventory, the table includes potential emissions (i.e., emissions that would be released in the absence of controls), emission reductions and net emissions. For pneumatic controllers, the emission reductions reported to the Natural Gas STAR program are deducted from potential emission to calculate net emissions. In future years, the GHG Inventory will also account for regulatory reductions impacting emissions from pneumatic controllers that result from subpart OOOO.

Table 2-3. Summary of GHG Inventory 2012 Nationwide Emissions from Pneumatic Controllers

Industry Segment	Potential CH_4 Emissions (MT)	CH_4 Emission Reductions (MT)	Net CH_4 Emissions (MT)
Natural gas and petroleum production[a]	1,642,622	873,100	769,522
Natural gas processing	1,923	[b]	[b]
Natural gas transmission and storage	263,561	14,078	249,483

[a] In the GHG Inventory, all Natural Gas STAR reductions for pneumatic devices are removed from the natural gas systems estimate. As some of these reductions likely occur in petroleum systems, a combined number for production segment pneumatic devices in natural gas and petroleum systems is presented here.

[b] The GHG Inventory does not include a specific emission reduction for pneumatic controllers in the natural gas processing sector resulting from the Natural Gas STAR program although it is likely non-zero.

The GHG Inventory data estimates that pneumatic controller emissions are 13% of overall methane emissions from the oil and natural gas sectors. The following sections provide greater detail on the estimates given in Table 2-3.

2.1.3.1 Natural gas and petroleum production industry segment

Table 2-4 shows the 2014 GHG Inventory's estimates of 2012 methane emissions from pneumatic controllers in the natural gas and petroleum production industry segment. The table presents the population of pneumatic controllers, methane emission factors, potential methane emissions, and the estimated national total of pneumatic controllers and potential methane emissions. The natural gas production data are broken down by the Energy Information Agency's (EIA's) National Energy Modeling System (NEMS) regions. The table also presents the national total of methane emission reductions compiled from Natural Gas STAR reports and the resulting estimated national net methane emissions from pneumatic controllers.

Table 2-4. Estimated 2012 National and Regional Methane Emissions from Pneumatic Controllers in the Natural Gas and Petroleum Production Segment

NEMS Region	Population of Pneumatic Controllers[a]	CH_4 Potential Emission Factor (scfd/device)[a]	CH_4 Emissions (MT)
Potential Emissions-Natural Gas Systems			
North East	77,261	373	202,696
Midcontinent	167,589	362	426,133
Rocky Mountain	122,127	339	291,166
South West	55,095	353	136,534
West Coast	2,098	402	5,933
Gulf Coast	53,436	386	145,057
Total	477,606		1,207,519
Potential Emissions-Petroleum Systems			
High Bleed	145,179	330	336,692
Low Bleed	269,618	52	98,411
Total	414,797		435,103
Combined Natural Gas and Petroleum Systems			
Total	892,403		1,642,622
Voluntary Emission Reductions-Natural Gas and Petroleum			873,100
Net Emissions-Natural Gas and Petroleum[b]			769,522

[a] 1996 GRI/EPA report, extrapolated using ratios relating other factors for which activity data are available.
[b] In the GHG Inventory, all Natural Gas STAR reductions for pneumatic devices are removed from the natural gas systems estimate. As some of these reductions likely occur in petroleum systems, a combined number for production segment pneumatic devices in natural gas and petroleum systems is presented here.

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Recent national activity data on pneumatic controllers are not available. To calculate national emissions for these sources for the GHG Inventory, a set of industry activity data drivers was developed and used to update activity data. For the natural gas production segment, pneumatic controllers were estimated each year by applying a regional factor for the number of pneumatic controllers per well to annual regional data on gas well population. These factors ranged from 0.5 to 1.6 pneumatic controllers per well. For the petroleum production segment, pneumatic controllers were estimated each year by applying a factor for the number of pneumatic controllers per heater/treater (4), and pneumatic controller per battery without a heater/treater (3).

The basis for the GHG Inventory's potential methane emission factors for pneumatic controllers in the natural gas and petroleum production industry segment is the 1996 GRI/EPA report. The factor for natural gas systems represents a mix of the average emissions from continuous bleed and intermittent natural gas-driven pneumatic controllers in the 1996 GRI/EPA report. The region-specific factors are developed using the GRI/EPA factor and regional gas composition data. For petroleum systems, it was then assumed that 65% of pneumatic controllers in the petroleum production segment are low bleed pneumatic controllers, and 35% of controllers are high bleed. The GRI/EPA factors for low and high bleed controllers are applied to these populations

According to the GHG Inventory, the 1996 GRI/EPA report "still represents the best available [emissions] data in many cases, [but] using these emission factors alone to represent actual emissions without adjusting for emissions controls would in many cases overestimate emissions. For this reason, 'potential emissions' are calculated using the [1996 GRI/EPA report] data, and then current data on voluntary and regulatory emission reduction activities are deducted to calculate actual emissions."

In the case of pneumatic controllers in the natural gas production industry segment, the GHG Inventory reduces the calculated potential emissions using voluntary emission reductions reported by industry partners to the Natural Gas STAR Program. The reductions undergo quality assurance and quality control checks to identify errors, inconsistencies, or irregular data before being incorporated into the GHG Inventory. Future inventories are expected to reflect the subpart OOOO requirements for pneumatic controllers as they are implemented.

2.1.3.2 Natural gas processing industry segment

Table 2-5 shows the 2014 GHG Inventory's estimates of 2012 methane emissions from pneumatic controllers in the natural gas processing industry segment.

Table 2-5. Estimated 2012 National Methane Emissions from Pneumatic Controllers in the Natural Gas Processing Segment

Activity Factor	CH_4 Potential Emission Factor (scfy/plant)[b]	CH_4 Potential Emissions (MT)	CH_4 Emission Reductions (MT)	Net CH_4 Emissions (MT)
606 gas plants[a]	164,721	1,923	[c]	[c]

[a] *Oil and Gas Journal*, with available 2012 activity data.
[b] 1996 GRI/EPA report.
[c] Although voluntary Natural Gas STAR emission reductions are reported for this industry segment in the aggregate, no value is given specifically for pneumatic controllers.

The basis for the GHG Inventory's potential methane emission factors for pneumatic controllers in the natural gas processing segment is the 1996 GRI/EPA report. This potential emission factor is expressed in terms of standard cubic feet per year per processing plant (scfy/plant). The associated activity factor is the number of U.S. gas plants, which comes from the *Oil and Gas Journal*.

The GHG Inventory does not report emissions reductions specific to pneumatic controllers in this industry segment and, thus, there is no reported net emissions figure.

2.1.3.3 Natural gas transmission and storage segment

Table 2-6 shows the 2014 GHG Inventory's estimates of 2012 methane emissions from pneumatic controllers in the natural gas transmission and storage industry segment.

Table 2-6. Estimated 2012 National Methane Emissions from Pneumatic Controllers in the Natural Gas Transmission and Storage Segment

Subsegment	Activity Factor (# of controllers)	CH_4 Potential Emission Factor (scfy/device)	CH_4 Potential Emissions (MT)	CH_4 Emission Reductions (MT)	Net CH_4 Emissions (MT)
Transmission	70,827	162,197[a]	221,257		
Storage	13,542	162,197[a]	42,304		
Total	84,369		263,561	-14,078[b]	249,483

[a] 1996 GRI/EPA report.
[b] Voluntary Natural Gas STAR emission reductions are reported for all pneumatic controllers in this industry segment, not split out by transmission and storage.

The basis for the GHG Inventory's potential methane emission factors for pneumatic controllers in the natural gas transmission and storage segment is the 1996 GRI/EPA report. In this case, the potential emission factor is expressed in terms of scfy/device. The associated activity factor is the number of pneumatic controllers. For transmission, the number of pneumatic controllers is calculated based on transmission pipeline length. For storage, the number of pneumatic controllers is calculated based on number of compressor stations in the storage segment.

The 2014 GHG Inventory includes voluntary emission reductions reported by industry partners to the Natural Gas STAR Program for pneumatic controllers in the natural gas transmission and storage industry segment.

2.1.4 Greenhouse Gas Reporting Program (U.S. EPA, 2013)

In October 2013, the EPA released 2012 GHG data for Petroleum and Natural Gas Systems collected under the Greenhouse Gas Reporting Program (GHGRP). The GHGRP, which was required by Congress in the FY2008 Consolidated Appropriations Act, requires facilities to report data from large emission sources across a range of industry sectors, as well as suppliers of certain GHGs and products that would emit GHGs if released or combusted.

When reviewing this data and comparing it to other data sets or published literature, it is important to understand the GHGRP reporting requirements and the impacts of these requirements on the reported data. The GHGRP covers a subset of national emissions from Petroleum and Natural Gas Systems; a facility in the Petroleum and Natural Gas Systems source category is required to submit annual reports if total emissions are 25,000 MT of CO_2 equivalent (MT CO_2e) or more. Facilities use uniform methods prescribed by the EPA to calculate GHG emissions, such as direct measurement, engineering calculations, or emission factors derived from direct measurement. In some cases, facilities have a choice of calculation methods for an emission source.

The GHGRP addresses petroleum and natural gas systems with implementing regulations at 40 CFR part 98, subpart W. The rules define three segments of the oil and natural gas industry sector that are required to report GHG emissions from pneumatic controllers: (1) onshore petroleum and natural gas production, (2) onshore natural gas transmission compression, and (3) underground natural gas storage. Facilities calculate emissions from pneumatic controllers by determining the number of each type of controller at the facility and applying emission factors. In the petroleum and natural gas production segment, facilities must apply facility-specific gas composition factors for methane and CO_2. In the natural gas transmission and storage segments, default gas composition factors are used. Subpart W emission factors for pneumatic controllers are located at 40 CFR Part 98, subpart W, Table W-1A (Onshore Petroleum and Natural Gas Production), Table W-3 (Onshore Natural Gas Transmission Compression), and Table W-4 (Underground Natural Gas Storage). These emission factors are based on the 2009 document *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry* published by the American Petroleum Institute (API), which in turn is based on the 1996 GRI/EPA report.

Table 2-7 shows the number of reporting facilities[11] in each of the three industry segments, along with reported pneumatic controller methane emissions.

Table 2-7. Facilities and Reported Emissions from Pneumatic Controllers, 2012

Segment	Number of Reporting Facilities	Reported Methane Emissions (MT)[a]
Petroleum and NG Production	417	861,224
Transmission	330	7,582
Storage	38	4,493

[a] The reported methane MT CO2e emissions were converted to methane emissions in MT by dividing by a global warming potential (GWP) of methane (21).

2.1.5 Measurements of Methane Emissions at Natural Gas Production Sites in the United States (Allen et al., 2013)

A study completed by multiple academic institutions and consulting firms was conducted to gather methane emissions data at onshore natural gas sites in the U.S. and compare those emission estimates to the 2011 estimates reported in the 2013 GHG Inventory. The sources or operations tested included 305 pneumatic controllers located at 150 distinct natural gas production sites in four production regions (Appalachian, Gulf Coast, Midcontinent, and Rocky Mountain).

Testing was carried out using a Hi-Flow Sampler, which is a portable, battery-powered instrument designed to determine the rate of gas leakage around various pipe fittings, valve packings and compressor seals found in natural gas production, transmission, storage and processing facilities. To allow the quantity of methane to be separated out from other chemical

[11] In general, a "facility" for purposes of the GHGRP means all co-located emission sources that are commonly owned or operated. However, the GHGRP has developed a specialized facility definition for onshore production. For onshore production, the "facility" includes all emissions associated with wells owned or operated by a single company in a specific hydrocarbon-producing basin (as defined by the geologic provinces published by the American Association of Petroleum Geologists).

species, gas composition data were collected for each natural gas production site, typically provided by the site owner. The 305 sampled pneumatic controllers represented an estimated 41% of all the controllers associated with the wells that were sampled. The sampling time for each controller was not specified in the study. Table 2-8 shows the emission rates determined by the testing.

Table 2-8. Pneumatic Controller Methane Emission Rates Reported in the Allen Study

	Methane Emissions per Pneumatic Controller				
	Appalachian	Gulf Coast	Midcontinent	Rocky Mtn.	Total
Number sampled[a]	133	106	51	15	305
Emissions rate (scf methane/min/device)[b]	0.126 ± 0.043	0.268 ± 0.068	0.157 ± 0.083	0.015 ± 0.016	0.175 ± 0.034
Emissions rate (scf whole gas/min/device, based on site-specific gas composition)[b]	0.130 ± 0.044	0.289 ± 0.071	0.172 ± 0.086	0.021 ± 0.022	0.187 ± 0.036

[a] Intermittent and low bleed controllers are included in the total; no high bleed controllers were reported by companies providing controller type information
[b] Uncertainty characterizes the variability in the mean of the data set, rather than an instrumental uncertainty in a single measurement

The Allen study reports that the average whole gas emission rate was 11.2 scfh per pneumatic controller for the tested population, which consisted of a mix of intermittent and low bleed controllers. No high bleed controllers were reported by the companies that provided controller type information. The study also reports whole gas emission factors of 5.1 scfh for low bleed controllers and 17.4 scfh for intermittent controllers. These emission factors are based on measured emissions at the 24 sites where the site operators reported only low bleed controllers and the 55 sites reporting only intermittent controllers, where potential misidentification of controller type is less likely to be a confounding factor.

The study notes that there is significant geographical variability in the emissions rate from pneumatic controllers between production regions. Emissions per controller from the Gulf Coast are highest and are statistically different than emissions from controllers in the Rocky Mountain and Appalachian regions. The difference in average values is more than a factor of 10 between Rocky Mountain and Gulf Coast regions. The study provided the following discussion of these differences:

> Some of the regional differences in emissions may be explained by differences in practices for utilizing low bleed and intermittent controllers. For example, new controllers installed after February 1, 2009 in regions in Colorado that do not meet ozone standards, where most of the Rocky Mountain controllers were sampled, are required to be low bleed (or equivalent) where technically feasible (Colorado Air Regulation XVIII.C.1; XVIII.C.2; technical feasibility criterion under review as this is being written). However, observed differences in emission rates between intermittent and low bleed devices (roughly a factor of 3) are not sufficient to explain all of the regional differences. A number of additional hypotheses were examined to attempt to explain the differences in emissions. For datasets consisting entirely of intermittent or entirely of low-bleed devices, the volume of oil produced was not a good predictor of emissions. Wellhead and separator pressure were also not good predictors of emissions. The definition of low-bleed controllers may be [an] issue, however. All low bleed devices are required to have emissions below 6 scf/hr (0.1 scf/m), but there is not currently a clear definition of which specific controller designs should be classified as low bleed and reporting practices among companies can vary. Other possibilities for explaining the low-bleed emission rates observed in this work, that have not yet been investigated, but that may be pursued in follow-up work, include operating practices for the use of the controllers.

The study estimated 2011 national methane emissions from pneumatic controllers in the natural gas production industry segment at 570,000 MT (with a range of 510,000 – 812,000 MT based on the 95% confidence bounds of the emission factor) using the same number of controllers (447,379) used in the 2013 GHG Inventory for 2011. This estimate was computed using a regionally weighted emission factor of 67,400 scfy methane/device.

2.1.6 Determining Bleed Rates for Pneumatic Devices in British Columbia (Prasino Group 2013)

A study completed by the Prasino Group was conducted to determine the average bleed rate of pneumatic controllers when operating under field conditions in British Columbia (BC). Bleed rates were sampled from pneumatic controllers using a positive displacement bellows meter at upstream oil and gas facilities across a variety of producing fields in the Fort St. John, BC and surrounding areas. For this study, bleed rate was defined as “the amount of fuel gas released to the atmosphere per hour,” including both continuous bleed (where applicable) and emissions during activation. The study centered on high bleed controllers, including both continuous bleed and intermittent controllers with emissions greater than 0.17 cubic meters per hour (m$^{3/}$hr) (e.g, > 6 scfh).[12] The study aimed to identify the most common high bleed pneumatic controllers in the field and test emissions from at least 30 units of each model. In identifying controllers to test, the study used a manufacturer-supplied emission rate of 0.119 m^3/hr as a cutoff to explore whether some models identified by manufacturers as low bleed perform at that level in the field.

Field measurements were carried out with a Calscan Hawk 9000 Vent Gas Meter, which uses a positive displacement diaphragm meter that detects flow rates down to zero, and can also effectively measure any type of vent gas (methane, air, or propane). (A few sampled devices ran on air at large sites using compressed air, or propane at sour sites using compressed propane; such samples were corrected using a density ratio to equivalent natural gas emissions rates.) This device uses “a precision pressure sensor, an external temperature probe, and industry standard gas flow measurement algorithms to accurately measure the gas rates and correct for pressure and temperature differences.” The report notes that metering a device can affect the operation of the device when hooked up due to back pressure, adding that it is possible that certain controllers did not produce enough pressure when hooked up to overcome the back pressure, resulting in a

[12] This definition of “high bleed” is slightly different than the definition presented in Section 1.1.1 of this paper, because “intermittent bleed controllers” are included as “high bleed controllers” if their emissions are above the specified threshold. The definition presented in Section 1.1.1 places “intermittent bleed controllers” in their own category.

zero reading. The sample time for each controller was 30 minutes, so there was variability in the number of actuation events captured for each controller depending on operating conditions.

In addition to emission factors for individual models of pneumatic controllers, the study generated emission factors for "generic high bleed controllers" and "generic high bleed intermittent controllers." The study also included a regression analysis of the relationship between bleed rate and the pressure of the supply gas routed to the controller. Based on the analysis, the study found that the positive relationship between these parameters was strong enough to recommend use of a supply pressure coefficient to calculate the bleed rate for several controller models and for generic controllers. The generic emission factors and supply pressure coefficients are shown in Table 2-9.

Table 2-9. Generic Natural Gas Emission Factors and Supply Pressure Coefficients for High Bleed Pneumatic Controllers

Type of Pneumatic Controller	Average Bleed Rate (m^3/hr)[a]	Average Bleed Rate (scfh)[b]	Coefficient Related to Supply Pressure[c]
Generic High Bleed Controller	0.2605	9.199	0.0012
Generic High Bleed Intermittent Controller	0.2476	8.744	0.0012

[a] "Bleed rate" defined to include actuation emissions as well as continuous bleed.
[b] Calculated.
[c] Supply pressure apparently in kPa, although not clearly stated in the report.

Based on what it termed a "positive correlation," the Prasino study recommended the use of the supply pressure coefficients above for calculating emission rates for generic high bleed controllers and generic high bleed intermittent controllers. It should be noted that the coefficients of determination (R^2 values) for these supply pressure coefficients are 0.41 and 0.35 for high bleed and high bleed intermittent controllers, respectively.

2.1.7 Air Pollutant Emissions from the Development, Production, and Processing of Marcellus Shale Natural Gas (Roy et al., 2014)

A study by the Center for Atmospheric Particle Studies at Carnegie Mellon University was conducted to develop an emission inventory for the development, production, and processing of natural gas in the Marcellus Shale region for 2009 and 2020. (Note: The focus of this white paper is current emissions, therefore, the 2020 projections are not discussed further.) The inventory includes estimates for emissions of nitrogen oxides, VOC, and particulate matter less than 2.5 micrometers in diameter from major activities, including VOC emissions from pneumatic controllers associated with "wet" and "dry" gas wells. The study estimated VOC emissions from pneumatic controllers associated with Marcellus Shale natural gas wells to be on the order of 10 tons/day in 2009.

This study developed these emissions estimates by estimating the number of wet and dry wells in the region and establishing per-well emission factors for 2009. The per-well emission factors are shown in Table 2-10.

Table 2-10. Per-Well VOC Emissions from Pneumatic Controllers in 2009 (95% confidence interval)

Type of Well	VOC Emissions, 2009 (tons/producing well)
Dry Gas	0.5 (0.08 – 0.8)
Wet Gas	3.5 (2.4 – 4.4)

The per-well emission factors were based on assumptions regarding the type, number, and emission factors for pneumatic controllers associated with each natural gas well, which were drawn primarily from a 2008 ENVIRON report.[13] Table 2-11 shows these assumptions.

[13] Bar-Ilan, Amnon et al., ENVIRON International Corporation. *Recommendations for Improvement to the CENRAP States' Oil and Gas Emissions Inventories*. Prepared for the Central States Regional Air Partnership. November 13, 2008. This report also includes emission factors for positioners (15.2 scfh) and transducers

Table 2-11. Assumed Type, Number, and Emission Factors for Pneumatic Controllers Associated with Each Natural Gas Well

Type of Device	Number of Controllers	Emission Factor (scfh)[a]
Liquid Level Controller	2	31 (2009)
Pressure Controller	1	17 (2009)

[a] 2009 emission factors are from the 2008 ENVIRON report.

The emission factors from this study and the ENVIRON report are not comparable to the emission factors discussed above because they are provided for different classifications of pneumatic controllers. In addition, these emission factors differ from those discussed previously in that they are based on bleed rates provided by manufacturers rather than measured emissions.

2.1.8 Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF, 2014)

The Environmental Defense Fund (EDF) commissioned ICF International (ICF) to conduct an economic analysis of methane emission reduction opportunities from the oil and natural gas industry to identify the most cost-effective approach to reduce methane emissions from the industry. The study projects the estimated growth of methane emissions through 2018 and focuses its analysis on 22 methane emission sources in the oil and natural gas industry (referred to as the targeted emission sources). These targeted emission sources represent 80% of their projected 2018 methane emissions from onshore oil and gas industry sources. Pneumatic devices are several of the 22 emission sources that are included in the study and include: high bleed pneumatic controllers, intermittent bleed pneumatic controllers, Kimray pumps, intermittent bleed pneumatic controllers – dump valves, and chemical injection pumps. The

(13.6 scfh). The emission factors in the report "were obtained from data gathered as part of the EPA's Natural Gas STAR program." Examination of Natural Gas STAR program materials clearly shows that these emission factors were derived from the manufacturer-supplied natural gas bleed rates for high bleed pneumatic controllers listed in Appendix A to *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. The ENVIRON report also includes the number of controllers of each type associated with each gas well, said to be drawn from survey data in the CENRAP states. The numbers for liquid level controllers and pressure controllers are reflected in Table 2-15; the report found zero positioners and transducers per well.

methodology that was used for this analysis is based on the 2013 GHG Inventory and uses data from the GHGRP and the University of Texas/EDF gas production measurement study (Allen et al., 2013).

The study relied on the 2013 GHG Inventory for 1990-2011 for methane emissions data for the oil and natural gas sector. These emissions data were revised to include updated information from the GHG Inventory and the *Measurements of Methane Emissions at Natural Gas Production Sites in the United States* study (Allen et al., 2013). The revised 2011 baseline methane emissions estimate was used as the basis for projecting onshore methane emissions to 2018. (Note: The focus of this white paper is current emissions, therefore, the 2018 projections are not discussed further.)

The study used the 2013 GHG Inventory estimates for 2011 to develop new activity and emission factors for pneumatic controllers. The count of pneumatic controllers was calculated using the well counts and assuming 0.94 pneumatic controllers per well. The study did find that there are an additional 8.6 pneumatic controllers per gathering/boosting station that were not accounted for in the 2013 GHG Inventory. The study also used emission factors from subpart W, which reported pneumatic controllers in three categories: low bleed, intermittent bleed and high bleed controllers. To break out the number of pneumatic controllers in each of these categories, the emission data from subpart W were analyzed, and the study determined that the percentage of pneumatic controllers were 10% high bleed, 50% intermittent bleed and 40% low bleed. These percentages were applied to the pneumatic controller counts and the respective emission factor was used to calculate the emissions from these controllers. Intermittent pneumatic controllers were further segregated into two categories: dump valves and non-dump valve intermittent controllers. The dump valves represent intermittent controllers that do not continuously bleed and only emit during actuation. The study estimated that 75% of the total intermittent pneumatic controllers were dump valves. Based on the subpart W data and the assumptions above, the study used the following emission factors for each of the controllers: 320 Mcf/yr/device for high bleed, 120 Mcf/yr/device for non-dump intermittent, 20 Mcf/yr/device for dump intermittent and 11 Mcf/yr/device for low bleed pneumatic controllers. Using these factors, the study estimated an increase of 41% (26 Bcf or 491,000 MT) in methane emissions in comparison to the 2013 GHG Inventory.

Further information included in this study on the replacement of high bleed and intermittent bleed pneumatic controllers with low bleed pneumatic controllers, and the replacement of pneumatic pumps with electric pumps as mitigation or emission reduction techniques, methane control costs, and their estimates for the potential for VOC emissions co-control benefits from the replacement of these pneumatic controllers are presented in Section 3 of this document.

2.2 Discussion of Data Sources for Pneumatic Pumps

Many of the data sources for pneumatic pumps are the same as those for pneumatic controllers, therefore, the overall descriptions of these data sources are not repeated in this section and only the information relevant to pneumatic pumps is discussed.

2.2.1 Methane Emissions from the Natural Gas Industry (GRI/EPA, 1996c) (GRI/EPA, 1996e)

The methane emission estimates for pneumatic pumps are separated into two categories for the GRI/EPA reports; chemical injection pumps (GRI/EPA, 1996d) and gas-assisted glycol pumps (GRI/EPA, 1996f). A summary of each of these reports and the methane calculation methodologies are provided in the following sections.

2.2.1.1 Methane Emissions from the Natural Gas Industry – Chemical Injection Pumps (GRI/EPA, 1996c)

This report estimates emissions from two types of pumps that the oil and natural gas industry uses for chemical injection into process streams: piston pumps and diaphragm pumps. Four sources of information were used to develop an emission factor for chemical injection pumps: a study by the CPA[14], data collected from site visits, literature data for methane composition, and data from pump manufacturers.

The CPA study provided natural gas emissions from five diaphragm chemical injection pumps using the "bagging" method. This method involves enclosing the pump and measuring the flow rate and concentration of the natural gas emissions from the pump. The measurements from this study reported natural gas emissions ranging from 254 to 499 standard cubic feet per day per pump (scfd/pump) with an average of 334 scfd/pump.

Data from site visits included: the total number of chemical injection pumps for a particular site, number of chemical injection pumps used in natural gas production, the energy source for the pump (e.g., natural gas, instrument air, electricity), frequency of operation (e.g., pumping rate in strokes per minute), number of pumps that are active or idle, pump operation schedule, size of the unit (e.g., volume displacement of the motive chamber), manufacturer and model number of the pump, and supply gas pressure. Table 2-12 provides a summary of the site visit data. The methane emission factor in Table 2-12 was calculated using a methane composition of 78.8% (GRI/EPA, 1996d).

Table 2-12. Summary of Chemical Injection Pump Site Visit Data

Chemical Injection Pump Data	All Data		Natural Gas Industry Data	
	Piston Pumps	Diaphragm Pumps	Piston Pumps	Diaphragm Pumps
Percent of Total Pumps	49.8 ± 38%	50.2 ± 38%	4.5 ± 678%	95.5 ± 32%
Pump Actuation Rate (strokes/min)	26.32 ± 29%	13.64 ± 49%	3.57 ± 42%	14.75 ± 61%
Number of Pump Actuation Measurements	32	8	15	5
Number of Sites with	7	5	2	4

[14] Canadian Petroleum Association. A Detailed Inventory of CH_4 and VOC Emissions from Upstream Oil and Gas Operations in Alberta, March 1992.

Chemical Injection Pump Data	All Data		Natural Gas Industry Data	
	Piston Pumps	Diaphragm Pumps	Piston Pumps	Diaphragm Pumps
Pump Actuation Measurements				
Percent of Pumps Operating	44.6 ± 62%	40.0 ± 52%	77.5 ± 148%	58.0 ± 39%
Number of Sites with Pumps Operating	7	10	4	6
Methane Emissions Factor (scfd/pump)	248 ± 83%		668 ± 88%	

Manufacturers' data and the CPA data were used to determine the volume of gas released per pump stroke. This was done by using the natural gas usage data (amount of natural gas required to pump one gallon of liquid), stroke length, and stoke diameter to calculate volume of natural gas per pump stoke. For diaphragm pumps, the average natural gas usage was calculated to be 0.0719 standard cubic feet per stroke (scf/stroke). The piston pump average natural gas usage was calculated to be 0.0037 scf/stroke. These averages were then used to determine the emission factor for each of the pump types by multiplying the average frequency (strokes per day) by the operating time percentage. Note that the report uses the "all data" frequency and operating percentage to calculate the emission factor for each type of pump. The emission factor for diaphragm pumps was calculated to be 446 scfd/pump and the emission factor for piston pumps was calculated to be 48.9 scfd/pump.

The percentage of piston and diaphragm pumps and their respective emission factors were then used to calculate an average emission factor for chemical injection pumps. The average emission factor was determined to be 248 scfd/pump. The 1992 national emissions were then calculated using the average chemical injection pump emission factor (248 scfd/pump) and the activity factor for chemical injection pumps of 16,971 (GRI/EPA, 1996a). The resulting 1992 national emissions from chemical injection pumps for the natural gas production segment was calculated to be 1,536 MMscf/yr (29,008 MT).

2.2.1.2 Methane Emissions from the Natural Gas Industry – Gas-Assisted Glycol Pumps (GRI/EPA, 1996e)

For many glycol dehydrators in the natural gas industry, small gas-assisted pumps are used to circulate the glycol. These pumps use energy from the high-pressure rich glycol/gas mixture leaving the absorber to pump the low-pressure lean glycol back to the absorber. Natural gas is entrained in the rich glycol stream feeding the pump and is discharged from the pump at a lower pressure to the regenerator. If the glycol unit has a flash tank, most of the natural gas in the low-pressure stream can be recovered and used as a fuel or stripping gas. If the natural gas from the pump is used as a stripping gas, or if there is no flash tank, all of the pump exhaust gas will be vented through the regenerator's atmospheric vent stack (GRI/EPA, 1996e).

Methane emissions from these gas-assisted pumps were calculated using technical information from Kimray, a manufacturer of gas-assisted pumps. No direct measurements of pump gas usage were used in the calculations. Kimray reported that the natural gas usage ranges from 0.081 actual cubic feet per gallon of glycol pumped (acf/gal) for high-pressure pumps (>400 psig) to 0.130 acf/gal for low-pressure pumps (< 400 psig). These values convert to 3.73 standard cubic feet per gallon (scf/gal) at an operating pressure of 800 psig and 83 mole percent methane for high-pressure pumps and 2.31 scf/gal at an operating pressure of 300 psig and 83 mole percent methane for low-pressure pumps.

The gas usage rates were then converted to an amount of natural gas treated by assuming a typical high-pressure dehydrator would remove 53 pounds of water per million cubic feet of gas (lbs/MMscf), and a typical low-pressure dehydrator would remove 127 lbs/MMscf. The design glycol-to-gas ratio was assumed to be three gallons of glycol per pound of water removed and an overcirculation ratio of 2.1 was used to determine the emission factors for the pumps for the natural gas production segment. Using these factors and the fraction of dehydrators without flash tanks (0.735) and the fraction of dehydrators without combustion vent controls (0.988), the emission factor for the gas-assisted pumps in the natural gas production segment were calculated to be 904.5 standard cubic feet of methane per million standard cubic feet of natural gas treated (scf/MMscf) for high-pressure pumps, and 1342.2 scf/MMscf for low-pressure pumps. The final emission factor for methane from an average gas-assisted glycol pump was determined assuming that 80% of these pumps are high-pressure and 20% are low-pressure. The average emission factor was calculated to be 992.0 scf/MMscf and was used to estimate methane emissions from the natural gas production segment.

For natural gas processing, the study assumed that only high-pressure gas-assisted glycol pumps are used. The emission factor was calculated using the high-pressure pump gas usage (3.73 scf/gal), the design glycol-to-gas ratio (3 gal glycol/lb water), the water removal rate for a high-pressure system (53 lbs/MMcsf), an overcirculation ratio of 1.0, the fraction of dehydrators without flash tanks (0.333) and the fraction of dehydrators without combustion vent controls (0.900). These values were used to calculate a methane emission factor of 177.8 scf/MMscf for gas-assisted pumps for the natural gas processing segment. The natural gas transmission and storage segments do not use gas-assisted glycol pumps.

The 1992 national methane emissions were calculated using data from site surveys to determine the natural gas throughput of dehydrators with gas-assisted pumps. The natural gas throughput of dehydrators with gas-assisted pumps was estimated to be 11.1 trillion standard cubic feet per year (Tscf/yr) for the natural gas production segment and 0.958 Tscf/yr for the natural gas processing segment. The 1992 national methane emissions from gas-assisted pumps were calculated to be 10,962 MMscf/yr (206,989 MT) for the natural gas production segment and 170 MMscf/yr (3,215 MT) for the natural gas processing segment.

2.2.2 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014)

Table 2-13 summarizes the 2014 GHG Inventory estimates of 2012 national methane emissions from pneumatic pumps in the natural gas production and processing segments. (Note: The GHG inventory does not include estimates of emissions from pneumatic pumps in the natural gas transmission and storage segments.) The pneumatic pumps described in the GHG Inventory include: chemical injection pumps and Kimray pumps. The table includes potential emissions, emission reductions and net emissions. For pneumatic pumps, the emission reductions in this report are voluntary reductions through the Natural Gas STAR program. In future years, the GHG Inventory will also account for regulatory reductions that result from subpart OOOO.

Table 2-13. Summary of GHG Inventory 2012 Nationwide Emissions from Pneumatic Pumps

Industry Segment	Potential CH_4 Emissions (MT)	CH_4 Emission Reductions (MT)	Net CH_4 Emissions (MT)
Natural gas production	455,719	2,771	452,948
Petroleum Production	49,973	N/A	
Natural gas processing	5,011	N/A	

The 2014 GHG Inventory data estimates that pneumatic pump emissions are around 16% of overall methane emissions from the natural gas production and processing sectors.

Tables 2-14 and 2-15 show the 2014 GHG Inventory's estimates of 2012 methane emissions from chemical injection pumps and gas-assisted pumps (Kimray pumps) in the natural gas and petroleum production and processing industry segments. The tables present population of chemical injection and Kimray pumps, methane emission factors and potential methane emissions from these devices in each of the EIA's NEMS regions, and the estimated national total of chemical injection pumps, Kimray pumps and potential methane emissions. The activity factors for chemical injection pumps are based on the estimated count of chemical injection pumps in operation. For the production sector, a regional factor for pumps per well (ranging from 0.01 to 0.68) is applied to annual regional well counts to calculate chemical injection pumps each year for natural gas, and for petroleum systems it is estimated that around 20% of wells have pumps (based on 1996 GRI/EPA) and that 25% of pumps use gas. For the production sector, the activity factors for Kimray pumps are based on the total throughput of natural gas multiplied by the fraction of dehydrators using gas-driven pumps (0.9 for the production segment). For the processing segment, the activity factor for Kimray pumps is based the total processing plant throughput multiplied by the fraction of natural gas treated by dehydrators at gas plants (0.5) and then multiplied by the fraction of dehydrators that use a gas-driven pump (0.1 for the processing segment).

Table 2-14. Estimated 2012 National and Regional Methane Emissions from Chemical Injection Pumps in the Natural Gas Production Segment

NEMS Region	Population of Chemical Injection Pumps[a]	CH_4 Potential Emission Factor (scfd/device)[a]	CH_4 Emissions (MT)
Natural Gas Production			
North East	795	268	1,499
Midcontinent	15,343	260	28,045
Rocky Mountain	14,849	244	25,448
South West	2,531	253	4,508
West Coast	1,422	289	2,890
Gulf Coast	2,537	278	4,951
Total Natural Gas	37,477		67,341
Voluntary Emission Reductions			-2,771
Net Emissions-Natural Gas			64,570
Petroleum Production	28,702	248	49,973

[a] 1996 GRI/EPA report, extrapolated using ratios relating other factors for which activity data are available.

Table 2-15. Estimated 2012 National and Regional Methane Emissions from Kimray Pumps in the Natural Gas Production and Processing Segments

NEMS Region	Total Natural Gas using Kimray Pumps[a]	CH_4 Potential Emission Factor (scfd/MMscf)[a]	CH_4 Emissions (MT)
Natural Gas Production			
North East	6,487,241	1,073	134,073
Midcontinent	4,409,271	1,040	88,322
Rocky Mountain	3,404,114	975	63,934
South West	1,692,957	1,014	33,050
West Coast	85,450	1,157	1,904
Gulf Coast	3,137,482	1,110	67,095
Production Total	19,216,515		388,378
Natural Gas Processing			

All Regions	1,463,675	178	5,011
Total Potential Emissions			393,389

[a] 1996 GRI/EPA report, extrapolated using ratios relating other factors for which activity data are available.
Note: The GHG Inventory did not list any Kimray pumps in the natural gas transmission or distribution sectors.

The basis for the GHG Inventory's potential methane emission factors for pneumatic pumps in the natural gas production and processing segments is the 1996 GRI/EPA report.

The region-specific factors used in the production segment are developed using the GRI/EPA factor and regional gas composition data.

2.2.3 Greenhouse Gas Reporting Program (U.S. EPA, 2013)

The GHGRP addresses petroleum and natural gas systems with implementing regulations at 40 CFR part 98, subpart W. The rule requires facilities in the onshore petroleum and natural gas production segment to report GHG emissions from pneumatic pumps. Facilities calculate emissions from pneumatic pumps by determining the number of pneumatic pumps at the facility and applying an emission factor of 13.3 scf/hour/pump. Facilities also apply a facility-specific gas composition factor for calculating emissions. For 2012, 343 facilities in the onshore petroleum and natural gas production industry segment reported emissions from pneumatic pumps, with total methane emissions of 135,227 metric tons.

2.2.4 Determining Bleed Rates for Pneumatic Devices in British Columbia (Prasino Group 2013)

The study used data from the Canadian Association of Petroleum Producers (2008), Pacific Carbon Trust (2011), Cap-Op Energy's Distributed Energy Efficiency Project Platform (DEEPP) database to compile a list of pneumatic pumps. The study notes that the total number of pneumatic pumps is unknown and the list only comprises a subset of the total population. In total, 184 samples were taken from chemical injection pumps. From the data collected, the study determined the average bleed rate for a piston-type pneumatic pumps to be 0.5917 m^3/hr (approximately 20.9 scfh). For diaphragm-type pneumatic pumps, the bleed rate was calculated to be 1.0542 m^3/hr (approximately 37.2 scfh).

2.2.5 Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF, 2014)

The analysis developed by ICF includes an inventory of methane emissions for 2011 using data from the 2013 GHG Inventory and the GHGRP (U.S. EPA, 2013), in addition to data from the EIA and GRI.

For pneumatic chemical injection pumps in the natural gas production segment, the 2011 ICF inventory updated the count of chemical injection pumps to reflect changes made to the well counts and applied the Natural Gas STAR estimated reductions associated with pneumatic pumps. These changes resulted in a 2011 methane estimate of 3 Bcf (56,600 MT) from chemical injection pumps in the natural production segment. Kimray pumps (gas-assisted glycol pumps) were estimated to be 17 Bcf (321,000 MT).

3.0 AVAILABLE PNEUMATIC DEVICE EMISSIONS MITIGATION TECHNIQUES

The following sections describe the different available emissions mitigations techniques that the EPA is aware of for pneumatic controllers and pneumatic pumps. The primary sources of information for mitigations techniques was the EPA's Natural Gas STAR Lessons Learned documents and the ICF economic analysis (ICF, 2014).

3.1 Available Pneumatic Controller Emissions Mitigation Techniques

Several techniques to reduce emissions from pneumatic controllers have been developed over the years. Table 3-1 provides a summary of these techniques for reducing emissions from pneumatic controllers including replacing high bleed controllers with low bleed or zero bleed models, driving controllers with instrument air rather than natural gas, using non-gas-driven controllers, and enhanced maintenance.

Table 3-1. Summary of Alternative Mitigation Techniques for Pneumatic Controllers

Option	Description	Applicability	Costs	Efficacy and Prevalence
Install Zero Bleed Controller in Place of Continuous Bleed Controller (U.S. EPA, 2011a, GE Energy Services, 2012)	Zero bleed controllers are self-contained natural gas-driven devices that vent to the downstream pipeline, not the atmosphere. Provide the same functional control as continuous bleed controllers, where applicable (U.S. EPA, 2011a, GE Energy Services, 2012).	Applicable only for relatively low-pressure control valves, e.g., in gathering, metering and regulation stations, power plant and industrial feed, and city gate stations/distribution applications (U.S. EPA, 2011a).	The EPA does not have cost information on this technology.	100% emission reduction, where applicable. The EPA does not have information on the prevalence of this technology in the field, however, it is the EPA's understanding that applicability is limited.
Install Low Bleed Controller in Place of High Bleed Controller (U.S. EPA, 2006b)	Low bleed controllers provide the same functional control as a high bleed devices, while emitting less continuous bleed emissions (U.S. EPA, 2006b).	Applicability depends on the function of instrumentation for an individual device and whether the device is a level, pressure, or temperature controller. Not recommended for control of very large valves that require fast and/or precise response to process changes. These are found most frequently on large compressor discharge and bypass pressure controllers (U.S. EPA, 2006b).	Based on information from Natural Gas STAR (U.S. EPA, 2006b) and supplemental research conducted for subpart OOOO, low bleed devices cost, on average, around $165 more than high bleed versions. ICF report assumed a cost of $3,000 per replacement based on industry comments (ICF, 2014).	Estimated average reductions (U.S. EPA, 2011a): *Production segment:* 6.6 tpy methane *Transmission:* 3.7 tpy methane The EPA does not have information on the prevalence of this technology in the field.

Table 3-1. Summary of Alternative Mitigation Techniques for Pneumatic Controllers

Option	Description	Applicability	Costs	Efficacy and Prevalence
Convert to Instrument Air (U.S. EPA, 2006c)	Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. In this type of system, atmospheric air is compressed, stored in a tank, filtered and then dried for instrument use. Instrument air conversion requires additional equipment to properly compress and control the pressured air. This equipment includes a compressor, power source, air dehydrator and air storage vessel (U.S. EPA, 2006c).	Most applicable at facilities where there are a high concentration of pneumatic control valves and an operator present. Because the systems are powered by electric compressors, they require a constant source of electrical power or a backup natural gas pneumatic device (U.S. EPA, 2006c).	System costs are dependent on size of compressor, power supply needs, labor and other equipment (U.S. EPA, 2006c). A cost analysis is provided in Section 3.1.3 below.	100% emission reduction, where applicable. There are secondary emissions associated with electrical power generation. The EPA does not have information on the prevalence of this technology in the field.
Mechanical and Solar-Powered Systems in Place of Bleed Controller (U.S. EPA, 2006a, U.S. EPA, 2006b)	Mechanical controls operate using a simple design comprised of levers, hand wheels, springs and flow channels. The most common mechanical control device is the liquid-level float to the drain valve position with mechanical linkages. Electricity or small electrical motors (including solar-powered) have been used to operate valves. Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. As such, solar cells require some type of backup power or storage to ensure reliability (U.S. EPA, 2006a).	Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems are also incapable of handling larger flow fluctuations. Electric-powered valves are only reliable with a constant supply of electricity (U.S. EPA, 2006a).	Depending on supply of power, costs can range from below $1,000 to $10,000 for entire systems (U.S. EPA, 2006a).	100% emission reduction, where applicable. The EPA does not have information on the prevalence of this technology in the field.

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Table 3-1. Summary of Alternative Mitigation Techniques for Pneumatic Controllers

Option	Description	Applicability	Costs	Efficacy and Prevalence
Enhanced Maintenance (U.S. EPA, 2006a)	Instrumentation in poor condition typically bleeds 5 to 10 scfh more than representative conditions due to worn seals, gaskets, diaphragms; nozzle corrosion or wear; or loose control tube fittings. This may not impact operations but does increase emissions. Proper methods of maintaining a device are highly variable (U.S. EPA, 2006a).	Enhanced maintenance to repair and maintain pneumatic controllers periodically can reduce emissions at many controllers (U.S. EPA, 2006a).	Variable based on labor, time, and fuel required to travel to many remote locations.	Natural gas emission reductions of 5 to 10 scfh (U.S. EPA, 2006a). The EPA does not have information on the prevalence of this practice in the field.

The mitigation techniques summarized in Table 3-1 are discussed in more detail in the following sections.

3.1.1 Zero Bleed Pneumatic Controllers

Zero bleed pneumatic controllers are self-contained, “closed loop” natural gas-driven controllers that vent to the downstream pipeline rather than to the atmosphere (U.S. EPA, 2011a). These closed loop devices are considered to emit no natural gas to the atmosphere. However, they can be used only in applications with very low pressure and, therefore, may not be suitable to replace continuous bleed pneumatic controllers in many applications. Some applications where they may suitable include gathering, metering and regulation stations, power plant and industrial feed, and city gate stations/distribution (U.S. EPA, 2011a). To date, the EPA has not obtained any information on the cost of zero bleed controllers or their prevalence in the field.

3.1.2 Low Bleed Pneumatic Controllers

Description

Low bleed controllers provide similar functional control as high bleed controllers, but have lower continuous bleed emissions. It has been estimated on average that 6.6 tons of methane and 1.8 tons of VOC will be reduced annually in the production segment from installing a low bleed device in place of a high bleed device (U.S. EPA, 2011a). In the transmission segment, the average achievable reductions per device are estimated around 3.7 tons and 0.08 tons for methane and VOC, respectively (U.S. EPA, 2011a). As defined in this white paper, a low bleed controller can emit up to 6 scfh, but this is higher than the expected emissions from the typical low bleed controllers available on the current market.

Applicability

There are certain situations in which replacing and retrofitting are not feasible, such as instances where a minimal response time is needed, cases where large valves require a high bleed rate to actuate, or a safety isolation valve is involved.

Replacing high bleed pneumatic with low bleed controllers is infeasible in situations where a process condition may require a fast or precise control response so that it does not stray too far from the desired set point (U.S. EPA, 2011a). A slower-acting controller could potentially result in damage to equipment and/or become a safety issue. An example of this is on a compressor where pneumatic controllers monitor the suction and discharge pressure and actuate a recycle when one or the other is out of the specified target range. Another scenario where fast and precise control is necessary includes transient (non-steady) situations where a gas flow rate may fluctuate widely or unpredictably (U.S. EPA, 2011a). In this case, a responsive high bleed device may be required to ensure that the gas flow can be controlled in all situations. Temperature and level controllers are typically present in control situations that are not prone to fluctuate as widely or where the fluctuation can be readily and safely accommodated by the equipment. Therefore, such processes may be appropriate for control from a low bleed device, which is slower acting and less precise.

Safety concerns can limit the appropriateness of low bleed controllers in specific situations where any amount of bleeding is unacceptable. Emergency valves are often not controlled with bleeding controllers (e.g., neither low bleed nor high bleed), because it may not be acceptable to have any amount of bleeding in emergency situations (U.S. EPA, 2011a). Pneumatic controllers are designed for process control during normal operations and to keep the process in a normal operating state. If an Emergency Shut Down (ESD) or Pressure Relief Valve (PRV) actuation occurs,[15] the equipment in place for such an event is spring-loaded, or otherwise not pneumatically powered. During a safety issue or emergency, it is possible that the pneumatic

[15] ESD valves either close or open in an emergency depending on the fail safe configuration. PRVs always open in an emergency.

gas supply will be lost. For this reason, control valves are deliberately selected to either fail open or fail closed, depending on which option is the failsafe.

Costs

The costs described in this section are based on vendor research and information given in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic controllers (U.S. EPA, 2006a). As Table 3-2 indicates, the average cost for a low bleed pneumatic is $2,553, while the average cost for a high bleed is $2,338.[16] Thus, the incremental cost of installing a low bleed device instead of a high bleed device is on the order of $165 per device. (Note: The ICF report assumed a cost of $3,000 to replace an existing high bleed pneumatic controller with a low bleed pneumatic controller based on industry comments (ICF, 2014).)

Table 3-2. Cost Projections for the Representative Pneumatic Controllers[a]

Device	Minimum cost ($)	Maximum cost ($)	Average cost ($)	Low Bleed Incremental Cost ($)
High bleed controller	366	7,000	2,388	$165
Low bleed controller	524	8,852	2,553	

[a] Major pneumatic controllers vendors were surveyed for costs, emission rates and any other pertinent information that would give an accurate picture of the present industry.

Monetary savings associated with additional gas captured to the sales line were estimated based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010).[17] The representative low bleed device is estimated to emit 6.65 tons, or 319 Mcf, (using the conversion factor of 0.0208 tons methane per 1 Mcf) of methane less than the average high bleed device per year. Assuming production quality gas is 82.8% methane by volume, this equals 385.5 Mcf natural gas recovered

[16] Costs are estimated in 2008 U.S. Dollars.

[17] The average market price for natural gas in 2010 was approximately $4.16 per Mcf. This is much less compared to the average price in 2008 of $7.96 per Mcf. Due to the volatility in the value, a conservative savings of $4.00 per Mcf estimate was projected for the analysis in order to not overstate savings.

per year (EC/R, 2011). Therefore, the value of recovered natural gas from one pneumatic controller in the production segment equates to approximately $1,500. While the owner of the transmission system is generally not the owner of the natural gas, the potentially lost gas still has value. The total value of the recovered gas from one pneumatic controller in the transmission segment is $1,375 assuming a natural gas value of $4.00 per Mscf and transmission natural gas is 92.8% methane by volume (EC/R, 2011).

3.1.3 Instrument Air Systems

Description

The major components of an instrument air conversion project include the compressor, power source, dehydrator, and volume tank. The following is a description of each component as described in the Natural Gas STAR document (U.S. EPA, 2006c), *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air:*

- Compressors used for instrument air delivery are available in various types and sizes, from centrifugal (rotary screw) compressors to reciprocating piston (positive displacement) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed. A minimum amount of electrical service is required to power the compressors.
- A critical component of the instrument air control system is the power source required to operate the compressor. Because high-pressure natural gas is abundant and readily available, gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and in remote locations, however, a reliable source of

electric power can be difficult to ensure. In some instances, solar-powered battery-operated air compressors can be effective for remote locations, which reduce both methane emissions and energy consumption. Small natural gas powered fuel cells are also being developed.

- Dehydrators, or air dryers, are also an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.
- The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high-pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools, without affecting the process control functions.

Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. The use of instrument air eliminates natural gas emissions from natural gas powered pneumatic controllers. All other parts of a gas pneumatic system will operate the same way with instrument air as they do with natural gas. A diagram of a natural gas pneumatic controller is presented in Figure 3-1. A diagram of a compressed instrument air system is presented in Figure 3-2.

Applicability

The use of instrument air eliminates natural gas emissions from the natural gas-driven pneumatic controllers; however, these systems may only be used in locations with access to a sufficient and consistent supply of electrical power. Instrument air systems are also usually installed at facilities where there is a high concentration of pneumatic control valves and the presence of an operator that can ensure the system is properly functioning (U.S. EPA, 2006c).

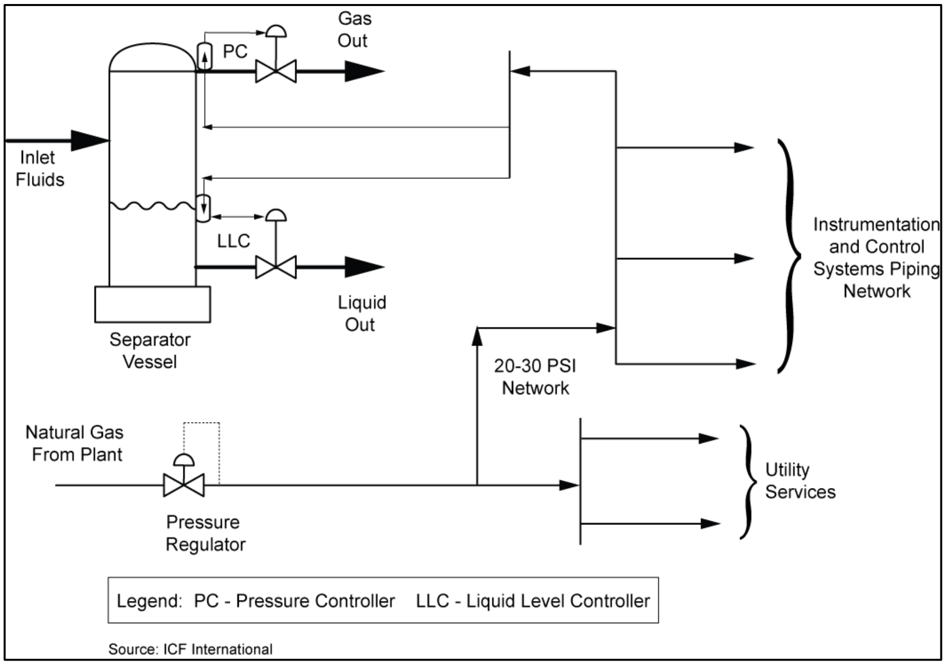

Figure 3-1 Natural Gas Pneumatic Control System

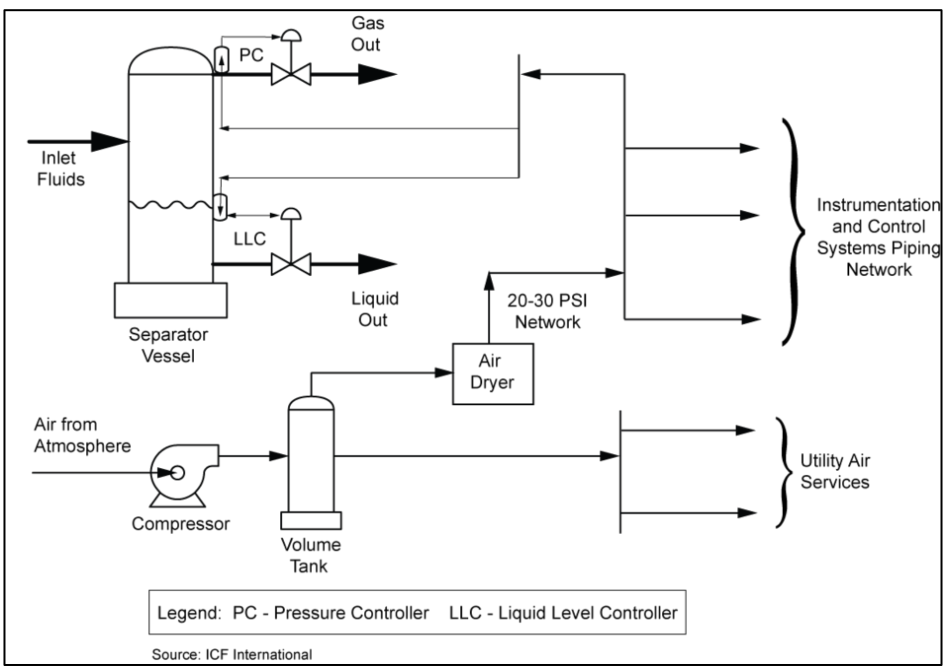

Figure 3-2. Compressed Instrument Air System

Costs

Instrument air conversion requires additional equipment to properly compress and control the pressured air. The size of the compressor will depend on the number of control loops present at a location. A control loop consists of one pneumatic controller and one control valve. The volume of compressed air supply for the pneumatic system is equivalent to the volume of gas used to run the existing instrumentation—adjusted for air losses during the drying process. The current volume of gas usage can be determined by direct metering if a meter is installed. Otherwise, an alternative rule of thumb for sizing instrument air systems is 1 cubic foot per minute (cfm) of instrument air for each control loop. As the system is powered by electric compressors, the system requires a constant source of electrical power or a backup pneumatic device. Table 3-3 outlines three different sized instrument air systems including the compressor power requirements, the flow rate provided from the compressor, and the associated number of control loops.

Table 3-3. Compressor Power Requirements and Costs for Various Sized Instrument Air Systems[a]

Compressor Power Requirements[b]			Flow Rate	Control Loops
Size of Unit	Hp	kW	(cfm)	Loops/Compressor
Small	10	13.3	30	15
Medium	30	40	125	63
Large	75	100	350	175

[a] Based on rules of thumb stated in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air.*

[b] Power is based on the operation of two compressors operating in parallel (each assumed to be operating at full capacity 50% of the year).

The primary costs associated with conversion to instrument air systems are the initial capital expenditures for installing compressors and related equipment and the operating costs for electrical energy to power the compressor motor. This equipment includes a compressor, a power source, a dehydrator and a storage vessel. It is assumed that in either an instrument air solution or a natural gas pneumatic solution, gas supply piping, control instruments, and valve actuators of the gas pneumatic system are required. The total cost, including installation and labor, of three representative sizes of compressors based on assumptions found in the Natural Gas STAR document, “Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air” are summarized in Table 3-4.

3.1.4 Mechanical and Solar-Powered Systems in Place of Bleed Controller

Description

Mechanical controls have been widely used in the natural gas and petroleum industry. They operate using a combination of levers, hand wheels, springs and flow channels with the most common mechanical control device being a liquid-level float to the drain valve position with mechanical linkages (U.S. EPA, 2006a). Another device that is increasing in use is electronic control instrumentation. Electricity or small electrical motors (including solar-powered) have been used to operate valves and therefore do not bleed natural gas into the atmosphere (U.S. EPA, 2006a). Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. As such, solar cells require some type of backup power or storage to ensure reliability.

Applicability

Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems are also incapable of handling larger flow fluctuations (U.S. EPA, 2006c). Electric-powered valves are only reliable with a constant supply of electricity. These controllers can achieve 100% reduction in emissions where applicable.

Costs

Depending on supply of power, costs can range from below $1,000 to $10,000 for entire systems (U.S. EPA, 2006a).

Table 3-4 Estimated Capital and Annual Costs of Various Sized Representative Instrument Air Systems

Instrument Air System Size	Compressor	Tank	Air Dryer	Total Capital[a]	Annualized Capital[b]	Labor Cost	Total Annual Costs[c]	Annualized Cost of Instrument Air System
Small	$3,772	$754	$2,262	$16,972	$2,416	$1,334	$8,674	$11,090
Medium	$18,855	$2,262	$6,787	$73,531	$10,469	$4,333	$26,408	$36,877
Large	$33,183	$4,525	$15,083	$135,750	$19,328	$5,999	$61,187	$80,515

[a] Total Capital includes the cost for two compressors, tank, an air dryer and installation. Installation costs are assumed to be equal to 1.5 times the cost of capital. Equipment costs were derived from the Natural Gas Star Lessons Learned document and converted to 2008 dollars from 2006 dollars using the Chemical Engineering Cost Index.

[b] The annualized cost was estimated using a 7% interest rate and 10-year equipment life.

[c] Annual Costs include the cost of electrical power as listed in Table 3-3 and labor.

3.1.5 Maintenance of Natural Gas-Driven Pneumatic Controllers

Manufacturers of pneumatic controllers indicate that emissions in the field can be higher than the reported gas consumption due to operating conditions, age, and wear of the device (U.S. EPA, 2006a). Examples of circumstances or factors that can contribute to this increase include:

- Nozzle corrosion resulting in more flow through a larger opening.
- Broken or worn diaphragms, bellows, fittings, and nozzles.
- Corrosives in the gas leading to erosion or corrosion of control loop internals.
- Improper installation.
- Lack of maintenance (maintenance includes replacement of the filter used to remove debris from the supply gas and replacement of O-rings and/or seals).
- Lack of calibration of the controller or adjustment of the distance between the flapper and nozzle.
- Foreign material lodged in the pilot seat.
- Wear in the seal seat.

Maintenance of pneumatics can correct many of these problems and can be an effective method for reducing emissions. Cleaning and tuning, in addition to repairing leaking gaskets, tubing fittings, and seals, can save 5 to 10 scfh per device. Tuning to operate over a broader range of proportional band often reduces bleed rates by as much as 10 scfh. Eliminating unnecessary valve positioners can save up to 18 scfh per device (U.S. EPA, 2006a).

However, proper methods of maintaining a device are highly variable, thus, costs are variable based on labor, time, and fuel required to travel to many remote locations.

3.2 Available Pneumatic Pump Emissions Mitigation Techniques

There are several techniques that are currently being used to reduce emissions from pneumatic pumps. Table 3-5 provides a summary of these techniques for reducing emissions from pneumatic pumps, which include chemical injection pumps and natural gas-assisted recirculation pumps.

3.2.1 Instrument Air Pump

Description

Circulation pumps in glycol dehydration processes and chemical injection pumps are often powered by pressurized natural gas at remote locations. As a result, these pumps vent natural gas to the atmosphere as part of their normal operation. To mitigate VOC and methane emissions, some companies are using instrument air to power these pumps. These companies have found that the use of instrument air increased operational efficiency, decreased maintenance and decreased costs, while eliminating emissions of methane and VOC (U.S. EPA, 2011b).

Applicability

Converting chemical injection pumps and glycol dehydration circulation pumps to instrument air can be applied to natural gas hydration operations across all gas industry sectors with excess capacity of its instrument air system. Because the systems are powered by electric compressors, they require a constant source of electrical power or a backup natural gas pneumatic device (U.S. EPA, 2011b).

Costs

The total cost to convert a natural gas pneumatic circulation pump to instrument air includes the installation of piping and an appropriate control system between the existing instrument air system and the glycol pump if the driver is independent of the circulation pump. If the driver is separated from the pump by O-rings, then the pump would need to also be replaced. The implementation capital costs are estimated to be $1,000 to $10,000, and the incremental operating costs are estimated to be $100 to $1,000 (U.S. EPA, 2011b). The potential annual

Table 3-5. Summary of Alternative Mitigation Techniques for Pneumatic Pumps

Option	Description	Applicability	Costs	Efficacy and Prevalence
Replace natural gas-assisted pump with instrument air pump (U.S. EPA, 2011b)	Circulation pumps in glycol dehydration units and chemical injection pumps are retrofitted with instrument air to drive the pumps (U.S. EPA, 2011b).	Facilities with excess capacity of instrument air or facilities that can install an air compressor system. Because the systems are powered by electric compressors, they require a constant source of electrical power or a backup natural gas pneumatic pump (U.S. EPA, 2011b).	The installation of the piping from the air compressor system to the pump accounts for the bulk of the capital cost and typically ranges from \$100 to \$1,000 (U.S. EPA, 2011b).	100% emission reduction, where applicable. The Natural Gas STAR reports typical annual methane savings to be 2,500 Mcf for glycol circulation pumps and 183 Mcf for chemical injection pumps (U.S. EPA, 2011b). The EPA does not have information on the prevalence of this technology in the field.
Replacement of natural gas-assisted pump with solar-charged direct current pump (U.S. EPA, 2011b)	In field settings, low volume natural gas pneumatic pumps can be replaced with solar-charged DC pumps (U.S. EPA, 2011b).	Low volume solar-charged pneumatic pumps are limited to approximately 5 gallons per day discharge at 1,000 psig. Large volume solar pumps are available with maximum output of 38 to 100 gallons per day at maximum injection pressures of 1,200 to 3,000 psig (U.S. EPA, 2011b).	The reporting partners for Natural Gas STAR stated a replacement cost of \$2,000 per pump, including the solar panels, storage batteries and pump (U.S. EPA, 2011b).	100% emission reduction, where applicable. The Natural Gas STAR reports typical annual methane savings to be 182.5 Mcf per chemical injection pump conversion (U.S. EPA, 2011b). The EPA does not have information on the prevalence of this technology in the field.

Option	Description	Applicability	Costs	Efficacy and Prevalence
Replacement of natural gas-assisted pump with electric pump (ICF, 2014)	In settings where a constant supply of electricity is available, natural gas pneumatic pumps can be replaced with electric pumps (ICF, 2014).	These pumps require a constant source of electricity, thus, they are typically installed at processing plants or large dehydration facilities, which are normally equipped with electricity (U.S. EPA, 2011b).	Electrical pumps are estimated to cost roughly $10,000 per pump and the annual electrical usage cost was estimated to be $2,000 per year. (ICF, 2014)	100% emission reduction, where applicable. The annual methane reduction from replacing pneumatic pumps with electrical pumps is estimated to be 5,000 Mcf (ICF, 2014). The EPA does not have information on the prevalence of this technology in the field.

natural gas savings are estimated to be 2,500 Mcf (U.S. EPA, 2011b) or $10,000 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010). For chemical injection pumps, the implementation costs are the same, but the potential annual natural gas savings are estimated to be 183 Mcf per pump conversion (U.S. EPA, 2011b) or $732 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010).

3.2.2 Solar Power Pump

Description

Solar power can be used to operate pumps located at remote sites where electricity is not available. These solar-powered pumps use electric power captured by solar panels to operate a DC-charged pump. Solar injection pumps can handle a range of throughputs and injection pressures. Low volume solar-charged DC pumps are limited to approximately 5 gallons per day discharge at 1,000 psig (U.S. EPA, 2011b). Large volume solar pumps are available with maximum output of 38 to 100 gallons per day at maximum injection pressures of 1,200 to 3,000 psig (U.S. EPA, 2011b). These pumps eliminate the methane and VOC emissions that would have resulted from the use of a pneumatic pump.

Applicability

These solar-powered pumps are generally used to replace low volume natural gas pneumatic pumps if sufficient sunlight is available to power the pumps and backup power is not required. These low volume pumps are typically used to inject methanol or corrosion inhibiters into producing wells and other field equipment. These chemical injection pumps are typically sized for 6 to 8 gallons of methanol injection per day. The large volume pumps can be used to replace gas-assisted circulation pumps for glycol dehydrators.

Costs

The Natural Gas STAR program reported the cost of replacing pneumatic pumps with solar-charged electric pumps to be approximately $2,000 per pump (U.S. EPA, 2011b). The solar panels and storage batteries are nearly maintenance free, and the solar panels have a life span of up to 15 years and the electric motors last approximately 5 years in continuous use (U.S. EPA, 2011b). The potential annual natural gas savings are estimated to be 2,500 Mcf or $10,000 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010) for recirculation pumps (U.S. EPA, 2011b). For chemical injection pumps, the implementation costs are the same, but the potential annual natural gas savings are estimated to be 183 Mcf (U.S. EPA, 2011b) or $732 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010). The ICF report estimates the cost of replacing chemical injection pneumatic pumps with solar-powered pumps to be $5,000 per pump with a natural gas savings of 180 Mcf per year (ICF, 2014) or $720 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010).

3.2.3 Electric Power Pumps

Description

Electric power pumps are used to replace natural gas-assisted pneumatic used to recirculate glycol in gas dehydrators. These pumps eliminate the methane and VOC emissions that would have resulted from the use of a pneumatic pump.

Applicability

These pumps require a constant source of electricity, thus, they are typically installed at processing plants or large dehydration facilities, which are normally equipped with electricity.

Costs

Electrical pumps are estimated to cost roughly $10,000 per pump and the annual electrical usage cost was estimated to be $2,000 per year (ICF, 2014). The annual methane reduction from replacing pneumatic pumps with electrical pumps is estimated to be 5,000 Mcf (ICF, 2014) or $20,000 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010).

4.0 SUMMARY

The EPA has used the data sources, analyses and studies discussed in this paper to form the Agency's understanding of emissions from pneumatic controllers and pumps and the emissions mitigation techniques. The following are characteristics the Agency believes are important to understanding these sources of VOC and methane emissions.

4.1 Pneumatic Controllers

- The majority of recent emissions estimates for pneumatic controllers have focused on methane emissions and not VOC emissions.
- The GHG Inventory data estimates that pneumatic controller emissions are 13% of overall methane emissions from the oil and natural gas sectors.
- Recent emission measurement studies have resulted in a wide range of methane emission factors for natural gas-driven pneumatic controllers. The studies all show that emissions can vary depending on sector (e.g., production, transmission, or storage) and the type of gas-driven pneumatic controller.
- Natural gas-driven pneumatic controllers are particularly useful in segments of the oil and natural gas industry that involve remote locations where electrical power is not available or reliable.
- Low bleed gas-driven controllers can replace high bleed gas-driven controllers in many, but not all, applications.
- Where a reliable source of electrical power is available, instrument air systems can replace natural gas-driven pneumatic controllers, and result in no methane or VOC emissions.
- Zero bleed, mechanical, and solar-powered controllers can replace continuous bleed controllers in certain applications, but are not broadly applicable to all segments of the oil and natural gas industry.

4.2 Pneumatic Pumps

- Pneumatic pumps in the oil and natural gas industry are used as chemical injection pumps and circulation pumps for glycol dehydrators. Pressure from the natural gas line is used to power these pumps and the natural gas is vented to the atmosphere.
- There are several mitigation techniques that can be used to reduce or eliminate emissions from pneumatic pumps and they include: instrument air pumps and electric pumps (both AC and DC powered).
- The 2014 GHG Inventory data estimates that pneumatic pump emissions are 16% of overall methane emissions from the natural gas production and processing sectors. The 2014 GHG Inventory estimated methane emissions from these sources to be 64,570 MT of methane for chemical injection pumps and 393,389 MT of methane for natural gas-assisted Kimray pumps. Chemical injection pumps at petroleum systems emitted 49,973 MT of methane, or around 3% of emissions from petroleum production.
- Natural gas-driven pneumatic pumps are particularly useful in segments of the oil and natural gas industry that involve remote locations where electrical power is not available or reliable.
- Where a reliable source of electrical power is available, instrument air systems are an effective replacement for natural gas-driven pneumatic pumps.

5.0 CHARGE QUESTIONS FOR REVIEWERS

1. Did this paper appropriately characterize the different studies and data sources that quantify emissions from pneumatic controllers and pneumatic pumps in the oil and gas sector?
2. Please discuss explanations for the wide range of emission rates that have been observed in direct measurement studies of pneumatic controller emissions (e.g., Allen et al., 2013 and Prasino 2013). Are these differences driven purely by the design of the monitored controllers or are there operational characteristics, such as supply pressure, that play a crucial role in determining emissions?

3. Did this paper capture the full range of technologies available to reduce emissions from pneumatic controllers and pneumatic pumps oil and gas facilities?
4. Please comment on the pros and cons of the different emission reduction technologies. Please discuss efficacy, cost and feasibility for both new and existing pneumatics.
5. Please comment on the prevalence of the different emission control technologies and the different types of pneumatics in the field. What particular activities require high bleed pneumatic controllers and how prevalent are they in the field?
6. What are the barriers to installing instrument air systems for converting natural gas-driven pneumatic pumps and pneumatic controllers to air-driven pumps and controllers?
7. Are there situations where it may be infeasible to use air driven pumps and controllers in place of natural gas-driven pumps and controllers even where it is feasible to install an instrument air system?
8. Did this paper correctly characterize the limitations of electric-powered pneumatic controllers and pneumatic pumps? Are these electric devices applicable to a broader range of the oil and gas sector than this paper suggests?
9. Are there ongoing or planned studies that will substantially improve the current understanding of VOC and methane emissions from pneumatic controllers and pneumatic pumps and available techniques for increased product recovery and emissions reductions?

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STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF:

PROPOSED NEW REGULATION
20.2.50 Oil and Gas Sector — Ozone Precursor Pollutants **No. EIB 21-27(R)**

PRE-FILED TECHNICAL TESTIMONY OF MR. BRENDAN FILBY,
A WITNESS ON BEHALF OF THE GAS COMPRESSOR ASSOCIATION

I. Introduction to My Testimony

My name is Brendan Filby. I am testifying as a technical witness on behalf of the Gas Compressor Association (The GCA) in this proceeding. My testimony supports The GCA's proposed changes to the New Mexico Environment Department's (Department) proposed regulation set out as 20.2.50.115.B(4) NMAC in the Department's proposed rule 20.2.50 NMAC (Proposed Rule). The GCA's proposed changes to the that particular part of the Proposed Rule are set forth in redline in GCA Exhibit 4, and relate to the control device inspection requirements established in the Proposed Rule.

This testimony begins with an overview of my credentials. I will then go on to discuss the Department's proposed control device inspection schedule, as set forth in the Department's Proposed Rule at 20.2.50.115.B(4) NMAC. I will then discuss The GCA's concerns with this proposed provision and describe The GCA's proposal that the Department change the regulation prior to adoption to clarify that a default monthly inspection schedule for all control devices should not apply in all circumstances, and that the rule should (1) allow for the use of tailored inspection plans for particular pieces of control equipment consistent with good air pollution control practices and (2) make it clear that, where a different inspection and maintenance schedule for a particular type of control equipment is established elsewhere in the rule, that specific inspection and maintenance schedule trumps the default inspection schedule of 20.2.50.115.B(4) NMAC. As set forth fully herein, The GCA's proposed amendments to 20.2.50.115.B(4) and 20.2.50.113.C(2) NMAC seek to clarify the Department's Proposed Rule and ensure that the requirements set forth therein will not be interpreted to require unnecessary control device inspections that could harm the performance of a particular control device and ultimately result in greater emissions.

II. Statement of My Qualifications and Relevant Experience.

My resume is attached as GCA Exhibit 24. I received a Bachelor of Science in biochemistry from the University of Waterloo in 1999. I started work in the emissions control field and the marketing of emissions control devices for engines in 2000. I have been working in the emissions control industry, with a particular focus on emissions control devices used in the oil and gas industry, for the past twenty-two years. From 2006 to 2008, I attended graduate business school while continuing my career, and earned a Master of Business Administration degree from the Beedie School of Business at Simon Fraser University in 2008. I have over twenty years of experience related to emissions controls for the engines used in the oil and gas industry.

My current title is Chief Executive Officer at DCL America, Inc. My current responsibilities include the overall operations for the DCL Technology Group operations in the United States. Prior to serving as DCL America's CEO, I held a number of positions with the company, including General Manager and Sales Manager.

DCL is a global leader in the design, manufacture, and implementation of advanced emissions control systems for stationary and mobile internal combustion engines. DCL's product offerings include catalytic converters, catalytic mufflers, engineered silencers, diesel particulate filters, and replacement catalyst elements. DCL's emissions control systems are internationally recognized as the industry standard for quality and reliability.

DCL has been designing, building, and servicing emissions control systems for the types of engines that are used in the oil and gas industry, and that are regulated by the Proposed Rule, for over 25 years. DCL is a one-stop source for the development, design, testing, and validation of emissions control systems, including catalytic converters, and is ISO 9001:2015 certified for the design, development, and manufacture of emissions control systems for internal combustion engines and industrial equipment. DCL has also established recommended inspection and maintenance procedures that it recommends for its emissions control systems to help ensure that those systems operate properly in the field for the lifetime of the equipment.

As CEO of DCL America, and through my earlier roles with the company, I have gained significant expertise relating to the design and operation of the catalytic converters used as emissions control devices on engines that serve in various functions in the oil and gas industry. I have had the opportunity to assist customers with compliance assurance monitoring (CAM) plan development and witnessed the operational outcomes of those practices. Furthermore, our Houston facility has operated a catalyst cleaning/testing system since 2015, and I have personally supervised its operation. I am familiar with the kind of inspection and maintenance that is necessary to keep catalytic converters in good working order.

III. The New Mexico Environment Department's Proposed Rule

1. Introduction to the Department's Proposed Emissions Inspection Requirements for Control Devices

The Department's Proposed Rule includes a general requirement to inspect all control devices "at least monthly to ensure proper maintenance and operation." *See* Proposed Rule, 20.2.50.115.B(4) NMAC. Unlike the general inspection requirements for equipment other than control devices, *see* Proposed Rule, 20.2.50.112.B(1) NMAC, the Proposed Rule does not provide for different inspection schedules to be established in the section of the rule that is specifically applicable to that specific type of control device. As explained in greater detail below, this "one size fits all" monthly inspection schedule does not make sense for all control devices, and in the case of catalytic converters, could risk damage of the catalyst. Steady-state engine operation is better for the longevity and performance of the catalyst, and lowers the risk from adverse combustion events (*i.e.*, backfiring) that could damage the catalyst. Engine starts and stops for monthly inspections, when the engine would otherwise be in constant operation, will increase the risk of damage to the catalyst. Moreover, increasing the number of engine starts and stops for catalyst inspections will result in additional run-time at lower exhaust temperatures, when the catalyst will not be operating at peak efficiency.

Similarly, the Proposed Rule fails to recognize the value of tailored inspection and maintenance plans, based on the inspection and maintenance schedules recommended by a manufacturer or supplier such as DCL, or those that have been developed by the owners or operators of engines and other equipment. As set forth more fully below, the Department should amend its Proposed Rule to clarify that a specific control device inspection schedule established elsewhere in the rule trumps the generic monthly inspections required by Proposed Rule 20.2.50.115.B(4) NMAC, and also allow owners or operators to rely on tailored inspection and maintenance schedules that they have developed to keep a particular piece of emissions control equipment operating properly.

2. The GCA's Concerns with the Department's Proposed Inspection Schedule for Control Devices and Proposed Amendments Thereto

The language the Department has proposed to include in the Proposed Rule at 20.2.50.115.B(4) NMAC should be amended because, as currently drafted, it establishes a "one size fits all" inspection schedule for emissions control equipment that is both unnecessary and, when applied to catalytic converters, may be counter-productive. Section 115 of the Proposed Rule applies to control devices. Subsection B of Section 115 establishes General Requirements for control devices. Proposed Rule 20.2.50.115.B(4) NMAC states:

> 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.

Elsewhere in the rule, *see* Proposed Rule 20.2.113.C(2) NMAC, the proposed rule states that catalytic converters (and AFR controllers) "shall be maintained according to manufacturer or supplier recommended maintenance schedules." However, there is nothing in the Proposed Rule that resolves the potential conflict between these two provisions – and as a manufacturer and supplier of catalytic converters, I can assure the Board that DCL's recommended inspection and maintenance schedule conflicts with the "at least monthly" inspection schedule required by Proposed Rule 20.2.50.115.B(4) NMAC.

As stated above, I have decades of experience working for a company that designs and manufactures catalytic converters that are used to improve the emissions performance from engines used in the oil and gas industry. I have reviewed the Proposed Rule. After reviewing the Proposed Rule, it is my opinion – and the opinion of others at DCL – that the monthly control device inspection requirements in the proposed rule are onerous and unnecessary for catalytic converters. DCL's maintenance and operations manuals recommend a quarterly (or every 2000 hours of operation) check of temperature and pressure differentials, and a further inspection only if those results deviate from the baseline by more than 25 percent. It is my experience, and DCL's experience, that a typical high speed natural gas-fired engine in a continuous duty application such as gas compression would require visual inspection no more frequently than every 18-24 months, unless otherwise indicated by the check of temperature and pressure differentials noted above.

Moreover, I am concerned that a requirement to conduct monthly inspections of catalytic converters could result in long-term negative impacts on catalyst. Conducting catalytic converter inspections at that frequency will require more starting and stopping of the engines. Starting and stopping an engine can increase the risk of the engine backfiring, which can harm the catalyst. DCL's catalytic converters are designed to operate with far less-frequent inspections than are required by the Proposed Rule. Monthly inspections of catalytic converters would be onerous and impose cost on the operator while providing no environmental or control device performance benefit compared to a less-frequent inspection schedule that takes into account the manufacturer's recommendations.

In order to address these concerns, The GCA proposes amending the language in the Proposed Rule to clarify that the specific language relating to catalytic converter inspections in Proposed Rule 20.2.113.C(2) NMAC trumps the default monthly inspection cycle established in Proposed Rule 20.2.50.115.B(4) NMAC. In addition, The GCA suggests that the rule language regarding control device inspections be amended to allow owners and operators to use tailored inspection and maintenance schedules that have been created by owners and operators. Allowing the use of tailored inspection and maintenance schedules will make the Department's Proposed Rule consistent with the federal rule, 40 CFR Part 63, Subpart ZZZZ, that already establishes requirements for the operations of these engines. Those tailored inspection schedules, which in my experience are based on the inspection recommendations of manufacturers like DCL and also take into account the owner or operator's experience in optimizing the operation of the control equipment in a particular operation or installation, are preferable to a default "one size fits all" inspection schedule established by rule. In particular, when it comes to catalytic converters, a regulatory requirement to conduct monthly inspections will be unnecessarily expensive and provide no benefit with regard to the emissions control performance of the catalytic converters.

IV. Conclusion

In conclusion, the requirement to perform "at least monthly" inspections of all control devices under the Department's Proposed Rule 20.2.50.115.B(4) NMAC is unnecessary and even counter-productive. For the reasons set forth above, The GCA proposes adding a provision to the general control device monitoring requirements in Proposed Rule 20.2.50.115.B(4) NMAC that will make it clear that the rule provisions specific to catalytic converters will override the default monthly inspection requirement. In addition, The GCA proposes an addition to Proposed Rule 20.2.113.C(2) NMAC to help make it clear that the requirements of paragraph 20.2.113.C(2) NMAC establish both maintenance and inspection requirements for catalytic converters. Finally, The GCA requests that the language of Proposed Rule 20.2.50.115.B(4) NMAC be changed to recognize the importance and efficacy of an owner or operator's tailored control device inspection and maintenance plans.

This concludes my direct technical testimony in this matter.

Contact

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(LinkedIn)

Top Skills

Negotiation

Sales Management

Customer Relations

Languages

French

Publications

Increased ability of transgenic plants expressing the bacterial enzyme ACC deaminase to accumulate Cd, Co, Cu, Ni, Pb, and Zn

Brendan Filby

CHIEF EXECUTIVE OFFICER: DCL AMERICA SME in the Manufacture, Launch & Sale of Emission Control Products

Spring

Summary

My eighteen-year career with DCL International and DCL America has been both interesting and rewarding.

Beginning my career with DCL International as a Key Account Manager for the US and Canada, I was successful in opening the power generation market in North America and expanding the distribution network within Texas and Oklahoma that captured market share in the oil and gas sector.

Because of my success, I was named Regional Sales Manager for the Western United States and charged with penetrating the natural gas compression and cogeneration markets. During this time, I secured the largest distributor in North America and grew our revenue by 50%.

In 2010, I was named General Manager of DCL America, and relocated to the United States to build a greenfield manufacturing facility and a US-based sales force. Over the next three years, we more than doubled our annual revenue.

Promoted to Chief Executive Officer of DCL America in 2017, I currently hold full P&L and executive leadership, serve as Vice President of Administration for ROADWARRIOR, Inc., a DCL spinoff specializing in emission control for Class 8 trucks, and provide sales leadership for two sister companies, Granite Fuel Engineering and AeriNOx.

Key leadership strengths that I bring to an organization include P&L management, startup operations, product development and launch, new market development, distribution channel management, consultative solution selling, technical sales and people development.

GCA Exhibit 24

Experience

DCL America Inc.
Chief Executive Officer
March 2017 - Present (4 years 5 months)
Houston, Texas Area

Executive leadership for a multi-million company, a staff of 50+, all strategic and tactical planning, budgeting, forecasting, lean best practices, IT, regulatory compliance, quality control/quality assurance, manufacturing and production, operations, logistics, sales and marketing strategies, and financial reporting. Continue to serve as Vice President of Administration for ROADWARRIOR Inc. Concurrent sales leadership for Granite Fuel Engineering and AeriNOx, Inc., sister companies with product synergies and a common customer base.

DCL America
General Manager
October 2010 - February 2017 (6 years 5 months)
Houston, TX

Built US-based sales force and led ground-floor development of a greenfield manufacturing facility in Houston specifically targeting the oil, gas and power generation industries. Served as Vice President of Administration for ROADWARRIOR, Inc., a DCL Group spinoff specializing in emission control for Class 8 trucks. Championed direct sales concept, initiated all sales and market training and recruited a direct sales force of nine. Coached sales team to double revenues within first three years of this cyclical business.

DCL International Inc
Regional Sales Manager
December 2005 - October 2010 (4 years 11 months)

Expanded distribution sales channels across the Western United States. Secured largest distributor in North America and managed all sales and product training. Led consultative sales calls with major OEMs and guided penetration of the US natural gas compression and cogeneration markets. Grew annual revenues by 50%.

Silex Innovations Inc
Product Manager/Consultant
November 2004 - November 2005 (1 year 1 month)

Product & Sales Consultant

GCA Exhibit 24

Retained by major customer of DCL to establish an emission control product line and to develop distribution channel strategy. Led entry into the US market and guided the development, testing and launch of new product lines.

DCL International Inc

4 years 6 months

Sales Manager

June 2004 - October 2004 (5 months)

Managed sales team selling aftermarket emission control products for off-road equipment to OEM dealerships and rental organizations across North America. Established market for catalytic mufflers and coached sales team to deliver significant annual revenue.

Key Accounts Specialist

May 2000 - June 2004 (4 years 2 months)

Marketed/sold stationary engine emission control products in the US and Canada exclusively through distribution channels. Expanded distribution network into Texas and Oklahoma that captured new opportunities in the oil and gas sector. Grew revenues in Canada four-fold over three years. Forged entry into power generation market in North America and secured record revenue in new power gen business

Education

Beedie School of Business at Simon Fraser University

Masters, Business Administration · (2006 - 2008)

University of Waterloo

BSc, Honours Co-op Biochemistry, Biotech Opt. · (1994 - 1999)

GCA Exhibit 24

STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF:

PROPOSED NEW REGULATION
20.2.50 Oil and Gas Sector — Ozone Precursor Pollutants **No. EIB 21-27(R)**

PRE-FILED TECHNICAL TESTIMONY OF MR. RANDY BARTLEY,
A WITNESS ON BEHALF OF THE GAS COMPRESSOR ASSOCIATION

I. Introduction to My Testimony

My name is Randy Bartley. I am testifying as a technical witness on behalf of The Gas Compressor Association (The GCA) in this proceeding. My testimony supports The GCA's proposed amendments to the New Mexico Environment Department's (Department) proposed regulation set out as 20.2.50.113.C(3) NMAC in the Department's proposed rule, 20.2.50 NMAC (Proposed Rule). The GCA's proposed amendments to the 20.2.50.113.C(3) NMAC are set forth in redline in GCA Exhibit 6.

This testimony begins with an overview of my credentials. I will then go on to discuss the Department's proposed emissions testing methodology, as set forth in the Department's Proposed Rule at 20.2.50.113.C(3) NMAC. I will then provide an overview of The GCA's concerns with this proposed provision and describe the GCA's proposal to amend the regulation to allow the result of the carbon monoxide (CO) emissions testing to be used to demonstrate compliance with the emissions standards for non-methane non-ethane hydrocarbons (NMNEHC). As set forth fully herein, The GCA's proposed amendments to 20.2.50.113.C(3) NMAC provide clarity to the Department's Proposed Rule and will ensure that the requirements set forth therein are achievable based on available technology.

II. Statement of My Qualifications and Relevant Experience

My resume is attached as GCA Exhibit 26. I received a Bachelor of Business Administration from the University of Oklahoma in energy management with a minor in finance in December of 2003. I have been working in the oil and gas industry for the past twenty-six years. I have over twenty years of experience related to emissions testing natural gas compressor engines.

My current title is Chief Executive Officer at B.enviroSAFE, LLC d/b/a BAIR. My current responsibilities include directing all business activities related to all industries in which BAIR operates, including oil and gas sectors, managing the operations of the company and the resources needed to meet BAIR's demand, and ensuring that BAIR's business functions focus on safety, efficiency, and regulatory compliance. As CEO of BAIR, I also oversee BAIR's accreditation with the Louisiana Environmental Laboratory Accreditation Program (LELAP), which involves bi-annual assessments on BAIR's adherence to internal Standard Operating Procedures (SOPs) and alignment to federal and state regulations and test methods via routine audits and management reviews. I have also been a member of the Source Evaluation Society (SES), since 2012. I currently serve on the ASTM D6348 re-write committee, which involves reviewing current data quality objectives set forth in current and past versions of the method while taking into consideration common industry issues in complying with the method as well as advances in technology that would allow for simplification or removal of method objectives. As set forth fully in my resume, in my twenty-six years of experience in the oil and gas industry, I have presented many times at industry related conferences and webinars regarding oil and gas related regulations, test methods and technologies available to meet the regulatory data quality objectives.

BAIR is an environmental consulting and emissions testing company. Through training and experience, I have become familiar with the emissions standards that apply to sources in the oil and gas industry, including engines, as well as the emissions testing requirements for those sources. BAIR conducts formal EPA reference method stack tests for the types of engines that are subject to the Proposed Rule. BAIR also conducts emissions testing for those engines using the type of portable analyzers that are identified in the Proposed Rule's emissions testing requirements. I am familiar with and have conducted emissions tests using both portable analyzers and traditional stack testing equipment for engines and other sources.

My experience with emissions testing and the two different test methods identified in the Proposed Rule gives me an understanding of the relative advantages and disadvantages of the different methods, including the differences in cost and convenience. More importantly, however, my experience is that both EPA reference method testing and testing with a portable analyzer represent accurate and reliable methods to determine the actual emission rates from an engine, when the testing is properly conducted.

Additionally, I am familiar with the common practice of using the test results for one pollutant to serve as a surrogate for determining the emission rate of another pollutant. State and federal testing requirements and permit conditions widely recognize the use of surrogate pollutants in emissions testing, particularly when two different pollutants' emission rates will be a function of the same control measure. For example, emissions of CO and non-methane, non-ethane hydrocarbon (NMNEHC) in the vent stream from an engine will both be reduced by good combustion practices and the engine operating properly. The same conditions that will lead to low emissions of CO in the vent stream will also lead to low emissions of NMNEHC. In those circumstances, it makes sense to allow the test results of one pollutant demonstrating compliance to serve as a surrogate for demonstrating compliance with the emission standard for the other pollutant. Passing CO results reflect good combustion practices, which will also be associated with a hydrocarbon emission rate that meets a hydrocarbon emission standard that was also set based on the engine employing good combustion practices. The use of surrogate pollutants is a way to streamline and lower the costs associated with emissions testing requirements while assuring that the tests still provide a reliable means of evaluating compliance with the applicable emission standards or permit limits.

III. The New Mexico Environment Department's Proposed Rule

1. Introduction to the Department's Proposed Emissions Monitoring and Demonstration Requirements for Engines and Turbines.

The Department's Proposed Rule includes regulations specifically applicable to portable and stationary natural gas-fired spark ignition engines, compression ignition engines, and natural gas-fired combustion turbines located at wellhead sites, tank batters, gathering and boosting sites, natural gas processing plants, and certain transmission compressor stations. *See* Proposed Rule, 20.2.50.113.A NMAC. These regulations, set forth in 20.2.50.113 NMAC, include emissions standards for various types of engines, as set out in 20.2.50.113.B NMAC, as well as monitoring requirements and methods to demonstrate emissions compliance, as set out in 20.2.50.113.C NMAC. As proposed, 20.2.50.113.C NMAC attempts to direct how compliance with emissions standards is to be demonstrated. There are a number of ambiguities and deficiencies with the Department's proposed 20.2.50.113.C NMAC regulation. As set forth more fully below, the Department should amend its proposed regulation to clarify the proposed testing methodology set forth in 20.2.50.113.C NMAC and to ensure that entities are able to demonstrate compliance based on available technology.

2. The GCA's Concerns with the Department's Proposed Emissions Monitoring and Demonstration Requirements for Engines and Turbines and Proposed Amendments Thereto.

The language the Department has proposed in the Proposed Rule at 20.2.50.113.C(3) NMAC should be amended because, as currently drafted, it is vague and requires the use of technology that cannot measure the pollutants required by the Proposed Rule. For example, 20.2.50.113.C NMAC provides that

> [f]or 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 NOx, CO, and non-methane non-ethane hydrocarbons (NMNEHC) using a portable analyzer or U.S. EPA reference method.

Similar language is found in 20.2.50.113.C(3)(b) NMAC, which states that "emissions testing utilizing a portable analyzer shall be conducted in accordance with the requirements of the current version of ASTM D6522." My concern with this language is that portable analyzers do not have the capability of measuring NMNEHC. Furthermore, the proposed language in 20.2.50.113.C(3)(b) NMAC references ASTM D6522, a test method that does not apply to the measurement of NMNEHC.

In order to address these concerns, The GCA proposes amending the language in the Proposed Rule to reflect accurate alignment of pollutants to be sampled with the correct test methods and analytical technologies. The GCA's proposed amendments, as reflected in GCA Exhibit 6, revise the proposed regulation's requirement to sample for NMNEHC to allow the measurement of CO to act as a surrogate for NMNEHC for the initial and annual tests as prescribed in the Proposed Rule. Because good combustion conditions will reduce the concentration and mass emissions of both CO and hydrocarbons in an engine's vent stream, the use of CO test results as a surrogate provide a reliable means of confirming compliance with the engine emission standards for NMNEHC. This change would align the Proposed Rule with the New Mexico Air Quality Bureau's current practices regarding emissions testing for engines, which allow test results that demonstrate compliance with CO emission limits also to demonstrate compliance with emission limits for VOCs. *See* New Mexico Air Quality Bureau, NSR & TV: *IC Engines Monitoring Protocol – Permit Template Language* at Note 3 (Version: May 23, 2016), GCA Exhibit 27.

This amendment is also necessary in order to allow the use of portable analyzers for initial and annual testing under as proposed by the 20.2.50.113.C(3) NMAC provision. Without an allowance of surrogate testing for NMNEHC, a fully equipped mobile laboratory would be needed to meet the requirement. Portable analyzers and auxiliary equipment needed to sample for nitrogen oxide (NOx) and CO using ASTM D6522 are more readily available for use than a fully equipped mobile laboratory capable of sampling for NOx, CO, and NMNEHC. Portable analyzer testing offers a reliable method for testing emission rates from these engines and demonstrating compliance with the emission standards for both NOx, CO, and NMNEHC, while reducing the costs, time, and business interruptions associated with testing performed using a fully equipped mobile laboratory.

The Department should not establish annual stack testing requirements for NMNEHC for engines as part of the new ozone precursor rules. Such a testing requirement would be unduly burdensome and costly, and the same result can be achieved through the use of portable analyzer testing and the use of CO test results as a surrogate. The Proposed Rule recognizes, in 20.2.50.13.C(3)(h) NMAC, that "Emissions 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." Depending on rule applicability, some engines may be subject to hydrocarbon stack testing requirements under federal rules. The Proposed Rule should not expand hydrocarbon stack testing requirements for engines beyond those circumstances where it is already required under federal rule, given the ability to generate reliable emissions test results for engines using less-costly portable analyzer testing and surrogate pollutants.

IV. Conclusion

The Department's proposed requirement to measure NMNEHC using portable analyzers and ASTM D6522, as set forth in Proposed Rule 20.2.50.13.C NMAC, is inconsistent with the actual measurement capabilities of portable analyzers. The GCA's proposed amendments to 20.2.50.13.C NMAC correct this regulatory error by allowing the measurement of NMNEHC, as required by the Proposed Rule, to be satisfied by the measurement of CO as a surrogate. For these reasons, The GCA's amendments to 20.2.50.13.C NMAC as set forth in GCA Exhibit 6, should be adopted.

This concludes my direct technical testimony in this matter.

Randy P. Bartley

Experience

2004-Present B.enviroSAFE, LLC dba BAIR Southlake, TX

CEO

- Oversee daily operations, finances, scheduling of jobs, marketing
- Perform various types of stack tests to determine the mass emission rates according to NSPS and NESHAP requirements (i.e 40 CFR 60 Subpart JJJJ)
- Conduct Operator Qualification training for DOT pipeline operators

2003 ExxonMobil New Orleans, LA

Landman Intern

- Projected calculated payouts of offshore drilling projects and acquisitions
- Negotiated regional pay schedule for title services
- Leased mineral rights and surface drilling rights

2002 Samson Resources Tulsa, OK

Landman Intern

- Leased mineral and surface rights for Pittsburg county drilling acquisitions
- Data entry and asset management
- Conducted title searches in several Oklahoma counties

Education

1997-2003

Energy Management (Major)

- Finance (Minor)

References

University of Oklahoma Norman, OK

References are available on request.

GCA Exhibit 26

<u>Randy Bartley</u>

Employment
B.enviroSAFE, LLC (January 2004-current)
Types of Sources Tested
Stationary Internal Combustion Engines

- 4 Stroke Rich Burn Engines
- 2 Stroke and 4 Stroke Lean Burn Engines

Stationary Gas Turbines
Gas-Fired Boilers and Process Heaters

Types of Analyzers

- Portables: ECOM A+ and J2KN, and Testo 350XL
-
- VIG Flame Ionization Model 210 Gas Chromatograph
- MKS FTIR MultiGas 2030
-

Qualifications
Proficient at demonstrating compliance for stack testing via the data collection objectives for quality assurance outlined in the following Reference Methods:

- 1-Traverse Points
- 2 and 2C - Determination of Stack Gas Velocity and Volumetric Flow Rate
- 3A-O2 (Instrumental)
- 7E-NOx (Instrumental)
- 10-Carbon Monoxide (Instrumental)
- 18-VOC by Gas Chromatograph
- 19-Dry O2 Factor
- 20-NOx from Stationary Gas Turbines
- 25A-VOC by Gas Chromatograph
- Alt 61-Single Point Testing
- Alt 87-Waiver of Stratification Tests for Engines.
- ASTM D6348 Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy.

Conducted the following types of tests in Texas, Louisiana, Oklahoma, Arkansas, Mississippi, and Kansas according to Federal and State requirements as applicable (i.e. NSPS, JJJJ, TAC 106 and TAC 117):

- Initial Compliance (Per State and Federal Regulations)
- Biennial Compliance
- Semiannual Compliance
- Quarterly Compliance

Continuing Education

- Receive quarterly training on changes to Reference Methods, State guidance for analytical purposes, and operational and safety issues pertaining to pipeline transportation of natural gas.
- Attend conferences and seminars put on by local GPAs (North Texas GPA and San Antonio GPA)
- Attended the University of Oklahoma Compressor Conference for Engine Optimization focusing on Air Fuel Ratios and Catalytic Converters
- Analytical training provided by Prism Analytical Technologies, Inc.

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NEW MEXICO AIR QUALITY BUREAU
NSR & TV: IC ENGINES MONITORING PROTOCOL –
PERMIT TEMPLATE LANGUAGE
Version: May 23, 2016

Purpose. These guidelines are intended to help permit specialists include adequate monitoring conditions into construction or operating permits in accordance with 20.2.72.210 NMAC or 20.2.70.302 NMAC. These guidelines also help ensure consistency in monitoring conditions for all permits regardless of which permit specialist is assigned the permit.

All IC engines are combustion devices subject to 20.2.61 NMAC and opacity monitoring, unless they qualify for the exemption under 20.2.61.109 NMAC (see permit template for opacity language).

NOTE: If the affected unit is subject to 40 CFR 64, CAM Rule, the AQB standard conditions may not apply.

[NOTE: Each permit writer shall review, select, and adjust the requirements below according to the specific facility circumstances.]

NOTE: EXTERRAN – Engine Integrated Control System (EICS): It is important that the permit identify that this particular control device is installed on an engine so that an enforcement inspector knows to check if the control device is installed. This is an engine emissions control device that will automatically shut down an engine if emission limits are exceeded. The department has determined that this control device is part of the engine's "physical and operational design" with regard to the definitions of PER and PTE as applied to permitting, not as applied to NSPS/NESHAP. We may adjust the monitoring requirements for engines with this control device once we have experience in verifying that the control system performs as represented. For more information, see the presentation in aurora at: P:\AQB-Permits-Section\NSR-TV-Common\Permitting-Guidance-Documents\Engines\Exterran Engine Integrated Control System.

Engines

A. Maintenance and Repair Monitoring (Unit(s) X, Y, and Z)

Requirement: Compliance with the allowable emission limits in Table 106.A shall be demonstrated by properly maintaining and repairing the units.
Monitoring: Maintenance and repair shall meet the minimum manufacturer's or permittee's recommended maintenance schedule. Activities that involve maintenance, adjustment, replacement, or repair of functional components with the potential to affect the operation of an emission unit shall be documented as they occur for the following events: (1) Routine maintenance that takes a unit out of service for more than two hours during any twenty-four hour period. (2) Unscheduled repairs that require a unit to be taken out of service for more than two hours in any twenty-four hour period.
Recordkeeping: The permittee shall maintain records in accordance with Section B109,

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including records of maintenance and repairs activities and a copy of the manufacturer's or permittee's recommended maintenance schedule.
Reporting: The permittee shall report in accordance with Section B110.

[Periodic Testing: Condition may be used for multiple scenarios; adjust as necessary and refer to flow diagram. For example, quarterly testing is required for units with controls and annual testing is required for uncontrolled units with total facility emissions ≥ 95 tpy for any pollutant.]

B. Periodic Emissions Testing (Unit(s) X, Y, and Z)

<table>
<tr><td>Requirement: Compliance with the allowable emission limits in Table 106.A shall be demonstrated by completing periodic emission tests during the monitoring period. For TV Permits add (NSR XXXX-MX, Condition AXXX.B and revised)</td></tr>
<tr><td>Monitoring: The permittee shall test using a portable analyzer or EPA Reference Methods subject to the requirements and limitations of Section B108, General Monitoring Requirements. Emission testing is required for NOx and CO [change reference to pollutants as necessary] and shall be carried out as described below.
[If the unit has VOC emission limits, include the following.]
Test results that demonstrate compliance with the CO emission limits shall also be considered to demonstrate compliance with the VOC emission limits.

For units with g/hp-hr emission limits, in addition to the requirements stated in Section B108, the engine load shall be calculated by using the following equation:

$$\text{Load(Hp)} = \frac{\text{Fuel consumption (scfh)} \times \text{Measured fuel heating value (LHV btu/scf)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$
(1) The testing shall be conducted as follows:
a. Testing frequency shall be once per [quarter or year]
b. The monitoring period is defined as [a calendar quarter, a calendar year], or [a custom schedule requested by the permittee].

(2) The first test shall occur within the first monitoring period occurring after permit issuance. [or if testing was already required by the previous permit, use this instead:] The tests shall continue based on the existing testing schedule.

(3) All subsequent monitoring shall occur in each succeeding monitoring period. No two monitoring events shall occur closer together in time than 25% of a monitoring period.
(4) The permittee shall follow the General Testing Procedures of Section B111. [add #5 if subject to testing in NSPS JJJJ/IIII or NESHAP ZZZZ] (5) Performance testing required by 40 CFR 60, Subpart JJJJ or IIII or 40 CFR 63, Subpart ZZZZ may be used to satisfy these periodic testing requirements if they meet the requirements of this condition and are completed during the specified monitoring period.</td></tr>
<tr><td>Recordkeeping: The permittee shall maintain records in accordance with Section B109, B110, and B111.</td></tr>
<tr><td>Reporting: The permittee shall report in accordance with Section B109, B110, and B111.</td></tr>
</table>

[If C&E has approved an exemption for 30-day notification then replace (4) above with this:] (4) Follow the General Testing Procedures of Section B111. Due to the unique operation of this facility as a "peaking station", the Department exempts the permittee from the 30-day notification stated in General Condition B111.D(1). The permittee shall notify the department as soon as possible prior to the test.**]** **This was done in Permits P151R2, P155R2, P153R2M1, P154R3 for TWP.**

[Initial Compliance Test: TV permits shall determine if the required test has been completed or if the requirement must be brought forward.]

C. Initial Compliance Test (Unit(s) X, Y, and Z)

Requirement: Compliance with the allowable emission limits in Table 106.A shall be demonstrated by performing an initial compliance test.
Monitoring: The permittee shall perform an initial compliance test in accordance with the General Testing Requirements of Section B111. Emission testing is required for NOx and CO. [change reference to pollutants as necessary]. [If the unit has VOC emission limits, include the following.] Test results that demonstrate compliance with the CO emission limits shall also be considered to demonstrate compliance with the VOC emission limits. The monitoring exemptions of Section B108 do not apply to this requirement. [TV: Add additional requirements from NSR Permit such as timeframe] For units with g/hp-hr emission limits, the engine load shall be calculated by using the following equation: Load(Hp) = $\frac{\text{Fuel consumption (scfh) x Measured fuel heating value (LHV btu/scf)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$
Recordkeeping: The permittee shall maintain records in accordance with the applicable Sections in B109, B110, and B111.
Reporting: The permittee shall report in accordance with the applicable Sections in B109, B110, and B111.

[If the engine has a control device, include an operational requirement. Examples are provided below. Adjust as necessary for your particular situation. Do not list control device efficiencies in the requirement.]

D. Catalytic Converter Operation (Unit(s) X, Y, and Z)

Requirement: [Include and revise requirement(s) as necessary]. (1) The unit(s) shall be equipped and operated with an oxidation catalytic converter to control CO, VOC, and HAP emissions. Engines equipped with oxidation catalysts are not required to operate with an AFR. **(Note, this last sentence should not be included if there is an add-on AFR.)** (2) The unit(s) shall be equipped and operated with a non-selective catalytic converter to control NOx, CO, and VOC emissions. These units shall also be equipped with an AFR controlling

device, or similar device that performs the same function of maintaining an appropriate air-fuel ratio. The permittee shall maintain the units according to manufacturer's or supplier's recommended maintenance, including replacement of oxygen sensor as necessary for oxygen-based controllers.
Monitoring: The unit(s) shall be operated with the catalytic converter, which includes catalyst maintenance periods. During periods of catalyst maintenance, the permittee shall either (1) shut down the engine(s); or (2) replace the catalyst with a functionally equivalent spare to allow the engine to remain in operation.
Recordkeeping: The permittee shall maintain records in accordance with Section B109.
Reporting: The permittee shall report in accordance with Section B110.

E. Air Fuel Ratio Operation (Unit(s) X, Y, and Z) [AFR only - add on device, not integral to unit]

Requirement: [Include and revise requirement(s) as necessary]. The unit(s) shall be equipped and operated with an AFR controlling device, or similar device that performs the same function of maintaining an appropriate air-fuel ratio. The permittee shall demonstrate that the manufacturer's or supplier's recommended maintenance is performed, including replacement of oxygen sensor as necessary for oxygen-based controllers.
Monitoring: The unit(s) shall be operated with the AFR, which includes maintenance periods. During periods of AFR maintenance, the permittee shall either (1) shut down the engine(s); or (2) replace the AFR with a functionally equivalent spare to allow the engine to remain in operation.
Recordkeeping: The permittee shall maintain records in accordance with Section B109, including a records of maintenance performed on AFR controllers and the manufacturer's or suppliers' recommended maintenance schedules for AFR Controllers.
Reporting: The permittee shall report in accordance with Section B110.

[Not applicable if engine is authorized to operate continuously – 8760 hours per year]

F. Hours of Operation (Unit(s) X, Y, and Z)

Requirement: To ensure compliance with allowable emission limits in Table 106.A, [insert requirement, for example only two of the three engines shall be operated at any one time].
Monitoring: The permittee shall monitor the dates and hours of operation for the units.
Recordkeeping: The permittee shall record the hours of operation daily, shall calculate and record the rolling 12-month total hours of operation, and shall meet the recordkeeping requirements in Section B109.
Reporting: The permittee shall report in accordance with Section B110.

G. Engine RPM (Unit(s) X, Y, and Z)

Requirement: [Insert operational requirement, for example] The unit shall be attached to a

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[insert make/model] compressor that physically limits the engine speed to XXX RPM.
Monitoring: Once each 12 months, the permittee shall verify that the unit is attached to the make and model of the compressor specified above.
Recordkeeping: The permittee shall maintain records of the annual monitoring and maintain manufacturer's documentation on file that shows the make, model, and maximum design speed of the compressor attached to the unit. The permittee shall maintain records in accordance with Section B109.
Reporting: The permittee shall report in accordance with Section B110.

H. RPM governor or RPM limit switch (Unit(s) X, Y, and Z)

Requirement: The permittee shall install and operate an RPM governor or RPM limit switch, each with a tamper resistant seal.
Monitoring: The permittee shall check the proper function of the governor or limit switch every 12 months.
Recordkeeping: The permittee shall maintain records of the annual monitoring and documentation of the RPM governor or limit switch with seal. The permittee shall maintain records in accordance with Section B109.
Reporting: The permittee shall report in accordance with Section B110.

I. Fuel Flow Rate (Unit(s) X, Y, and Z)

Requirement: [Add Operational Req.]
Monitoring: The permittee shall record the fuel flow/consumption for each unit (or for group of units if not available for each unit) once every 24 hours.
Recordkeeping: Each month, the permittee shall calculate and record the average fuel flow rate. The permittee shall maintain records in accordance with Section B109.
Reporting: The permittee shall report in accordance with Section B110.

[Fuel analysis is not required for facilities that certify the use of natural gas in the permit application unless HAPs are an issue. Fuel Analysis may be required for facilities that use field natural gas.]

J. Fuel Content (Unit(s) X, Y, and Z)

Requirement: The permittee shall perform a fuel analysis at least every six months by methods acceptable to NMED.
Monitoring: At a minimum, this analysis or test method shall include H_2S, moisture, VOC, and a thermal heating value in BTU for the fuel.
Recordkeeping: The permittee shall maintain records in accordance with Section B109.
Reporting: The permittee shall report in accordance with Section B110.

K. 40 CFR 60, Subpart JJJJ (Unit(s) X, Y, and Z) **[already installed units or when applicability is known]** [**Note for SoB:** Engines with Exterran EICS are considered non-certified engines (see 40 CFR 60.4243)]

Requirement: The unit(s) is/are subject to 40 CFR 60, Subparts A and JJJJ and shall comply with the notification requirements in Subpart A and the specific requirements of Subpart JJJJ.
Monitoring: The permittee shall comply with all applicable monitoring requirements in 40 CFR 60, Subpart A and Subpart JJJJ, including but not limited to 60.4243.
Recordkeeping: The permittee shall comply with all applicable recordkeeping requirements in 40 CFR 60, Subpart A and Subpart JJJJ, including but not limited to 60.4245.
Reporting: The permittee shall comply with all applicable reporting requirements in 40 CFR 60, Subpart A and Subpart JJJJ, including but not limited to 60.4245.

L. 40 CFR 60, Subpart JJJJ (Unit(s) X, Y, and Z) [To be installed units] [**Note for SoB:** Engines with Exterran EICS are considered non-certified engines (see 40 CFR 60.4243)]

Requirement: The unit(s) will be subject to 40 CFR 60, Subparts A and JJJJ if the unit is constructed (ordered) and manufactured after the applicability dates in 40 CFR 60.4230 and the permittee shall comply with the notification requirements in Subpart A and the specific requirements of Subpart JJJJ.
Monitoring: The permittee shall comply with all applicable monitoring requirements in 40 CFR 60, Subpart A and Subpart JJJJ, including but not limited to 60.4243.
Recordkeeping: The permittee shall comply with all applicable recordkeeping requirements in 40 CFR 60, Subpart A and Subpart JJJJ, including but not limited to 60.4245.
Reporting: The permittee shall comply with all applicable reporting requirements in 40 CFR 60, Subpart A and Subpart JJJJ, including but not limited to 60.4245.

Note Regarding 40 CFR 63, Subpart ZZZZ, engines with no applicable requirements.
For an engine that is subject to 40 CFR 63, Subpart ZZZZ at §§63.6585 and 6590(a), but does not have to meet the requirements of this subpart and of subpart A of this part, including initial notification (see §63.6590(b)(3)), and there are no applicable requirements in the NSR permit (e.g the unit is an emergency standby generator and NSR exempt per 20.2.72.202.B(3) NMAC or a fire pump engine and NSR exempt per 20.2.72.202.A(4) NMAC), be sure to include its NESHAP applicability determination in the Statement of Basis, but do not list the unit in Table 103-Applicable Regulations, do not include the generic Quad Z condition, and do not include any other Quad Z requirements in the permit. Initial notification as required in 63.6590(b)(1) and (b)(2) is considered an applicable requirement and therefore the unit should be included in the permit. Also, if the unit is meeting the requirements of Quad Z by meeting NSPS IIII or JJJJ (see §63.6590(c)), then the permit should list the unit in Table 103 and include the generic Quad Z condition.

Engines with no applicable requirements are Title V insignificant.

This guidance is based on the regulations as of March 25, 2013. (Note revised 2-03-15).

"40 CFR, 63.6585 You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand."

"§ 63.6590 What parts of my plant does this subpart cover?
(b) Stationary RICE subject to limited requirements.
(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:"

M. 40 CFR 63, Subpart ZZZZ (Unit(s) X, Y, and Z) [already installed units or when applicability is known]

Requirement: The unit(s) is/are subject to 40 CFR 63, Subpart ZZZZ and the permittee shall comply with all applicable requirements of Subpart A and Subpart ZZZZ.
Monitoring: The permittee shall comply with all applicable monitoring requirements of 40 CFR 63, Subpart A and Subpart ZZZZ.
Recordkeeping: The permittee shall comply with all applicable recordkeeping requirements of 40 CFR 63, Subpart A and Subpart ZZZZ, including but not limited to 63.6655 and 63.10.
Reporting: The permittee shall comply with all applicable reporting requirements of 40 CFR 63, Subpart A and ZZZZ, including but not limited to 63.6645, 63.6650, 63.9, and 63.10.

N. 40 CFR 63, Subpart ZZZZ (Unit(s) X, Y, and Z) [To be installed units]

Requirement: The unit(s) will be subject to 40 CFR 63, Subparts A and ZZZZ if they meet the applicability criteria in 40 CFR 63.6590. The permittee shall comply with any applicable notification requirements in Subpart A and any specific requirements of Subpart ZZZZ.
Monitoring: The permittee shall comply with all applicable monitoring requirements of 40 CFR 63, Subpart A and Subpart ZZZZ.
Recordkeeping: The permittee shall comply with all applicable recordkeeping requirements of 40 CFR 63, Subpart A and Subpart ZZZZ, including but not limited to 63.6655 and 63.10.
Reporting: The permittee shall comply with all applicable reporting requirements of 40 CFR 63, Subpart A and ZZZZ, including but not limited to 63.6645, 63.6650, 63.9, and 63.10.

O. 40 CFR 64, CAM (Unit(s) X, Y, and Z) [TV permits only. When an IC Engine uses a control device and uncontrolled emissions are greater than 100 tpy]

Requirement: Compliance Assurance Monitoring (CAM) contained in 40 CFR 64 applies to this facility, and the permittee shall meet the requirements of the provisions contained in Subpart 3, 7, 9(a), and 9(b).
Monitoring: The permittee shall monitor exhaust gas temperature and percent oxygen [update to match parameters listed in the CAM Plan] concentration of the gas at the catalyst inlet pursuant to 40 CFR 64.3, and continue the monitoring operation pursuant to 40 CFR 64.7. The

frequency of data collection shall be at least once every 24 hours per 40 CFR 64.3(b)(4)(iii).
Recordkeeping: The permittee shall comply with the recordkeeping requirements of 40 CFR 64.9(b).
Reporting: The permittee shall submit monitoring reports to the Department per 40 CFR 64.9(a).

P. 40 CFR 60, Subpart IIII (Unit(s) X, Y, and Z) **[diesel engines]**

Requirement: The unit is subject to 40 CFR 60, Subparts A and IIII and shall comply with the notification requirements in Subpart A and the specific requirements of Subpart IIII.
Monitoring: The permittee shall comply with all applicable monitoring requirements in 40 CFR 60, Subpart A and Subpart IIII, including but not limited to 60.4211.
Recordkeeping: The permittee shall comply with all applicable recordkeeping requirements in 40 CFR 60, Subpart A and Subpart IIII, including but not limited to 60.4214.
Reporting: The permittee shall comply with all applicable reporting requirements in 40 CFR 60, Subpart A and Subpart IIII, including but not limited to 60.4214.

BACKGROUND INFORMATION
(Not for inclusion in permit)

NOTES

Note 1: We will not apply monitoring to IC engines that qualify for an exemption under 20.2.72.202 NMAC or 20.2.70 NMAC List of Insignificant Activities.

Note 2: For any monitoring, an emission limit or standard must be identified somewhere in the permit. For example, fuel usage should be compared to the appropriate calculated maximum; rpm should be compared to the value that limits horsepower.

Note 3: Periodic Emissions Testing: "Test results that demonstrate compliance with the CO emission limits shall also be considered to demonstrate compliance with the VOC emission limits." The rationale for this statement is that the portable analyzers do not speciate VOC compounds and the cost of a separate EPA method test is significant; therefore, AQB relies on CO monitoring to demonstrate compliance with VOC limits. Taking into account that the manufacturer tests the equipment and specifies the expected NOx, CO, and VOC emissions for a unit operating properly, as well as basic principles of combustion chemistry, if an engine test demonstrates that CO concentration fall within the emission limits, then VOC also falls within the emission limits, and the engine is performing as represented in the application.

MONITORING GUIDANCE

1. Opacity must be measured for each engine to show compliance with 20.2.61 NMAC. Use of natural gas will constitute compliance without measurements if such fuel is identified in the application. Engines subject to 20.2.37 NMAC particulate matter requirements are exempt from 20.2.61 NMAC.

2. Annual Emissions Testing by portable analyzer is required for uncontrolled IC engines with emissions greater than 1 tpy and facility allowable emission limits greater than 95 tons per year.

3. Quarterly Emissions Testing by portable analyzer is required for IC engines which have control equipment (AFR, catalytic converter, etc.) installed for the purpose of limiting emission rates or for IC engines operated at crossover (equal NO_x and CO emissions) with an AFR.

4. Fuel Usage Recordkeeping used to be required in the 2001 Engine monitoring protocol and Supplemental Guidance to demonstrate compliance with a physical constraint (e.g. RPM limiting device) on and engine's capacity. Currently, the AQB only requires an RPM limiting device or the use of Governor with Seals to demonstrate that emissions are limited using deration schemes. We no longer use the 2001 Supplemental Guidance but this document can still be found in the monitoring protocol archives.

5. Fuel Analysis is required when HAPs are an issue for any IC engine, or for fugitive emission sources. Fuel Analysis may also be required for facilities that use field natural gas.

TESTING GUIDANCE

See EPA's Memorandum titled Issuance of the Clean Air Act National Stack Testing Guidance dated February 2, 2004 for additional guidance.

For initial compliance testing:

1. All emission units (100%) above 180 hp shall be tested.
2. All emission units shall be tested by EPA Method if located within a sensitive area. Sensitive areas are defined as 1) within a non-attainment area, 2) within Areas Where Streamlined Permits Are Prohibited, or 3) a source for which the emissions exceed 80% of the NAAQS, not including background concentrations from other facilities. See Modeling Guidelines Document for these areas available at http://www.nmenv.state.nm.us/aqb/modeling/modelingpubs.html.
3. All emission units shall be tested unless the units are (1) identical; (2) located at the same facility; (3) operated and maintained in a similar manner; (4) the permit writer is satisfied that emissions from a representative sample of identical units at the facility are less than or equal to 50% of the applicable standard; and (5) the facility can demonstrate the ability to comply with this margin of compliance on an on-going basis.
4. For engines that meet the requirements in 3 above, only 50% of the engines are required to have an initial compliance test. Inconsistent test results may cause the remaining units to be tested.
5. All engines regardless of the type of turbocharging used (low or high) shall conduct initial compliance testing. The use of low speed or high speed turbochargers does not change the above initial test requirements.

Note: Purpose of adding in April 2015, to the engine monitoring protocol, the engine load calculation for stack testing. These statements are taken from a 2013 memo regarding an Area of Concern that was revealed during an inspection at a compressor station.

> "A review of emissions data during a current permit revision review process reveals a potential issue with the facility's determination of engine horsepower, load percent or fuel flow.
>
> The test data in question is from the November 17, 2010 and February 7, 2012 periodic testing of Emissions Unit 1a at the facility. This unit is a Superior, Model# 16SGTB, natural gas fired reciprocating engine.
>
> The test results from 2010 and 2012 report that the engine was operating at 39.7 and 40.0 percent (respectively) of full load which equates to 1053 and 1060 horsepower. The measured average fuel usage rate, of Unit 1a, during the three runs in 2010 was 3560 scf/hr and in 2012 was 4055 scf/hr. The measured fuel heating value of the natural gas was 1068 Btu/ft^3 in 2010 and 1019 in 2012 which means the engine's average fuel input was approximately 3.8 MMBtu/hr in 2010 and 4.13 MMBtu/hr in 2012. If the engine was actually operating at 1053 and 1060 horsepower, while burning 3.8 and 4.13 MMBtu/hr respectively, the Brake Specific Fuel Consumption (BSFC) would be:
>
> $$\text{BSFC(2010)} = \frac{\text{Fuel usage}}{\text{Horsepower}} = \frac{3{,}800{,}000 \text{ Btu/hr}}{1053 \text{ Hp}} = 3609 \text{ Btu/Hp-hr}$$
>
> and

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$$\text{BSFC(2012)} = \frac{\text{Fuel usage}}{\text{Horsepower}} = \frac{4{,}130{,}000\ \text{Btu/hr}}{1060\ \text{Hp}} = 3896\ \text{Btu/Hp-hr}$$

BSFC is basically a measure of the efficiency of an engine, the lower the number the more efficient the engine. Published data from Superior lists maximum engine efficiency (lowest potential BSFC) for this engine model at 7100 Btu/Hp-hr at 100 percent load. The BSFC increases to 7150 at 83 percent load and 7680 at 66 percent load. Therefore, the reported BSFC cannot be accurate. Either the estimated load percent and horsepower or the measured fuel usage rate is in error.

Why is this important?

In this situation, the source is only limited to numerical mass emission rates (lbs/hr) that are not directly linked to engine output horsepower. Therefore, the potential error in the calculated load and horsepower is secondary to determining compliance with the permitted emissions limit.

However, if we assume the fuel usage measurement is incorrect, the calculated mass emission rates would also be inaccurate given the source used the Method 19 F-factor and the measured emission concentrations to determine mass emission rates. In order to determine accurately the mass emission rate from only a pollutant concentration and the Method 19 F-factor, an accurate measurement of the fuel flow rate and heat content (Btu/scf) is critical. Given the reported fuel efficiency (i.e. BSFC) is approximately one-half the minimum achievable for this engine (3600 vs. 7100), it is reasonable to assume the mass emission rates are also underestimated by approximately 50 percent."